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Revised Comprehensive Exhibit List for Entry into Hearing Record Filed on 12.12.13 Hearing Exhibits 1 - 146

Hearing I.D. #	Witness	I.D. # As Filed	Exhibit Description	Entered
Staff				
1		Exhibit List	Comprehensive Exhibit List	
Service Hearing Exhibits (Pensacola – September 3, 2013 and Panama City Beach – September 4, 2013)				
2	Gulf Power Company	Customer Hearing Exhibit #1	Affidavit, customer notice, and proof of publication for Pensacola and Panama City service hearings (Composite)	
GULF POWER COMPANY (Gulf) (DIRECT)				
3	Gulf Power Company		Minimum Filing Requirement (MFR) Schedules - Sections A, B, C, D, E and F	
4	Margaret D. Neyman	MDN-1	MFR responsibility; Gulf's FPSC Complaint Activity 2002-2012; Customer Accounts O & M; Service Fees	
5	Angela G. Strickland	AGS-1	MFR responsibility; Customer Value Benchmark Results; Customer Service and Information O & M expense; O & M Benchmark Variance	

6	J. Andy McQuagge	JAM-1	MFR responsibility; Distribution System Components; Description of Typical Electric System; District Service Areas; Service Area and Customer Density Areas; Vaisala's National Lightning Detection Network Cloud-to-Ground Lightning 1997-2012; Distribution O & M Budget 2013-2017; Distribution O & M Benchmark Variance; 2013-2014 Distribution/Fleet Capital Additions Budget; Distribution Performance with CVB Survey	
7	Michael L. Burroughs	MLB-1	MFR responsibility; Owned and Operated or Jointly Owned Generating Capacity; Power Purchase Agreements; Annual EFOR; Peak Season EFOR; Gulf EFOR compared to peer group; Natural Gas Inventory	
8	Raymond W. Grove	RWG-1	MFR responsibility; Net Generation Capability by Type; Owned and Operated or Jointly Owned Generating Capacity; Power Purchase Agreements; 2013 Production Capital Additions Budget; 2014 Production Capital Additions Budget; 2014 Production O & M Budget; Planned Outages 2013 to 2017; Production O & M Expenses; Benchmark Comparison	
9	James O. Vick	JOV-1	Gulf's 2013 Environmental Compliance Program Update	
10	James O. Vick	JOV-2	Federal Register publication of the Mercury and Air Toxics Standards (MATS) rule	

11	P. Chris Caldwell	PCC-1	MFR responsibility; Transmission Capital Budget 2013 to 2014; MATS transmission projects through 2015; Transmission O & M Budget 2013-2017; Transmission O & M Benchmark Comparison; Transmission Reliability History	
12	Rhonda J. Alexander	RJA-1	MFR responsibility; Forecast 2011 and 2012 Cumulative Annual Growth in U.S. Real GDP; Residential Regression Model-Predicted vs. Actual; Small Commercial Regression Model-Predicted vs. Actual; Large Commercial Regression Model-Predicted vs. Actual	
13	R. Scott Teel	RST-1	MFR responsibility; 2011 Forecast vs. 2013 Forecast; Base Rate Capital Expenditures 2002 – 2014; Rate Case Drivers; Base Retail Return on Equity; Total Retail Capital Expenditures 2002 to 2014; Rule 25-14.004, Florida Administrative Code; Gulf Power Dividends Compared To Southern Company Capital Contributions 2011 to 2014	

14	James H. Vander Weide	JVW-1	Summary of Discounted Cash Flow Analysis for Electric Utilities; Comparison of the DCF Expected Return on an Investment in Electric Utilities to the Interest Rate on Moody's A-Rated Utility Bonds; Comparative Returns on S&P 500 Stock Index and Moody's A-Rated Bonds 1937-2013; Comparative Returns on S&P Utility Stock Index and Moody's A-Rated Utility Bonds 1937-2013; Using the Arithmetic Mean to Estimate the Cost of Equity Capital; Calculation of Capital Asset Pricing Model Cost of Equity Using the SBBI 6.7 Percent Risk Premium; Comparison of Risk Premiums on S&P 500 and S&P Utilities Index 1937-2013; Calculation of Capital Asset Pricing Model Cost of Equity Using DCF Estimate of the Expected Rate of Return on the Market Portfolio; Illustration of Calculation of Cost of Equity Required for the Company to have the same Weighted Average Cost of Capital As Comparable Electric Utilities	
15	James H. Vander Weide	JVW-2	Qualifications of James H. Vander Weide; Derivation of the Quarterly DCF Model; Adjusting for Flotation Costs in Determining a Public Utility's Allowed Rate of Return on Equity; Ex Ante Risk Premium Method; Ex Post Risk Premium Approach	

16	James M. Garvie	JMG-1	Fundamental beliefs regarding compensation and benefits; Base salary and total compensation to market median; Towers Watson memorandum on Audit of Gulf Power Company's compensation programs; Aon Hewitt comparison of employer-paid benefit value; Towers Watson comparison of employer-paid benefit value	
17	Steven P. Harris	SPH-1	Selected charts from the EQECAT Study	
18	Steven P. Harris	SPH-2	Gulf Power Company Transmission and Distribution Hurricane Loss and Reserve Performance Analysis performed by EQECAT (EQECAT Study)	
19	Peter S. Huck	PSH-1	Gulf's Depreciation Study	
20	Constance J. Erickson	CJE-1	MFR responsibility; A & G Budgeted Expenses; A & G Benchmark Variance; Depreciation and Dismantlement Calculation; 2013 Dismantling Study	
21	Richard J. McMillan	RJM-1	MFR responsibility; O & M Expenses Benchmark Variance by Function; Benchmark Year Recoverable O & M Expenses by Function; O & M Adjustments by Function; Hiring Lag	

22	Susan D. Ritenour	SDR-1	MFR responsibility; Planning and Budgeting Process Chart; Budget Process Chart; 2014 Test Year Capital Additions Budget By Function; 2014 Test Year Operation and Maintenance Expense By Function; Financial Model Flowchart; Balance Sheet December 2013 through December 2014; Income Statement for twelve months ended December 31, 2014; Utility Plant balances December 2013 through December 2014; 13-Month Average Rate Base; 13-Month Average Working Capital; Net Operating Income; Fuel Revenues and Expenses; Purchase Power Capacity Cost Recovery Clause Revenues and Expenses; Energy Conservation Cost Recovery Clause Revenues and Expenses; Environmental Cost Recovery Clause Revenues and Expenses; 2013 Rate Case Amortization; FPSC Assessment Fees; Income Taxes Adjustments; Interest Synchronization Adjustment; 13-Month Average Jurisdictional Cost of Capital; FPSC Adjusted Achieved Rate of Return and Return on Common Equity; Calculation of Revenue Deficiency; Revenue Expansion Factor & NOI Multiplier; General Plant Capital Additions for the Prior Year Ended 12/31/2013 and Test Year Ended 12/31/2014	
23	Susan D. Ritenour	SDR-2	Compliance-Related Transmission Investment and Expenses in Test Year ended 12/31/2014; Calculation of Step-Increase Effective July 1, 2015 for Compliance-Related Transmission (CRT) Costs for the period ended June 30, 2016; CRT-Deferred Return/Regulatory Asset	

24	Michael T. O'Sheasy	MTO-1	MFR responsibility; Illustration of Simple Distribution Network; MDS Customer/Demand Percentages by FERC Account	
25	Michael T. O'Sheasy	MTO-2	Analysis and Results of Cost of Service Study	
26	James I. Thompson	JIT-1	MFR responsibility; Allocation of Revenue Increase	
27	James I. Thompson	JIT-2	Proposed Tariff Sheets	
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28	Mark E. Garrett	MEG-1	Qualifications of Mark E. Garrett	
29	Mark E. Garrett	MEG-2	Garrett Group 24-State Incentive Survey	
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31	Scott Norwood	SN-1	Background and Experience of Scott Norwood	
32	Scott Norwood	SN-2	Transmission Upgrade Project Descriptions (CONFIDENTIAL)	
33	Scott Norwood	SN-3	Must-Run Criteria for Plant Crist and Plant Smith (CONFIDENTIAL)	
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37	Jacob Pous	JP-1	Recommended Depreciation Adjustments Summary	

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53	J. Randall Woolridge	JRW-9	DCF Model	
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56	J. Randall Woolridge	JRW-12	S&P Bond Ratings	
57	J. Randall Woolridge	JRW-13	Authorized ROEs for Electric Utilities and 10-Year Treasury Yields	
58	J. Randall Woolridge	JRW-14	Summary of Gulf Power Company's ROE Results	
59	J. Randall Woolridge	JRW-15	GDP and S&P Growth Rates	
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62	J. Randall Woolridge	JRW-16 APPENDIX C	Building Blocks Equity Risk Premium	
63	J. Randall Woolridge	JRW-16 APPENDIX D	The Use of Historical Returns to Measure an Expected Risk Premium	
WAL-MART STORES EAST, LP AND SAM'S EAST, INC. (Walmart) (DIRECT)				
64	Steve W. Chriss	SWC-1	Witness Qualification Statement	
65	Steve W. Chriss	SWC-2	Calculation of Test Year Jurisdictional Revenues Collected through Base Rates	
66	Steve W. Chriss	SWC-3	Reported Authorized Returns on Equity, Electric Utility Rates Cases Completed in 2012 and 2013	
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67	Michael P. Gorman	MPG-1	Rate of Return Adjusted Capital Structure 2014 Test Year	

68	Michael P. Gorman	MPG-2	Proxy Group	
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70	Michael P. Gorman	MPG-4	Constant Growth DCF Model (Consensus Analysts' Growth Rates)	
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74	Michael P. Gorman	MPG-8	Electricity Sales are Linked to US Economic Growth	
75	Michael P. Gorman	MPG-9	Multi-Stage Growth DCF Model	
76	Michael P. Gorman	MPG-10	Common Stock Market/Book Ratio	
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81	Michael P. Gorman	MPG-15	Value Line Beta	
82	Michael P. Gorman	MPG-16	CAPM Return	
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84	Michael P. Gorman	MPG-18	Accuracy of Interest Rate Forecasts (Long-Term Treasury Bond Yields – Projected vs. Actual)	
85	Greg R. Meyer	GRM-1	kWh Sales/Customer/Billing Day	
86	Greg R. Meyer	GRM-2	Historic and Forecasted Levels of Baseline Production Expense	
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87	Debra M. Dobiac	DMD-1	Auditor's Report—Twelve Months Ended Dec. 31, 2012	
88			Gulf's responses to Staff's First Set of Interrogatories, No. 1-11	
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90			Gulf's responses to Staff's Third Set of Interrogatories, Nos. 38-52	
91			Gulf's responses to Staff's Fourth Set of Interrogatories, Nos. 53-55	
92			Gulf's response to Staff's Fifth Set of Interrogatories, No. 56	
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94			Gulf's responses to Staff's Seventh Set of Interrogatories, Nos. 66-91	
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STATE OF FLORIDA
COUNTY OF ESCAMBIA

AFFIDAVIT

The undersigned ("Affiant"), being first duly sworn, deposes and says that:

1. Affiant is the Corporate Communications Manager for Gulf Power Company ("Gulf Power") and has personal knowledge of the facts stated herein.

2. Gulf Power, in order to provide the public with information regarding its request for rate increase before the Florida Public Service Commission ("Commission") in Docket 130140-EI, has provided information as detailed below in compliance with Section 25-22.0406 of the Florida Administrative Code, Commission Order No. PSC-13-0342-PCO-EI and the Notice of Customer Service Hearings issued August 16, 2013.

3. On July 12, 2013, Gulf Power mailed a copy of the Petition for Rate Increase to the chief executive officer of each county and municipality in the affected service area in compliance with Section 25-22.0406(2), Florida Administrative Code.

4. On July 12, 2013, Gulf Power placed copies of the Minimum Filing Requirements on file for public access and inspection at its corporate headquarters in Pensacola, Florida, and at its business offices in Pensacola, Ft. Walton Beach and Panama City, Florida, in compliance with Section 25-22.0406(3)(a), Florida Administrative Code.

5. On August 9, 2013, Gulf Power placed a Commission-approved Rate Case Synopsis on file for public access and inspection at its corporate headquarters in Pensacola, Florida, and at its business offices and the main public libraries in Pensacola, Ft. Walton Beach and Panama City, Florida, and mailed copies of the synopsis to the chief executive officers of each county and municipality in the affected service area in compliance with Sections 25-22.0406(4)(a) & (b), Florida Administrative Code. A copy of the synopsis is attached hereto and made a part hereof as Exhibit "A".

6. Between August 12 and August 23, 2013, a Commission-approved notice in the form of a separate, First Class mailing was sent to all of Gulf Power's customers at their billing address in compliance with Section 25-22.0406(5), Florida Administrative Code. A copy of the text of the notice is attached hereto and made a part hereof as Exhibit "B".

7. On August 20, 2013, Gulf Power published a Commission-approved display advertisement in the Pensacola News Journal and the Panama City News Herald which stated the date, time, location and purpose of the service hearings in compliance with Section 25-22.0406(6), Florida Administrative Code. Copies of the proof of publication as supplied from the respective publications are attached hereto and made a part hereof as Exhibit "C".

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130140-EI EXHIBIT 2
PARTY Pensacola & Panama City Service Hearing Exhibit - 9/3/13 - 9/4/13
DESCRIPTION Customer Hrg. EXH 1

FURTHER AFFIANT SAYETH NOT.

This 30th day of August, 2013.

Jeffrey S. Rogers

Sworn to and subscribed before me this 30th day of August, 2013. Said person is personally known to me and/or produced a current driver's license as identification.

(Notary Seal Must be Affixed)

NOTARY PUBLIC

MELISSA A. DARNES
MY COMMISSION # EE 150873
EXPIRES: December 17, 2015
Bonded Thru Budget Notary Services

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 130140-EI

GULF POWER
A SOUTHERN COMPANY

RATE CASE SYNOPSIS

I. PURPOSE

Pursuant to Rule 25-22.0406(4)(a), Gulf Power Company is providing a synopsis of its rate request.

II. COMPARISON OF THE PRESENT AND PROPOSED RATES FOR MAJOR SERVICES

Under Gulf's proposal, the following typical monthly bill increases would apply to the usage shown when the proposed new rates are put into effect on and after the first billing period in April, 2014.

A Residential Service monthly bill for 1,000 kWh would increase from $118.88 under the current rates to $127.82, a 7.5 percent increase.

A small commercial General Service monthly bill for 1,500 kWh would increase from $181.69 under the current rates to $191.17, a 5 percent increase.

A General Service Demand monthly bill for 25 kW and 11,000 kWh would increase from $1,008 under the current rates to $1,056, a 5 percent increase.

A Large Power Service monthly bill for 500 kW and 288,000 kWh would increase from $23,714 under the current rates to $25,421, a 7 percent increase.

A Large Power Service monthly bill for 658 kW and 288,000 kWh would increase from $25,336 under the current rates to $27,403, an 8 percent increase.

A Large Power Service monthly bill for 1,315 kW and 288,000 kWh would increase from $32,081 under the current rates to $35,645, an 11 percent increase.

A Large Power Service Time-of-Use monthly bill for 5,000 kW on-peak demand, 600,000 kWh on-peak energy, 5,000 kW max demand, and 1,800,000 kWh off-peak energy would increase from $203,297 under the current rates to $219,852, an 8 percent increase.

III. MAJOR RATE CASE ISSUES

The issues listed below are anticipated by Gulf Power Company (Gulf or the Company) to be areas considered; however, it is difficult to anticipate all the issues which may develop during a rate case.

1. What is the appropriate test year for setting base rates?
2. What is Gulf's test year rate base?
3. What is Gulf's test year cost of capital?
4. What is Gulf's test year net operating income?
5. What is the appropriate cost of service methodology?
6. What are the appropriate rate levels for each customer class?

Specific issues in this case will be identified in a prehearing order issued prior to the hearing.

IV. EXECUTIVE SUMMARY OF THE RATE CASE

Gulf Power is investing in our customers and communities through the largest power grid construction program in its history. Major capital investments have been and will be made to maintain our electric system, to strengthen and expand our existing infrastructure and to add new transmission lines. Part of the new transmission line construction is to help the Company comply with new federal environmental regulations that require plants to be shut down at regular intervals.

Gulf Power Company's Petition, new rate schedules, testimony, and Minimum Filing Requirements (MFRs) are filed pursuant to Section 366.06(3), Florida Statutes. Gulf seeks new base rates and charges which, based upon projected operations during the period January 2014 through December 2014 ("the test year"), would provide additional gross annual jurisdictional revenues of $74.4 million. This amount represents a 5.9 percent increase in retail revenues from sales of electricity. This revenue increase would allow for an overall rate of return of 6.47 percent and a return on equity (ROE) of 11.5 percent (the midpoint). If the Florida Public Service Commission (FPSC or the Commission) finds that mandatory environmental compliance related transmission investments should be included in base rates rather than through an alternative cost recovery mechanism such as the Environmental Cost Recovery Clause, Gulf Power is also requesting an additional $16.4 million increase to take effect in 2015.

If the request for rate increase is granted, the price for a residential customer buying 1,000 kilowatt hours of electricity in a month will increase in

April, 2014 by $8.94 or 7.5% over the current price of $118.88. In 2015, the price would increase an additional $1.99 per month if the Commission does not allow recovery of the environmental compliance related transmission investments discussed above through a cost recovery clause. The increased revenues sought by the Company are necessary to maintain efficient, reliable service and the Company's financial integrity. Without rate relief, the overall jurisdictional return earned in the test year would be only 4.05 percent and the jurisdictional return on common equity will fall to 5.14 percent which is well below the level determined to be reasonable by the Commission in Gulf's last rate case.

V. DESCRIPTION OF THE RATEMAKING PROCESS AND TIME SCHEDULE

A. Who is involved in the utility ratemaking process?

Many participants are involved in a utility rate case. Here is a list of some of the main participants:

1. **FPSC Commissioners** - The FPSC is composed of five commissioners appointed by the Governor. All five commissioners may sit on a rate case, or the case may be assigned by the Chairman of the FPSC to a panel of specific commissioners. The commissioners assigned to the case will make final decisions on all of the issues in the case based on the evidence received.

2. **FPSC Staff** - The commissioners are assisted by a staff which includes: attorneys who advise on legal issues; engineers who inspect utility sites and equipment; accountants who audit the utility's books and records; consumer affairs specialists who review complaints against the utilities; and rate and financial analysts who study financial and rate issues.

3. **The Utility** - Utility officers and staff, including accountants, rate analysts, engineers and others, testify and provide information about the utility, its operations and its revenues and expenses. The utility may also employ outside consultants as expert witnesses.

4. The **Office of Public Counsel** - The Office of Public Counsel (OPC) is appointed by the Legislature to represent the citizens of

Florida in cases before the Commission. OPC has a staff of attorneys, accountants, rate analysts and financial analysts, and may employ outside consultants as expert witnesses. OPC participates in major rate cases, analyzes information filed by the utility, assists members of the public who wish to testify and provides expert witnesses on various issues in the case.

5. **Intervenors** - Other interested parties representing consumer groups, industrial groups, commercial organizations, government entities and others participate in the ratemaking proceedings. An intervenor is someone who has been granted permission to participate as a party in order to represent a specific interest or point of view in the rate case through a petition to the Commission. Each intervenor has equal opportunity with the other parties and FPSC staff to ask questions, present testimony and cross-examine witnesses.

B. What is involved in the ratemaking process? What information is considered?

The ratemaking process involves months of analysis of volumes of information regarding all aspects of a utility's operations.

1. The rate case process begins when the utility writes a letter to the FPSC notifying the Commission of its proposed "test year" and filing date. The test year is a 12-month period for which utility operating data will be examined during the rate case. The letter

signals that the utility will likely ask for a rate increase. The "test year" letter starts a process that will likely continue over the next ten to fourteen months allowed under the Florida Statutes for the Commission to investigate the case.

2. Next, the utility files its formal request for a rate increase. This includes Minimum Filing Requirements (MFRs), which are required by the Commission's Rules. These MFRs contain hundreds of pages of figures and reports regarding the utility's expenses, investment and operations during the test year. The utility also files the testimony of its witnesses in support of the rate increase requested. The law requires that the utility carry the burden of proof and show why the requested increase is needed.

3. Before the ratemaking process is over, the Commission will try to gather all significant information about the utility. The FPSC staff, OPC and any other intervenors will typically ask for additional information as the case continues. This data provides details about the utility's supplies, expenses, taxes, construction expenditures, depreciation and other operating and financial matters that are crucial to making a decision in the case. The Commission's auditors will review the utility's books and records and file their report. Additional testimony may be filed by the utility, the FPSC staff, OPC and any other intervenors.

4. Hearings - a utility cannot change its prices (up or down) without authority from the Commission, and rate case procedures provide for public hearings as part of the Commission's decision-making process. These hearings are governed by rules similar to those used by courts. Witnesses are sworn and subject to cross-examination. The final decision made by the commissioners must be based upon information presented during the hearings.

   a. The first hearings are scheduled in the local service area to hear from customers. At these "service hearings" customers may tell the Commission about any service related issues they have experienced. This information may lead to the identification of issues that the Commission will investigate further as part of the case.

   b. After time for investigation of all information, the Commission will hold additional hearings for detailed review of all technical, legal, and financial issues in the case. These hearings may last for several days. Witnesses from all parties, including the utility, the FPSC staff, OPC and any other intervenors, present testimony and are cross-examined. Among the things the Commission looks for are expenditures that could be considered unnecessary or imprudent. Such expenditures would be disallowed for ratemaking purposes, which means ratepayers do not have

to pay for those costs. The hearings may be viewed online at the Commission's web site at: www.floridapsc.com/agendas/audiovideo/index.aspx

c. There are official transcripts of all hearings. Court reporters record the hearings, just like they do in a courtroom. These transcripts, and other official filings in this case, may be viewed online at the Commission's web site at: www.florida/dockets/cms/ using the following Docket Number: 130140.

5. After hearing, legal briefs are filed by the parties to summarize their positions. The Commission staff reviews the briefs and the record produced at hearing, and then produces a recommendation to the Commission that addresses each issue identified in the case.

6. The Commission then holds a Special Agenda Conference and votes on the issues, first on revenue requirements issues and then on rate issues. After the votes, Commission attorneys prepare a final order that reflects the Commission's votes and provides background for the case, the basis for each of the decisions reached, the new approved rates and the effective dates of the new rates. After the Commission order is issued, parties will have an opportunity to ask the Commission to reconsider its decision on the issues. After reconsideration, any party may appeal the final decision to the Florida Supreme Court.

GULF POWER COMPANY

2013 Retail Rate Case Schedule

(Docket No. 130140-EI)

Filing	July 12, 2013
Service Hearings	Pensacola Tuesday, September 3, 2013 4:00 p.m. CST Pensacola State College Hagler Auditorium 1000 College Boulevard *Note: Auditorium is at the corner of Underwood Avenue and N. 9th Avenue* Pensacola, Florida 32504 Panama City Wednesday, September 4, 2013 10:00 a.m. CST Edgewater Beach Conference Center 11212 Front Beach Road Panama City Beach, FL 32407
Pre-hearing Conference	November 15, 2013 Florida Public Service Commission 2540 Shumard Oak Boulevard Tallahassee, FL
Hearing	December 9 – 13, 2013 Florida Public Service Commission 2540 Shumard Oak Boulevard Tallahassee, FL

VI. GULF POWER LOCATIONS AT WHICH COMPLETE MFRs ARE AVAILABLE FOR INSPECTION

1. Panama City
   1230 E. 15th Street

2. Pensacola
   418 W. Garden Street

3. Milton
   5120 Dogwood Drive

4. Ft Walton Beach
   140 Hollywood Boulevard S.W.

5. Chipley
   1195 Jackson Avenue

6. Defuniak Springs
   1226 Circle Drive

7. Niceville
   1057 E. John Sims Parkway

8. Crestview
   1655 S. Ferdon Boulevard

NOTICE TO CUSTOMERS

On July 12, 2013, Gulf Power Company filed with the Florida Public Service Commission (FPSC) a request for approval to increase the Company's annual retail revenues. Currently, Gulf Power's total residential price (base rate plus all clause rates) is lower than it was in 2009. Gulf Power's proposed base rate request, if approved, would increase the total bill in April 2014 for a residential customer buying 1,000 kilowatt-hours by $8.94 per month or 7.5 percent — from $118.88 to $127.82. The company is requesting an additional increase in 2015 for transmission investments caused by mandatory federal environmental compliance requirements.

This filing has been assigned Docket No. 130140-EI by the FPSC. The Office of Public Counsel (OPC) has intervened in this Docket. The duty of the OPC is to provide legal representation for the people of the state in proceedings before the commission. OPC representatives may be contacted prior to the hearing at 111 West Madison St., Room 812, Tallahassee FL 32399-1400, or by phone at 1-800-342-0222.

Gulf Power is investing in customers and communities through the largest power grid construction program in its history. Major investments have been made to maintain our electric system, to strengthen our existing infrastructure and to add new transmission lines.

Part of the new transmission line construction is to help the company comply with new federal environmental regulations that will change the way we operate our plants and will require plants to be shut down at regular intervals. The new lines and equipment will be used to ensure voltage stability and reliable power flow.

From 2012 through 2015, we are investing $750 million dollars on maintenance, improvements and key transmission projects. These improvements are necessary to continue to provide reliable service to customers.

The present rates will remain in effect until new rates become operative under Florida Law. Copies of the rate case filing, including proposed rate schedules, are available for inspection at your local Gulf Power office.

Company personnel are available at all Gulf Power offices to answer questions concerning this request. They may be contacted at the address or telephone number on your electricity bill, at GulfPower.com or through a local directory.

A copy of the Minimum Filing Requirements (MFRs) and a summary or synopsis of our rate request can be found at www.gulfpower.com/filing. Additionally, these documents are available for review during normal business hours at the following public libraries:

City of Fort Walton Beach Public Library
185 Miracle Strip Pkwy. SW
Fort Walton Beach, FL 32548

West Florida Regional Library
200 W Gregory St.
Pensacola, FL 32502

Northwest Florida Regional Library
898 W 11th St.
Panama City, FL 32401

The Florida Public Service Commission will hold two public customer service hearings. The purpose of the hearings is to allow members of the public to give testimony regarding the proposed rates and the quality of service provided by Gulf Power Company.

The hearings are scheduled as follows:

Tuesday, Sept. 3 at 4 p.m. CST
Pensacola State College, Hagler Auditorium
1000 College Blvd., Pensacola, FL 32504
(Note: Hagler Auditorium is at the corner of Underwood Avenue and Ninth Avenue.)

Wednesday, Sept. 4 at 10 a.m. CST
Edgewater Beach Conference Center, 11212 Front Beach Rd.
Panama City Beach, FL 32407

Persons who wish to present testimony are urged to appear at the beginning of the hearings. If no witnesses are present to testify at that time, the hearings may be adjourned early.

The rate case hearings are scheduled to be held in Tallahassee on Dec. 9 – 13, 2013.

For your information, we are providing contact information for the Florida Public Service Commission's Consumer Affairs Department.

Consumer Affairs Department
Florida Public Service Commission
2540 Shumard Oak Blvd.
Tallahassee, FL 32399-0850
1-800-342-3552

The FPSC will also accept faxes and emails.
Fax number: 1-800-511-0809
Email address: contact@psc.state.fl.us

Current and proposed Rates

Rate Class	kW	kWh	Present Rate	2014 Proposed Rate
RS		1,000	$118.88	$127.82
GS		1,500	$181.69	$191.17
GSD	25	11,000	$1,007.54	$1,055.63
GSD	50	11,000	$1,160.10	$1,231.02
LP	500	288,000	$23,713.83	$25,421.48
LP	658	288,000	$25,336.00	$27,403.40
LP	1,315	288,000	$32,081.32	$35,644.69
LPT	5,000 Max	600,000 On	$203,297.09	$219,852.27
	5,000 On	1,800,000 Off		

Above prices include gross receipts tax.

Service Fees

Name	Present Charge	Proposed Charge
Connection of Initial Service – Residential	$27.00	$27.00
Connection of Initial Service – Non-Residential	$27.00	$50.00
Connection of Existing Service – Residential	$27.00	$27.00
Connection of Existing Service – Non-Residential	$27.00	$50.00
Restoration of Service (After Violation of Rules)	$35.00	$60.00
Restoration of Service After Hours (After Violation of Rules)	$55.00	$80.00
Restoration of Service at Pole (After Violation of Rules)	$95.00	$100.00
Premise Visit	$20.00	$30.00
Connection of Temporary Service	$110.00	$110.00
Investigation of Unauthorized Use	$75.00	$75.00
Returned Item Charge < $50	$25.00	$25.00
Returned Item Charge >$50 and < $300	$30.00	$30.00
Returned Item Charge >$300	$40.00	$40.00

PENSACOLA News Journal pnj.com

Published Daily-Pensacola, Escambia County, FL

PROOF OF PUBLICATION

State of Florida

County of Escambia:

Before the undersigned authority personally appeared **Anna Hammes** who, on oath, says that she is a personal representative of the Pensacola News Journal, a daily newspaper published in Escambia County, Florida; that the attached copy of advertisement, being a Legal in the matter of:

Notice

Was published in said newspaper in the issue(s) of:

August 20, 2013

Affiant further says that the said Pensacola News Journal is a newspaper published in said Escambia County, Florida, and that the said newspaper has heretofore been published in said Escambia County, Florida, and has been entered as second class matter at the Post Office in said Escambia County, Florida, for a period of one year next preceding the first publication of the attached copy of advertisement; and affiant further says that she has neither paid nor promised any person, firm or corporation any discount, rebate, commission or refund for the purpose of securing this advertisement for publication in the said newspaper.

Sworn to and subscribed before me this **20th Day** of **August, 2013**, by **Anna Hammes**, who is personally known to me.

Anna Hammes Affiant

Carol S Corbin Notary Public

CAROL S. CORBIN
NOTARY PUBLIC - STATE OF FLORIDA
COMMISSION #EE847370
MY COMMISSION EXPIRES OCT. 29, 2016

Notice

The Florida Public Service Commission announces a customer service hearing to be held in the following docket, to which all interested persons and parties are invited to attend.

Docket No.130140-EI
Request for rate increase by
Gulf Power Company

DATE AND TIME:
Tuesday, September 3, 2013
4:00 p.m. CST

PLACE:
Pensacola State College
Hagler Auditorium
1000 College Boulevard
Pensacola, FL 32504

The hearing will begin as scheduled and will continue until all witnesses have been heard. If no witnesses are present, the hearing may be adjourned. All persons desiring to present testimony are urged to appear at the beginning of the hearing since the hearing may be adjourned early if no witnesses are present to testify.

PURPOSE: To permit members of the public to give testimony regarding the rates and service of Gulf Power Company. All witnesses shall be subject to cross-examination at the conclusion of their testimony. Any person requiring accommodations at this hearing because of a physical impairment should call the Office of the Commission Clerk at (850) 413-6770 at least 48 hours prior to the hearing. Any person who is hearing or speech impaired should contact the Commission by using the Florida Relay Service, which can be reached at 1-800-955-8771.

Legal No 1606186 1T August 20, 2013

Halifax Media Group

PUBLISHERS OF THE NEWS HERALD
Panama City, Bay County, Florida
Published Daily

State of Florida
County of Bay

Before the undersigned authority appeared Lynda Speights, who on oath says that she is Legal Advertising Representative of The News Herald, a daily newspaper published at Panama City, in Bay County, Florida; that the attached copy of advertisement, being a Legal Advertisement # **92166** in the matter of **PUBLIC NOTICE - Gulf Power** in the Bay County Court, was published in said newspaper in the issue of

August 20, 2013.

Affiant further says that The News Herald is a direct successor of the Panama City News and that this publication, together with its direct predecessor, has been continuously published in said Bay County, Florida, each day (except that the predecessor, Panama City News, was not published on Sundays), and that this publication together with its said predecessor, has been entered as periodicals matter at the post office in Panama City, in said Bay County, Florida, for a period of 1 year next preceding the first publication of the attached copy of advertisement; and affiant further says that he or she has neither paid nor promised any person, firm or corporation any discount, rebate, commission or refund for the purpose of securing this advertisement for publication in the said newspaper.

State of Florida
County of Bay
Sworn and subscribed before me this **20th** day of **August**, A.D., **2013**, by Lynda Speights, Legal Advertising Representative of The News Herald, who is personally known to me or has produced N/A as identification.

Notary Public State of Florida
Marie Forrest
My Commission EE089458
Expires 05/05/2015

Notary Public, State of Florida at Large

92166
PUBLIC NOTICE

The Florida Public Service Commission announces a customer service hearing to be held in the following docket, to which all interested persons and parties are invited to attend.

Docket No. 130140-EI
Request for rate increase by Gulf Power Company

DATE AND TIME:
Wednesday, September 4, 2013 10:00 a.m. CST

PLACE:
Edgewater Beach Conference Center
11212 Front Beach Rd.
Panama City Beach, FL 32407

The hearing will begin as scheduled and will continue until all witnesses have been heard. If no witnesses are present, the hearing may be adjourned. All persons desiring to present testimony are urged to appear at the beginning of the hearing since the hearing may be adjourned early if no witnesses are present to testify.

PURPOSE: To permit members of the public to give testimony regarding the rates and service of Gulf Power Company. All witnesses shall be subject to cross-examination at the conclusion of their testimony. Any person requiring accommodations at this hearing because of a physical impairment should call the Office of the Commission Clerk at (850) 413-6770 at least 48 hours prior to the hearing. Any person who is hearing or speech impaired should contact the Commission by using the Florida Relay Service, which can be reached at 1-800-955-8771.

FILED JUL 12, 2013
DOCUMENT NO. 03974-13
FPSC - COMMISSION CLERK

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 130140-EI

GULF POWER
A SOUTHERN COMPANY

MINIMUM FILING REQUIREMENTS

SECTION A – EXECUTIVE SUMMARY SCHEDULES

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130140-EI EXHIBIT 3
PARTY Gulf Power Company (Gulf) Direct
DESCRIPTION MFRs, Sections A, B, C,D, E, and F

GULF POWER COMPANY

Docket No. 130140-EI
Minimum Filing Requirements

Index

A. Executive Summary Schedules

Schedules	Witness	Title	Page
A-1	Teel Ritenour	Full Revenue Requirements Increase Requested	1
A-2	Thompson	Full Revenue Requirements Bill Comparison – Typical Monthly Bills	2
A-3	Thompson	Summary of Tariffs	7
A-4	Ritenour	Interim Revenue Requirements Increase Requested	10
A-5	Thompson	Interim Revenue Requirements Bill Comparison – Typical Monthly Bills	11

Schedule A-1 | FULL REVENUE REQUIREMENTS INCREASE REQUESTED | Page 1 of 1

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide the calculation of the requested full revenue requirements increase.

($000's)

Type of Data Shown:
X Projected Test Year Ended 12/31/14
__ Prior Year Ended 12/31/13
__ Historical Year Ended 12/31/12
__ Witness: R. S. Teel, S. D. Ritenour

(1) Line No.	(2) Description	(3) Source		(4) Amount
1	Jurisdictional Adjusted Rate Base	Schedule B-1		$ 1,883,901
2	Rate of Return on Rate Base Requested	Schedule D-1a		x 6.47%
3	Jurisdictional Net Operating Income Requested	Line 1 x Line 2		$ 121,888
4	Jurisdictional Adjusted Net Operating Income	Schedule C-1		76,359
5	Net Operating Income Deficiency	Line 3 - Line 4		$ 45,529
6	Earned Rate of Return	Line 4 / Line 1	4.05%	
7	Net Operating Income Multiplier	Schedule C-44		x 1.633971
8	Revenue Increase Requested	Line 5 x Line 7		$ 74,393

Supporting Schedules: B-1, C-1, C-44, D-1a

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: For each rate, calculate typical monthly bills for present rates and proposed rates.

Type of Data Shown:
_X_ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
___ Historical Year Ended 12/31/12
Witness: J. I. Thompson

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
				BILL UNDER PRESENT RATES $					
Line No.	RATE CLASS	TYPICAL KW	TYPICAL kWh	BASE RATE	FUEL CHARGE	ECCR CHARGE	CAPACITY CHARGE	ENVIRONMENTAL CHARGE	TOTAL
1	RS		1,000	$58.13	$38.32	$2.26	$4.67	$12.53	$115.91

(11)	(12)	(13)	(14)	(15)	(16)
2			BILL UNDER PROPOSED RATES $		
3 BASE RATE	FUEL CHARGE	ECCR CHARGE	CAPACITY CHARGE	ENVIRONMENTAL CHARGE	TOTAL
5 $66.84	$38.32	$2.26	$4.67	$12.53	$124.62

(17)	(18)	(19)	(20)
6	INCREASE	CENTS PER kWh	
7 $	%	PRESENT	PROPOSED
8 (16) - (10)	(17) / (10)	(10) / (4)	(16) / (4)
9 $8.71	7.51%	11.591	12.462

(21)	(22)	(23)	(24)
10		PRESENT	PROPOSED
11 BASE CHARGE		$15.00	$18.00
12 DEMAND CHARGE	$/KW	-	-
13 ENERGY CHARGE	CENTS/kWh	4.313	4.884
14 FUEL CHARGE	CENTS/kWh	3.832	3.832
15 CONSERVATION CHARGE	CENTS/kWh	0.226	0.226
16 CAPACITY CHARGE	CENTS/kWh	0.467	0.467
17 ENVIRONMENTAL CHARGE	CENTS/kWh	1.253	1.253

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: For each rate, calculate typical monthly bills for present rates and proposed rates.

Type of Data Shown:
_X_ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
___ Historical Year Ended 12/31/12
Witness: J. I. Thompson

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
				BILL UNDER PRESENT RATES $					
Line No.	RATE CLASS	TYPICAL KW	TYPICAL kWh	BASE RATE	FUEL CHARGE	ECCR CHARGE	CAPACITY CHARGE	ENVIRONMENTAL CHARGE	TOTAL
1	GS		1,500	$91.26	$57.48	$3.35	$6.39	$18.66	$177.14

	(11)	(12)	(13)	(14)	(15)	(16)
2			BILL UNDER PROPOSED RATES $			
3	BASE	FUEL	ECCR	CAPACITY	ENVIRONMENTAL	
4	RATE	CHARGE	CHARGE	CHARGE	CHARGE	TOTAL
5	$100.50	$57.48	$3.35	$6.39	$18.66	$186.38

	(17)	(18)	(19)	(20)
6	INCREASE		CENTS PER kWh	
7	$	%	PRESENT	PROPOSED
8	(16) - (10)	(17) / (10)	(10) / (4)	(16) / (4)
9	$9.24	5.22%	11.809	12.425

	(21)	(22)	(23)	(24)
10			PRESENT	PROPOSED
11	BASE CHARGE		$18.00	$21.00
12	DEMAND CHARGE	$/KW	-	-
13	ENERGY CHARGE	CENTS/kWh	4.884	5.300
14	FUEL CHARGE	CENTS/kWh	3.832	3.832
15	CONSERVATION CHARGE	CENTS/kWh	0.223	0.223
16	CAPACITY CHARGE	CENTS/kWh	0.426	0.426
17	ENVIRONMENTAL CHARGE	CENTS/kWh	1.244	1.244

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: For each rate, calculate typical monthly bills for present rates and proposed rates.

Type of Data Shown:
_X_ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
___ Historical Year Ended 12/31/12
Witness: J. I. Thompson

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
				BILL UNDER PRESENT RATES $					
Line No.	RATE CLASS	TYPICAL KW	TYPICAL kWh	BASE RATE	FUEL CHARGE	ECCR CHARGE	CAPACITY CHARGE	ENVIRONMENTAL CHARGE	TOTAL
1	GSD	25	11,000	$360.50	$421.52	$24.09	$40.59	$135.63	$982.33
2	GSD	50	11,000	$509.25	$421.52	$24.09	$40.59	$135.63	$1,131.08

	(11)	(12)	(13)	(14)	(15)	(16)
3			BILL UNDER PROPOSED RATES $			
4	BASE	FUEL	ECCR	CAPACITY	ENVIRONMENTAL	
5	RATE	CHARGE	CHARGE	CHARGE	CHARGE	TOTAL
6	$407.39	$421.52	$24.09	$40.59	$135.63	$1,029.22
7	$578.39	$421.52	$24.09	$40.59	$135.63	$1,200.22

	(17)	(18)	(19)	(20)
8	INCREASE		CENTS PER kWh	
9	$	%	PRESENT	PROPOSED
10	(16) - (10)	(17) / (10)	(10) / (4)	(16) / (4)
11	$46.89	4.77%	8.930	9.357
12	$69.14	6.11%	10.283	10.911

	(21)	(22)	(23)	(24)
13			PRESENT	PROPOSED
14	BASE CHARGE		$44.00	$44.00
15	DEMAND CHARGE	$/KW	$5.95	$6.84
16	ENERGY CHARGE	CENTS/kWh	1.525	1.749
17	FUEL CHARGE	CENTS/kWh	3.832	3.832
18	CONSERVATION CHARGE	CENTS/kWh	0.219	0.219
19	CAPACITY CHARGE	CENTS/kWh	0.369	0.369
20	ENVIRONMENTAL CHARGE	CENTS/kWh	1.233	1.233

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: For each rate, calculate typical monthly bills for present rates and proposed rates.

Type of Data Shown:
_X_ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
___ Historical Year Ended 12/31/12
Witness: J. I. Thompson

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
				BILL UNDER PRESENT RATES $					
Line No.	RATE CLASS	TYPICAL KW	TYPICAL kWh	BASE RATE	FUEL CHARGE	ECCR CHARGE	CAPACITY CHARGE	ENVIRONMENTAL CHARGE	TOTAL
1	LP	500	288,000	$7,390.00	$10,771.20	$604.80	$912.96	$3,441.60	$23,120.56
2	LP	658	288,000	$8,971.58	$10,771.20	$604.80	$912.96	$3,441.60	$24,702.14
3	LP	1,315	288,000	$15,548.15	$10,771.20	$604.80	$912.96	$3,441.60	$31,278.71

	(11)	(12)	(13)	(14)	(15)	(16)
4			BILL UNDER PROPOSED RATES $			
5	BASE	FUEL	ECCR	CAPACITY	ENVIRONMENTAL	
6	RATE	CHARGE	CHARGE	CHARGE	CHARGE	TOTAL
7	$9,054.92	$10,771.20	$604.80	$912.96	$3,441.60	$24,785.48
8	$10,987.26	$10,771.20	$604.80	$912.96	$3,441.60	$26,717.82
9	$19,022.37	$10,771.20	$604.80	$912.96	$3,441.60	$34,752.93

	(17)	(18)	(19)	(20)
10	INCREASE		CENTS PER kWh	
11	$	%	PRESENT	PROPOSED
12	(16) - (10)	(17) / (10)	(10) / (4)	(16) / (4)
13	$1,664.92	7.20%	8.028	8.606
14	$2,015.68	8.16%	8.577	9.277
15	$3,474.22	11.11%	10.861	12.067

	(21)	(22)	(23)	(24)
16			PRESENT	PROPOSED
17	BASE CHARGE		$225.00	$250.00
18	DEMAND CHARGE	$/KW	$10.01	$12.23
19	ENERGY CHARGE	CENTS/kWh	0.750	0.934
20	FUEL CHARGE	CENTS/kWh	3.740	3.740
21	CONSERVATION CHARGE	CENTS/kWh	0.210	0.210
22	CAPACITY CHARGE	CENTS/kWh	0.317	0.317
23	ENVIRONMENTAL CHARGE	CENTS/kWh	1.195	1.195

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: For each rate, calculate typical monthly bills for present rates and proposed rates.

Type of Data Shown:
_X_ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
___ Historical Year Ended 12/31/12
Witness: J. I. Thompson

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
				BILL UNDER PRESENT RATES $					
Line No.	RATE CLASS	TYPICAL KW	TYPICAL kWh	BASE RATE	FUEL CHARGE	ECCR CHARGE	CAPACITY CHARGE	ENVIRONMENTAL CHARGE	TOTAL
1	LPT	5,000 Max	600,000 On	$68,425.00	$88,458.00	$5,040.00	$7,608.00	$28,680.00	$198,211.00
2		5,000 On	1,800,000 Off						

(11)	(12)	(13)	(14)	(15)	(16)
		BILL UNDER PROPOSED RATES $			
BASE RATE	FUEL CHARGE	ECCR CHARGE	CAPACITY CHARGE	ENVIRONMENTAL CHARGE	TOTAL
$84,566.00	$88,458.00	$5,040.00	$7,608.00	$28,680.00	$214,352.00

(17)	(18)	(19)	(20)
INCREASE		CENTS PER kWh	
$ (16) - (10)	% (17) / (10)	PRESENT (10) / (4)	PROPOSED (16) / (4)
$16,141.00	8.14%	8.259	8.931

(21)	(22)	(23)	(24)
		PRESENT	PROPOSED
BASE CHARGE		$225.00	$250.00
MAX DEMAND CHARGE	$/KW	$2.00	$2.54
ON-PEAK DEMAND CHARGE	$/KW	$8.04	$9.84
ON-PEAK ENERGY CHARGE	CENTS/kWh	0.750	0.934
OFF-PEAK ENERGY CHARGE	CENTS/kWh	0.750	0.934
ON-PEAK FUEL CHARGE	CENTS/kWh	4.654	4.654
OFF-PEAK FUEL CHARGE	CENTS/kWh	3.363	3.363
CONSERVATION CHARGE	CENTS/kWh	0.210	0.210
CAPACITY CHARGE	CENTS/kWh	0.317	0.317
ENVIRONMENTAL CHARGE	CENTS/kWh	1.195	1.195

Supporting Schedules: A-3

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide a summary of all proposed changes in rates and rate classes, detailing current and proposed classes of service, demand, energy, and other service charges.

Type of Data Shown:
_X_ Projected Test Year Ended 12/31/14
____ Prior Year Ended 12/31/13
____ Historical Year Ended 12/31/12
Witness: J. I. Thompson

(1) Line No.	(2) Current Rate Schedule	(3) Type of Charge	(4) Current Rate	(5) Proposed Rate Schedule	(6) Proposed Rate	(7) Percent Increase
1	RS	BASE ($/Customer)	$15.00 /Month	RS	$0.60 /Day	20%
2		ENERGY (¢/kWh)	4.313		4.884	13%
3	GS	BASE ($/Customer)	$18.00	GS	$21.00	17%
4		ENERGY (¢/kWh)	4.884		5.300	9%
5	GSD	DEMAND ($/KW)	$5.95	GSD	$6.84	15%
6		ENERGY (¢/kWh)	1.525		1.749	15%
7		PRIMARY DISCOUNT ($/KW)	($0.29)		($0.39)	34%
8	LP	BASE ($/Customer)	$225.00	LP	$250.00	11%
9		DEMAND ($/KW)	$10.01		$12.23	22%
10		ENERGY (¢/kWh)	0.750		0.934	25%
11		PRIMARY DISCOUNT ($/KW)	($0.41)		($0.55)	34%
12		TRANSMISSION DISCOUNT ($/KW)	($0.56)		($0.78)	39%
13	PX	BASE ($/Customer)	$646.84	PX	$743.22	15%
14		DEMAND ($/KW)	$9.44		$10.85	15%
15		ENERGY (¢/kWh)	0.349		0.399	14%
16	RSVP	BASE ($/Customer)	$15.00 /Month	RSVP	$0.60 /Day	20%
17		ENERGY Critical (¢/kWh)	4.313		4.884	13%
18		ENERGY High (¢/kWh)	4.313		4.884	13%
19		ENERGY Medium (¢/kWh)	4.313		4.884	13%
20		ENERGY Low (¢/kWh)	4.313		4.884	13%

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide a summary of all proposed changes in rates and rate classes, detailing current and proposed classes of service, demand, energy, and other service charges.

Type of Data Shown:
_X_ Projected Test Year Ended 12/31/14
____ Prior Year Ended 12/31/13
____ Historical Year Ended 12/31/12
Witness: J. I. Thompson

(1) Line No.	(2) Current Rate Schedule	(3) Type of Charge	(4) Current Rate	(5) Proposed Rate Schedule	(6) Proposed Rate	(7) Percent Increase
1	GSTOU	ENERGY Summer On (¢/kWh)	16.391	GSTOU	18.691	14%
2		ENERGY Summer Int. (¢/kWh)	6.119		6.978	14%
3		ENERGY Summer Off (¢/kWh)	2.545		2.902	14%
4		ENERGY Winter (¢/kWh)	3.562		4.062	14%
5	GSDT	DEMAND Maximum ($/KW)	$2.82	GSDT	$3.24	15%
6		DEMAND On-Peak ($/KW)	$3.18		$3.66	15%
7		ENERGY On-Peak (¢/kWh)	1.525		1.749	15%
8		ENERGY Off-Peak (¢/kWh)	1.525		1.749	15%
9		PRIMARY DISCOUNT ($/KW)	($0.29)		($0.39)	34%
10		CRITICAL PEAK OPTION:				
11		DEMAND Maximum ($/KW)	$2.82		$3.24	15%
12		DEMAND On-Peak ($/KW)	$1.59		$1.83	15%
13		DEMAND Critical Peak ($/KW)	$4.77		$5.49	15%
14	LPT	BASE ($/Customer)	$225.00	LPT	$250.00	11%
15		DEMAND Maximum ($/KW)	2.00		$2.54	27%
16		DEMAND On-Peak ($/KW)	8.04		$9.84	22%
17		ENERGY On-Peak (¢/kWh)	0.750		0.934	25%
18		ENERGY Off-Peak (¢/kWh)	0.750		0.934	25%
19		PRIMARY DISCOUNT ($/KW)	($0.41)		($0.55)	34%
20		TRANSMISSION DISCOUNT ($/KW)	($0.56)		($0.78)	39%
21		CRITICAL PEAK OPTION:				
22		DEMAND Maximum ($/KW)	$2.00		$2.54	27%
23		DEMAND On-Peak ($/KW)	$4.02		$4.92	22%
24		DEMAND Critical Peak ($/KW)	$12.06		$14.76	22%

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide a summary of all proposed changes in rates and rate classes, detailing current and proposed classes of service, demand, energy, and other service charges.

Type of Data Shown:
_X_ Projected Test Year Ended 12/31/14
____ Prior Year Ended 12/31/13
____ Historical Year Ended 12/31/12
Witness: J. I. Thompson

(1) Line No.	(2) Current Rate Schedule	(3) Type of Charge	(4) Current Rate	(5) Proposed Rate Schedule	(6) Proposed Rate	(7) Percent Increase
1	PXT	BASE ($/Customer)	$646.84	PXT	$743.22	15%
2		DEMAND Maximum ($/KW)	$0.78		$0.90	15%
3		DEMAND On-Peak ($/KW)	$8.76		$10.07	15%
4		ENERGY On-Peak (¢/kWh)	0.345		0.399	16%
5		ENERGY Off-Peak (¢/kWh)	0.345		0.399	16%
6	SBS	100 TO 499 KW		SBS		
7		DEMAND CHARGE:				
8		ON-PEAK DEMAND ($/KW)	$3.18		$3.66	15%
9		RESERVATION CHARGE ($/KW)	$0.95		$1.18	24%
10		SUM DAILY ON-PK STANDBY ($/KW)	$0.45		$0.56	24%
11		ENERGY (¢/kWh)	1.930		3.460	79%
12		PRIMARY DISCOUNT ($/KW)	($0.07)		($0.06)	-14%
13		500 TO 7,499 KW				
14		DEMAND CHARGE:				
15		ON-PEAK DEMAND ($/KW)	$8.04		$9.84	22%
16		RESERVATION CHARGE ($/KW)	$0.95		$1.18	24%
17		SUM DAILY ON-PK STANDBY ($/KW)	$0.45		$0.56	24%
18		ENERGY (¢/kWh)	1.055		3.460	228%
19		PRIMARY DISCOUNT ($/KW)	($0.07)		($0.06)	-14%
20		TRANSMISSION DISCOUNT ($/KW)	($0.09)		($0.07)	-22%
21		ABOVE 7,499 KW				
22		DEMAND CHARGE:				
23		LOCAL FACILITIES ($/KW)	$0.81		$1.04	28%
24		ON-PEAK DEMAND ($/KW)	$8.76		$10.07	15%
25		RESERVATION CHARGE ($/KW)	$0.98		$1.21	23%
26		SUM DAILY ON-PK STANDBY ($/KW)	$0.47		$0.57	21%
27		ENERGY (¢/kWh)	1.022		3.460	239%
28		TRANSMISSION DISCOUNT ($/KW)	($0.07)		($0.06)	-14%

Schedule A-4	INTERIM REVENUE REQUIREMENTS INCREASE REQUESTED	Page 1 of 1
FLORIDA PUBLIC SERVICE COMMISSION	EXPLANATION: Provide the calculation of the requested interim revenue requirements increase.	Type of Data Shown: __Projected Test Year Ended 12/31/14 __Prior Year Ended 12/31/13 __Historical Year Ended 12/31/12
COMPANY: GULF POWER COMPANY		
DOCKET NO.: 130140-EI	($000's)	Witness: S. D. Ritenour

(1) Line No.	(2) Description	(3) Source	(4) Amount

Not Applicable. Gulf Power is not requesting an interim revenue requirements increase.

10

Supporting Schedules:

Recap Schedules:

Schedule A-5	INTERIM REVENUE REQUIREMENTS BILL COMPARISON - TYPICAL MONTHLY BILLS	Page 1 of 1
FLORIDA PUBLIC SERVICE COMMISSION	EXPLANATION: For each rate, calculate typical monthly bills for present rates and proposed interim rates.	Type of Data Shown:
		___ Projected Test Year Ended 12/31/14
COMPANY: GULF POWER COMPANY		___ Prior Year Ended 12/31/13
		_X_ Historical Year Ended 12/31/12
DOCKET NO.: 130140-EI		Witness: J. I. Thompson

Not Applicable. Gulf Power is not requesting an interim revenue requirements increase.

Supporting Schedules:

Recap Schedules:

FILED JUL 12, 2013
DOCUMENT NO. 03975-13
FPSC - COMMISSION CLERK

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 130140-EI

GULF POWER

A SOUTHERN COMPANY

MINIMUM FILING REQUIREMENTS

SECTION B – RATE BASE SCHEDULES

GULF POWER COMPANY

Docket No. 130140-EI
Minimum Filing Requirements

Index

B. Rate Base Schedules

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GULF POWER COMPANY

Docket No. 130140-EI
Minimum Filing Requirements

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B. Rate Base Schedules

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FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide a schedule of the 13-month average adjusted ratebase for the test year, the prior year and the most recent historical year. Provide the details of all adjustments on Schedule B-2.

Type of Data Shown:
X Projected Test Year Ended 12/31/14
____ Prior Year Ended 12/31/13
____ Historical Year Ended 12/31/12
Witness: S. D. Ritenour

Adjusted 13-Month Average Rate Base
($000's)

(1) Line No.	(2) Rate Base Components	(3) Total Company per Books	(4) Non-Electric Utility	(5) Electric Utility (3) + (4)	(6) Commission Adjustments Made in Last Case as Applicable (Sch. B-2)	(7) Adjusted per Commission (5)+(6)	(8) Company Adjustments (Sch. B-2)	(9) Total Utility with Commission & Company Adjustments (7) + (8)	(10) Unit Power Sales Rate Base	(11) Total Utility Adjusted for UPS (9) - (10)	(12) Jurisdictional Rate Base Factor	(13) Jurisdictional Utility Adjusted Per Company & Commission (11) x (12)
1	Plant-in-Service	4,480,719	0	4,480,719	(1,083,115)	3,397,604	(6,528)	3,391,076	(391,179)	2,999,897	0.9814230	2,944,168
2	Accumulated Depreciation & Amortization	(1,549,548)	0	(1,549,548)	151,312	(1,398,236)	192	(1,398,044)	129,995	(1,268,049)	0.9804976	(1,243,319)
3	Net Plant-in-Service (1) - (2)	2,931,171	0	2,931,171	(931,803)	1,999,368	(6,336)	1,993,032	(261,184)	1,731,848	0.9821006	1,700,849
4	Plant Held for Future Use	18,456	0	18,456	(13,021)	5,435	0	5,435	0	5,435	0.9707452	5,276
5	Construction Work-in-Progress	409,402	0	409,402	(375,555)	33,847	0	33,847	(6,557)	27,290	0.9767680	26,656
6	Plant Acquisition Adjustment	1,903	0	1,903	0	1,903	0	1,903	(1,903)	0		0
7	Net Utility Plant (3)+(4)+(5)+(6)	3,360,932	0	3,360,932	(1,320,379)	2,040,553	(6,336)	2,034,217	(269,644)	1,764,573	0.9819832	1,732,781
8	Working Capital Allowance	170,527	(13,029)	157,498	8,872	166,370	(2,750)	163,620	(8,424)	155,196	0.9737364	151,120
9	Total Rate Base (7) + (8)	3,531,459	(13,029)	3,518,430	(1,311,507)	2,206,923	(9,086)	2,197,837	(278,068)	1,919,769		1,883,901

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide a schedule of the 13-month average adjusted ratebase for the test year, the prior year and the most recent historical year. Provide the details of all adjustments on Schedule B-2.

Type of Data Shown:
____Projected Test Year Ended 12/31/14
_X_Prior Year Ended 12/31/13
____Historical Year Ended 12/31/12
Witness: S. D. Ritenour

Adjusted 13-Month Average Rate Base
($000's)

(1) Line No.	(2) Rate Base Components	(3) Total Company per Books	(4) Non-Electric Utility	(5) Electric Utility (3) + (4)	(6) Commission Adjustments Made in Last Case as Applicable (Sch. B-2)	(7) Adjusted per Commission (5)+(6)	(8) Company Adjustments (Sch. B-2)	(9) Total Utility with Commission & Company Adjustments (7) + (8)	(10) Unit Power Sales Rate Base	(11) Total Utility Adjusted for UPS (9) - (10)	(12) Jurisdictional Rate Base Factor	(13) Jurisdictional Utility Adjusted Per Company & Commission (11) x (12)
1	Plant-in-Service	4,320,808	0	4,320,808	(1,072,531)	3,248,277	0	3,248,277	(381,680)	2,866,597	0.9814230	2,813,344
2	Accumulated Depreciation & Amortization	(1,427,964)	0	(1,427,964)	111,557	(1,316,407)	0	(1,316,407)	122,666	(1,193,741)	0.9804976	(1,170,460)
3	Net Plant-in-Service (1) - (2)	2,892,844	0	2,892,844	(960,974)	1,931,870	0	1,931,870	(259,014)	1,672,856	0.9820833	1,642,884
4	Plant Held for Future Use	18,456	0	18,456	(13,021)	5,435	0	5,435	0	5,435	0.9707452	5,276
5	Construction Work-in-Progress	198,967	0	198,967	(162,840)	36,127	0	36,127	(6,234)	29,893	0.9767680	29,199
6	Plant Acquisition Adjustment	2,159	0	2,159	0	2,159	0	2,159	(2,159)	0		0
7	Net Utility Plant (3)+(4)+(5)+(6)	3,112,426	0	3,112,426	(1,136,835)	1,975,591	0	1,975,591	(267,407)	1,708,184	0.9819545	1,677,359
8	Working Capital Allowance	217,679	(13,050)	204,629	5,359	209,988	0	209,988	(9,296)	200,692	0.9739900	195,472
9	Total Rate Base (7) + (8)	3,330,105	(13,050)	3,317,055	(1,131,476)	2,185,579	0	2,185,579	(276,703)	1,908,876		1,872,831

Supporting Schedules: B-2, B-3, B-5, B-6, B-7, B-8, B-9, B-10, B-13, B-15, B-17, F-8

Recap Schedules: A-1

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide a schedule of the 13-month average adjusted ratebase for the test year, the prior year and the most recent historical year. Provide the details of all adjustments on Schedule B-2.

Type of Data Shown:
_____Projected Test Year Ended 12/31/14
_____Prior Year Ended 12/31/13
_X_Historical Year Ended 12/31/12
Witness: S. D. Ritenour

Adjusted 13-Month Average Rate Base
($000's)

(1) Line No.	(2) Rate Base Components	(3) Total Company per Books	(4) Non-Electric Utility	(5) Electric Utility (3) + (4)	(6) Commission Adjustments Made in Last Case as Applicable (Sch. B-2)	(7) Adjusted per Commission (5)+(6)	(8) Company Adjustments (Sch. B-2)	(9) Total Utility with Commission & Company Adjustments (7) + (8)	(10) Unit Power Sales Rate Base	(11) Total Utility Adjusted for UPS (9) - (10)	(12) Jurisdictional Rate Base Factor	(13) Jurisdictional Utility Adjusted Per Company & Commission (11) x (12)
1	Plant-in-Service	4,048,835	0	4,048,835	(998,452)	3,050,383	0	3,050,383	(368,523)	2,681,860	0.9814230	2,632,039
2	Accumulated Depreciation & Amortization	(1,368,987)	0	(1,368,987)	76,804	(1,292,183)	0	(1,292,183)	115,150	(1,177,033)	0.9804976	(1,154,078)
3	Net Plant-in-Service (1) - (2)	2,679,848	0	2,679,848	(921,648)	1,758,200	0	1,758,200	(253,373)	1,504,827	0.9821468	1,477,961
4	Plant Held for Future Use	15,451	0	15,451	(10,016)	5,435	0	5,435	0	5,435	0.9707452	5,276
5	Construction Work-in-Progress	214,726	0	214,726	(160,443)	54,283	0	54,283	(3,840)	50,443	0.9767680	49,271
6	Plant Acquisition Adjustment	2,414	0	2,414	0	2,414	0	2,414	(2,414)	0		0
7	Net Utility Plant (3)+(4)+(5)+(6)	2,912,439	0	2,912,439	(1,092,107)	1,820,332	0	1,820,332	(259,627)	1,560,705	0.9819332	1,532,508
8	Working Capital Allowance	215,545	(13,218)	202,327	(3,786)	198,541	0	198,541	(12,190)	186,351	0.9769414	182,054
9	Total Rate Base (7) + (8)	3,127,984	(13,218)	3,114,766	(1,095,893)	2,018,873	0	2,018,873	(271,817)	1,747,056		1,714,562

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: List and explain all proposed adjustments to the 13-month average rate base for the test year, the prior year and the most recent historical year. List the adjustments included in the last case that are not proposed in the current case and the reasons for excluding them.

Type of Data Shown:
X Projected Test Year Ended 12/31/14
____Prior Year Ended 12/31/13
____Historical Year Ended 12/31/12
Witness: S. D. Ritenour

(1) Line No.	(2) Adj. No.	(3) Adjustment Title	(4) Reason for Adjustment or Omission	(5) Adjustment Amount ($000's)	(6) Jurisdictional Factor	(7) Jurisdictional Amount of Adjustment (5) x (6) ($000's)
1		Non Electric Adjustment:				
2		Working Capital Adjustments				
3	(1)	Non-Utility Plant	To remove the non-utility plant included in rate base.	(13,029)	1.0000000	(13,029)
4		Total Non Electric Adjustment		(13,029)		(13,029)
5		Commission Adjustments:				
6		Plant in Service Adjustments				
7	(2)	Plant-in-Service - Environmental Cost Recovery Clause	To exclude plant amounts associated with the Environmental Cost Recovery Clause.	(1,060,314)	0.9702233	(1,028,741)
9	(3)	Plant-in-Service - Conservation Cost Recovery Clause	To exclude plant amounts associated with the Energy Conservation Cost Recovery Clause.	(14,764)	1.0000000	(14,764)
11	(4)	Plant-in-Service - AROs	To exclude plant amounts associated with the Asset Retirement Obligations.	(8,037)	0.9706671	(7,801)
13		Accumulated Depreciation & Amortization Adjustments				
14	(5)	Depreciation Reserve - Environmental Cost Recovery Clause	To exclude plant amounts associated with the Environmental Cost Recovery Clause.	166,377	0.9702219	161,423
16	(6)	Depreciation Reserve - Conservation Cost Recovery Clause	To exclude plant amounts associated with the Energy Conservation Cost Recovery Clause.	(3,586)	1.0000000	(3,586)
18	(7)	Depreciation Reserve - AROs	To exclude plant amounts associated with the Asset Retirement Obligations.	(11,479)	0.9699795	(11,134)

FLORIDA PUBLIC SERVICE COMMISSION

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Type of Data Shown:
X Projected Test Year Ended 12/31/14
____ Prior Year Ended 12/31/13
____ Historical Year Ended 12/31/12
Witness: S. D. Ritenour

(1) Line No.	(2) Adj. No.	(3) Adjustment Title	(4) Reason for Adjustment or Omission	(5) Adjustment Amount ($000's)	(6) Jurisdictional Factor	(7) Jurisdictional Amount of Adjustment (5) x (6) ($000's)
1		Commission Adjustments Continued:				
2		Construction Work In Progress Adjustments				
3	(8)	CWIP - Interest Bearing	To exclude from rate base CWIP eligible for AFUDC.	(312,857)	0.9767680	(305,589)
4	(9)	CWIP - Environmental Cost Recovery Clause	To exclude plant amounts associated with the	(62,698)	0.9701895	(60,829)
5			Environmental Cost Recovery Clause.			
6		Plant Held for Future Use Adjustments				
7	(10)	Decrease Plant Held for Future Use	Adjustment to exclude from rate base costs	(13,021)	0.9702652	(12,634)
8			associated with the North Escambia site.			
9		Working Capital Adjustments				
10	(11)	Commission Working Capital Adjusments	To remove from working capital the effects of	8,872	0.9737364	8,639
11		(see MFR B-17 for details)	Commission adjustments.			
12		Total Commission Adjustments		(1,311,507)		(1,275,016)
13		Company Adjustments				
14		Plant In Service Adjustments				
15	(12)	Plant-in-Service - Perdido Unit 3	To exclude plant amounts associated with	(4,460)	0.9701832	(4,327)
16			Perdido Unit 3.			
17	(13)	Plant-in-Service - Distribution New Business	To exclude plant amounts associated with	(2,068)	0.9999470	(2,068)
18			distribution capital expenditures.			

FLORIDA PUBLIC SERVICE COMMISSION

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Type of Data Shown:
X Projected Test Year Ended 12/31/14
____ Prior Year Ended 12/31/13
____ Historical Year Ended 12/31/12
Witness: S. D. Ritenour

(1) Line No.	(2) Adj. No.	(3) Adjustment Title	(4) Reason for Adjustment or Omission	(5) Adjustment Amount ($000's)	(6) Jurisdictional Factor	(7) Jurisdictional Amount of Adjustment (5) x (6) ($000's)
1		Company Adjustments Continued:				
2		Accumulated Depreciation & Amortization Adjustments				
3	(14)	Decrease in Accumulated Reserve - Perdido Unit 3	Adjustment to decrease the accumulated reserve related to Perdido Unit 3.	127	0.9701838	123
4						
5	(15)	Accumulated Depreciation: 2013 Depreciation Study	Adjustment to decrease the accumulated reserve related to the 2013 depreciation study.	43	Various	62
6						
7	(16)	Accumulated Depreciation : Distribution New Business	Adjustment to decrease the accumulated reserve related to distribution capital expenditures.	22	0.9999456	22
8						
9		Working Capital Adjustments				
10	(17)	Company Working Capital Adjustments	To remove from working capital the effects of Company adjustments.	(2,750)	0.9737364	(2,678)
11		(see MFR B-17 for details)				
12		Total Company Adjustments		(9,086)		(8,866)
13		Total Rate Base Adjustments		(1,320,593)		(1,283,882)

FLORIDA PUBLIC SERVICE COMMISSION

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DOCKET NO.: 130140-EI

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Type of Data Shown:
__X__Projected Test Year Ended 12/31/14
_____Prior Year Ended 12/31/13
_____Historical Year Ended 12/31/12
Witness: S. D. Ritenour

(1)	(2)	(3)
Line No.	Adjustment Title	Reason for Adjustment or Omission
1	Adjustments Not Made:	
2	Plant Crist 6 & 7 Turbine Upgrades	Adjustment is not applicable for the 2014 test year.
3 4	Capitalized Incentive Compensation	As discussed in testimony, Gulf believes that incentive compensation is properly included in jurisdictional rate base.
5	Distribution Plant	Adjustment is not applicable for the 2014 test year.
6	Non-AMI Meter Amortization	Adjustment is not applicable for the 2014 test year.
7	Plant-Related Reclassifications	Adjustment is not applicable for the 2014 test year.
8	Fuel Inventories	Adjustment is not applicable for the 2014 test year.
9	ECCR Adjustment Error	Adjustment is not applicable for the 2014 test year.
10	AMI Meter Depreciation	Adjustment is not applicable for the 2014 test year.
11	Working Capital - Pensions & Other OPRBs	Adjustment is not applicable for the 2014 test year.

FLORIDA PUBLIC SERVICE COMMISSION

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Type of Data Shown:
____Projected Test Year Ended 12/31/14
_X_Prior Year Ended 12/31/13
____Historical Year Ended 12/31/12
Witness: S. D. Ritenour

(1) Line No.	(2) Adj. No.	(3) Adjustment Title	(4) Reason for Adjustment or Omission	(5) Adjustment Amount ($000's)	(6) Jurisdictional Factor	(7) Jurisdictional Amount of Adjustment (5) x (6) ($000's)
1		Non Electric Adjustment:				
2		Working Capital Adjustments				
3	(1)	Non-Utility Plant	To remove the non-utility plant included in rate base.	(13,050)	1.0000000	(13,050)
4		Total Non Electric Adjustment		(13,050)		(13,050)
5		Commission Adjustments:				
6		Plant in Service Adjustments				
7	(2)	Plant-in-Service - Environmental Cost Recovery Clause	To exclude plant amounts associated with the Environmental Cost Recovery Clause.	(1,052,445)	0.9702233	(1,021,107)
9	(3)	Plant-in-Service - Conservation Cost Recovery Clause	To exclude plant amounts associated with the Energy Conservation Cost Recovery Clause.	(12,049)	1.0000000	(12,049)
11	(4)	Plant-in-Service - AROs	To exclude plant amounts associated with the Asset Retirement Obligations.	(8,037)	0.9706671	(7,801)
13		Accumulated Depreciation & Amortization Adjustments				
14	(5)	Depreciation Reserve - Environmental Cost Recovery Clause	To exclude plant amounts associated with the Environmental Cost Recovery Clause.	126,996	0.9702219	123,214
16	(6)	Depreciation Reserve - Conservation Cost Recovery Clause	To exclude plant amounts associated with the Energy Conservation Cost Recovery Clause.	(3,960)	1.0000000	(3,960)
18	(7)	Depreciation Reserve - AROs	To exclude plant amounts associated with the Asset Retirement Obligations.	(11,479)	0.9699795	(11,134)

FLORIDA PUBLIC SERVICE COMMISSION

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Type of Data Shown:
____Projected Test Year Ended 12/31/14
__X__Prior Year Ended 12/31/13
____Historical Year Ended 12/31/12
Witness: S. D. Ritenour

(1) Line No.	(2) Adj. No.	(3) Adjustment Title	(4) Reason for Adjustment or Omission	(5) Adjustment Amount ($000's)	(6) Jurisdictional Factor	(7) Jurisdictional Amount of Adjustment (5) x (6) ($000's)
1		Commission Adjustments Continued:				
2		Construction Work In Progress Adjustments				
3	(8)	CWIP - Interest Bearing	To exclude from rate base CWIP eligible for AFUDC.	(160,600)	0.9767680	(156,869)
4	(9)	CWIP - Environmental Cost Recovery Clause	To exclude plant amounts associated with the	(2,240)	0.9701895	(2,173)
5			Environmental Cost Recovery Clause.			
6		Plant Held for Future Use Adjustments				
7	(10)	Decrease Plant Held for Future Use	Adjustment to exclude from rate base costs	(13,021)	0.9702652	(12,634)
8			associated with the North Escambia site.			
9		Working Capital Adjustments				
10	(11)	Commission Working Capital Adjustments	To remove from working capital the effects of	5,359	0.9739900	5,220
11		(see MFR B-17 for details)	Commission adjustments.			
12		Total Commission Adjustments		(1,131,476)		(1,099,293)
13		Total Rate Base Adjustments		(1,131,476)		(1,099,293)

FLORIDA PUBLIC SERVICE COMMISSION

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DOCKET NO.: 130140-EI

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Type of Data Shown:
____Projected Test Year Ended 12/31/14
_X__Prior Year Ended 12/31/13
____Historical Year Ended 12/31/12
Witness: S. D. Ritenour

(1) Line No.	(2) Adj. No.	(3) Adjustment Title	(4) Reason for Adjustment or Omission	(5) Adjustment Amount ($000's)	(6) Jurisdictional Factor	(7) Jurisdictional Amount of Adjustment (5) x (6) ($000's)
1		Adjustments Not Made:				
2		Plant Crist 6 & 7 Turbine Upgrades	Adjustment is not applicable for the 2013 year.			
3 4		Capitalized Incentive Compensation	As discussed in testimony, Gulf believes that incentive compensation is properly included in jurisdictional rate base.			
5		Distribution Plant	Adjustment is not applicable for the 2013 year.			
6		Non-AMI Meter Amortization	Adjustment is not applicable for the 2013 year.			
7		Plant-Related Reclassifications	Adjustment is not applicable for the 2013 year.			
8		Fuel Inventories	Adjustment is not applicable for the 2013 year.			
9		ECCR Adjustment Error	Adjustment is not applicable for the 2013 year.			
10		AMI Meter Depreciation	Adjustment is not applicable for the 2013 year.			
11		Working Capital - Pensions & Other OPRBs	Adjustment is not applicable for the 2013 year.			

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FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: List and explain all proposed adjustments to the 13-month average rate base for the test year, the prior year and the most recent historical year. List the adjustments included in the last case that are not proposed in the current case and the reasons for excluding them.

Type of Data Shown:
____Projected Test Year Ended 12/31/14
____Prior Year Ended 12/31/13
X Historical Year Ended 12/31/12
Witness: S. D. Ritenour

(1) Line No.	(2) Adj. No.	(3) Adjustment Title	(4) Reason for Adjustment or Omission	(5) Adjustment Amount ($000's)	(6) Jurisdictional Factor	(7) Jurisdictional Amount of Adjustment (5) x (6) ($000's)
1		Non Electric Adjustment:				
2		Working Capital Adjustments				
3	(1)	Non-Utility Plant	To remove the non-utility plant included in rate base.	(13,218)	1.0000000	(13,218)
4		Total Non Electric Adjustment		(13,218)		(13,218)
5		Commission Adjustments:				
6		Plant in Service Adjustments				
7	(2)	Plant-in-Service - Environmental Cost Recovery Clause	To exclude plant amounts associated with the Environmental Cost Recovery Clause.	(984,517)	0.9702233	(955,201)
9	(3)	Plant-in-Service - Conservation Cost Recovery Clause	To exclude plant amounts associated with the Energy Conservation Cost Recovery Clause.	(10,439)	1.0000000	(10,439)
11	(4)	Plant-in-Service - AROs	To exclude plant amounts associated with the Asset Retirement Obligations.	(3,496)	0.9706671	(3,393)
13		Accumulated Depreciation & Amortization Adjustments				
14	(5)	Depreciation Reserve - Environmental Cost Recovery Clause	To exclude plant amounts associated with the Environmental Cost Recovery Clause.	91,311	0.9702219	88,592
16	(6)	Depreciation Reserve - Conservation Cost Recovery Clause	To exclude plant amounts associated with the Energy Conservation Cost Recovery Clause.	(2,987)	1.0000000	(2,987)
18	(7)	Depreciation Reserve - AROs	To exclude plant amounts associated with the Asset Retirement Obligations.	(11,520)	0.9699795	(11,174)

Supporting Schedules: B-6, B-17

Recap Schedules: B-1

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: List and explain all proposed adjustments to the 13-month average rate base for the test year, the prior year and the most recent historical year. List the adjustments included in the last case that are not proposed in the current case and the reasons for excluding them.

Type of Data Shown:
____Projected Test Year Ended 12/31/14
____Prior Year Ended 12/31/13
X Historical Year Ended 12/31/12
Witness: S. D. Ritenour

(1) Line No.	(2) Adj. No.	(3) Adjustment Title	(4) Reason for Adjustment or Omission	(5) Adjustment Amount ($000's)	(6) Jurisdictional Factor	(7) Jurisdictional Amount of Adjustment (5) x (6) ($000's)
1		Commission Adjustments Continued:				
2		Construction Work In Progress Adjustments				
3	(8)	CWIP - Interest Bearing	To exclude from rate base CWIP eligible for AFUDC.	(156,245)	0.9767680	(152,615)
4	(9)	CWIP - Environmental Cost Recovery Clause	To exclude plant amounts associated with the	(4,198)	0.9701895	(4,073)
5			Environmental Cost Recovery Clause.			
6		Plant Held for Future Use Adjustments				
7	(10)	Decrease Plant Held for Future Use	Adjustment to exclude from rate base costs	(10,016)	0.9702652	(9,718)
8			associated with the North Escambia site.			
9		Working Capital Adjustments				
10	(11)	Commission Working Capital Adjustments	To remove from working capital the effects of	(3,786)	0.9769414	(3,699)
11		(see MFR B-17 for details)	Commission adjustments.			
12		Total Commission Adjustments		(1,095,893)		(1,064,707)
13		Total Rate Base Adjustments		(1,095,893)		(1,064,707)

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: List and explain all proposed adjustments to the 13-month average rate base for the test year, the prior year and the most recent historical year. List the adjustments included in the last case that are not proposed in the current case and the reasons for excluding them.

Type of Data Shown:
____Projected Test Year Ended 12/31/14
____Prior Year Ended 12/31/13
_X_Historical Year Ended 12/31/12
Witness: S. D. Ritenour

(1) Line No.	(2) Adj. No.	(3) Adjustment Title	(4) Reason for Adjustment or Omission	(5) Adjustment Amount ($000's)	(6) Jurisdictional Factor	(7) Jurisdictional Amount of Adjustment (5) x (6) ($000's)
1		Adjustments Not Made:				
2		Plant Crist 6 & 7 Turbine Upgrades	Adjustment is not applicable for the 2012 year.			
3 4		Capitalized Incentive Compensation	As discussed in testimony, Gulf believes that incentive compensation is properly included in jurisdictional rate base.			
5		Distribution Plant	Adjustment is not applicable for the 2012 year.			
6		Non-AMI Meter Amortization	Adjustment is not applicable for the 2012 year.			
7		Plant-Related Reclassifications	Adjustment is not applicable for the 2012 year.			
8		Fuel Inventories	Adjustment is not applicable for the 2012 year.			
9		ECCR Adjustment Error	Adjustment is not applicable for the 2012 year.			
10		AMI Meter Depreciation	Adjustment is not applicable for the 2012 year.			
11		Working Capital - Pensions & Other OPRBs	Adjustment is not applicable for the 2012 year.			

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Derive the 13-month average system balance sheet by primary account by month for the test year, the prior year, and the most recent historical year. For accounts including non-electric utility amounts, show these amounts as a separate subaccount.

Type of Data Shown:
X Projected Test Year Ended 12/31/14
_ Prior Year Ended 12/31/13
_ Historical Year Ended 12/31/12
Witness: S. D. Ritenour

($000's)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
Line No.	Account No.	Account Name	12/2013	1/2014	2/2014	3/2014	4/2014	5/2014	6/2014	7/2014
1		Utility Plant								
2	101	Electric Plant In Service	4,426,718	4,429,469	4,437,303	4,449,503	4,457,456	4,464,767	4,476,152	4,484,091
3	105	Plant Held for Future Use	18,456	18,456	18,456	18,456	18,456	18,456	18,456	18,456
4	106	Plant In Service Unclassified	0	0	0	0	0	0	0	0
5	107	Construction Work in Progress	242,066	275,495	305,098	335,324	366,405	390,879	412,222	436,360
6	108	Accum Prov for Depreciation	(1,456,207)	(1,467,600)	(1,476,931)	(1,486,704)	(1,497,388)	(1,508,857)	(1,520,148)	(1,531,120)
7	111	Accum Prov for Amortization	(29,054)	(27,782)	(26,960)	(27,446)	(27,933)	(28,420)	(28,907)	(29,394)
8	114	Electric Plant Acquistion Adjustments	2,031	2,010	1,988	1,967	1,946	1,925	1,903	1,882
9		Total Utility Plant	3,204,010	3,230,048	3,258,955	3,291,100	3,318,941	3,338,749	3,359,679	3,380,275
10		Other Property and Investments								
11	121	Non-Utility Property	15,829	15,843	15,856	15,869	15,882	15,896	15,909	15,922
12	122	Accum Prov for Non-Utility Property	(2,774)	(2,792)	(2,809)	(2,827)	(2,844)	(2,862)	(2,879)	(2,897)
13	123	Investment in Associated Companies	2,588	2,589	2,590	2,592	2,593	2,595	2,597	2,598
14	128	Other Special Funds	101,452	102,543	101,786	101,029	100,278	99,528	98,777	98,034
15		Total Other Property and Investments	117,095	118,183	117,423	116,664	115,909	115,157	114,404	113,657

Totals may not add due to rounding.

Supporting Schedules: B-19, B-20

Recap Schedules: B-1

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Derive the 13-month average system balance sheet by primary account by month for the test year, the prior year, and the most recent historical year. For accounts including non-electric utility amounts, show these amounts as a separate subaccount.

Type of Data Shown:
X Projected Test Year Ended 12/31/14
_ Prior Year Ended 12/31/13
_ Historical Year Ended 12/31/12
Witness: S. D. Ritenour

($000's)

(1) Line No.	(2) Account No.	(3) Account Name	(4) 8/2014	(5) 9/2014	(6) 10/2014	(7) 11/2014	(8) 12/2014	(9) 13-Month Average	(10) Reference RB WC CS ORP NEU
1		Utility Plant							
2	101	Electric Plant In Service	4,490,490	4,497,642	4,504,026	4,512,025	4,619,703	4,480,719	RB
3	105	Plant Held for Future Use	18,456	18,456	18,456	18,456	18,456	18,456	RB
4	106	Plant In Service Unclassified	0	0	0	0	0	0	RB
5	107	Construction Work in Progress	461,902	492,381	529,773	568,889	505,433	409,402	RB
6	108	Accum Prov for Depreciation	(1,542,365)	(1,553,397)	(1,564,479)	(1,575,119)	(1,584,059)	(1,520,337)	RB
7	111	Accum Prov for Amortization	(29,880)	(30,367)	(30,854)	(31,340)	(31,411)	(29,211)	RB
8	114	Electric Plant Acquistion Adjustments	1,861	1,839	1,818	1,797	1,776	1,903	RB
9		Total Utility Plant	3,400,463	3,426,554	3,458,741	3,494,707	3,529,898	3,360,932	
10		Other Property and Investments							
11	121	Non-Utility Property	15,935	15,949	15,962	15,975	15,988	15,909	NEU
12	122	Accum Prov for Non-Utility Property	(2,915)	(2,933)	(2,951)	(2,969)	(2,987)	(2,880)	NEU
13	123	Investment In Associated Companies	2,600	2,603	2,606	2,609	2,612	2,598	NEU
14	128	Other Special Funds	97,292	96,549	95,813	95,077	94,341	98,654	WC
15		Total Other Property and Investments	112,913	112,168	111,430	110,693	109,955	114,281	

REFERENCE:
RB = Rate Base; WC = Working Capital; CS = Capital Structure; ORP = Other Return Provided; NEU = Non-Electric Utility
Totals may not add due to rounding.

Supporting Schedules: B-19, B-20

Recap Schedules: B-1

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Derive the 13-month average system balance sheet by primary account by month for the test year, the prior year, and the most recent historical year. For accounts including non-electric utility amounts, show these amounts as a separate subaccount.

Type of Data Shown:
X Projected Test Year Ended 12/31/14
_ Prior Year Ended 12/31/13
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Witness: S. D. Ritenour

($000's)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
Line No.	Account No.	Account Name	12/2013	1/2014	2/2014	3/2014	4/2014	5/2014	6/2014	7/2014
1		Current and Accrued Assets								
2	131	Cash	6,011	6,011	6,011	6,011	6,011	6,011	6,011	6,011
3	134	Other Special Deposits	18	18	18	18	18	18	18	18
4	135	Working Funds	378	378	379	379	378	378	378	379
5	136	Temporary Cash Investments	0	0	0	0	0	0	0	0
6	142	Customer Accounts Receivable	68,099	76,272	75,591	62,318	62,731	63,521	79,831	90,325
7	143	Other Accounts Receivable	9,651	9,651	9,651	9,651	9,651	9,651	9,651	9,651
8	144	Accum Prov for Uncollectible Accounts	(1,799)	(2,242)	(2,220)	(1,708)	(1,510)	(1,440)	(1,426)	(1,593)
9	146	Accounts Receivable from Assoc Companies	15,684	14,742	13,006	11,306	10,640	8,542	12,263	17,544
10	151	Fuel Stock	123,479	115,837	117,847	115,992	114,443	111,604	106,857	98,583
11	154 and 163	Plant Materials and Operating Supplies	53,609	53,513	53,437	53,346	53,253	53,152	53,479	54,093
12	158	Allowance Inventory	7,211	7,140	7,069	6,997	6,926	6,855	6,783	6,712
13	165	Prepayments	13,506	13,919	14,201	14,483	14,764	16,132	16,411	16,689
14	171	Interest and Dividends Receivable	9	15	16	16	23	23	23	30
15	172	Rents Receivable	2,208	3,497	3,352	3,206	3,061	2,916	2,771	2,937
16	173	Accrued Utility Revenues	54,079	52,567	43,950	44,696	44,641	59,262	64,950	67,807
17	174	Miscellaneous Current and Accrued Assets	0	0	0	0	0	0	0	0
18	175	Derivative Instrument Assets	0	0	0	0	0	0	0	0
19	176	Derivative Instrument Assets - Hedges	4,357	4,357	4,357	4,357	4,357	4,357	4,357	4,357
20		Total Current and Accrued Assets	356,500	355,675	346,685	331,070	329,387	340,982	362,357	373,543

Totals may not add due to rounding.

Supporting Schedules: B-19, B-20

Recap Schedules: B-1

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Derive the 13-month average system balance sheet by primary account by month for the test year, the prior year, and the most recent historical year. For accounts including non-electric utility amounts, show these amounts as a separate subaccount.

Type of Data Shown:
X Projected Test Year Ended 12/31/14
_ Prior Year Ended 12/31/13
_ Historical Year Ended 12/31/12
Witness: S. D. Ritenour

($000's)

(1) Line No.	(2) Account No.	(3) Account Name	(4) 8/2014	(5) 9/2014	(6) 10/2014	(7) 11/2014	(8) 12/2014	(9) 13-Month Average	(10) Reference RB WC CS ORP NEU
1		Current and Accrued Assets							
2	131	Cash	6,011	6,011	6,011	6,011	6,011	6,011	WC
3	134	Other Special Deposits	18	18	18	18	18	18	WC
4	135	Working Funds	378	378	379	379	379	378	WC
5	136	Temporary Cash Investments	0	0	0	0	0	0	WC
6	142	Customer Accounts Receivable	88,194	97,255	83,301	68,472	72,615	76,042	WC
7	143	Other Accounts Receivable	9,651	9,651	9,651	9,651	9,651	9,651	WC
8	144	Accum Prov for Uncollectible Accounts	(1,588)	(1,933)	(1,768)	(1,478)	(1,910)	(1,740)	WC
9	146	Accounts Receivable from Assoc Companies	20,586	16,009	10,299	12,289	10,946	13,374	WC
10	151	Fuel Stock	92,155	87,928	84,103	85,309	87,839	103,229	WC
11	154 and 163	Plant Materials and Operating Supplies	53,969	53,849	53,742	53,657	53,599	53,593	WC
12	158	Allowance Inventory	6,641	6,569	6,498	6,427	6,355	6,783	WC
13	165	Prepayments	17,062	17,341	17,619	22,575	22,838	16,734	WC
14	171	Interest and Dividends Receivable	31	31	37	37	37	25	WC
15	172	Rents Receivable	2,791	2,645	2,500	2,354	2,208	2,804	WC
16	173	Accrued Utility Revenues	68,224	58,458	47,235	49,618	54,870	54,643	WC
17	174	Miscellaneous Current and Accrued Assets	0	0	0	0	0	0	WC
18	175	Derivative Instrument Assets	0	0	0	0	0	0	WC
19	176	Derivative Instrument Assets - Hedges	4,357	4,357	4,357	4,357	4,357	4,357	WC
20		Total Current and Accrued Assets	368,480	358,567	323,982	319,676	329,813	345,902	

REFERENCE:
RB = Rate Base; WC = Working Capital; CS = Capital Structure; ORP = Other Return Provided; NEU = Non-Electric Utility
Totals may not add due to rounding.

Supporting Schedules: B-19, B-20

Recap Schedules: B-1

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FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Derive the 13-month average system balance sheet by primary account by month for the test year, the prior year, and the most recent historical year. For accounts including non-electric utility amounts, show these amounts as a separate subaccount.

Type of Data Shown:
X Projected Test Year Ended 12/31/14
_ Prior Year Ended 12/31/13
_ Historical Year Ended 12/31/12
Witness: S. D. Ritenour

($000's)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
Line No.	Account No.	Account Name	12/2013	1/2014	2/2014	3/2014	4/2014	5/2014	6/2014	7/2014
1		Deferred Debits								
2	181	Unamortized Debt Expense	7,721	7,677	7,632	7,588	7,543	7,499	7,454	7,410
3	182	Regulatory Assets	497,673	501,582	505,491	509,055	512,964	516,873	515,056	513,584
4	183	Prelim Site Investigation Costs	10,460	10,470	10,480	10,490	10,500	7,868	7,878	7,888
5	184	Clearing Accounts	0	0	0	0	0	0	0	0
6	185	Temporary Facilities	0	0	0	0	0	0	0	0
7	186	Miscellaneous Deferred Debits	8,921	7,361	5,802	4,144	2,486	1,419	1,419	1,419
8	188	Research, Development, and Demo Expense	0	150	75	0	150	75	0	150
9	189	Unamortized Loss on Reacquired Debt	15,048	14,937	14,827	14,717	14,607	14,497	14,386	14,276
10	190	Accumulated Deferred Income Tax	74,155	74,565	74,975	75,385	75,795	76,205	76,615	77,025
11		Total Deferred Debits	613,978	616,742	619,282	621,379	624,045	624,436	622,808	621,752
12		Total Assets and Other Debits	4,291,583	4,320,648	4,342,325	4,360,213	4,388,282	4,419,324	4,459,248	4,489,227

Totals may not add due to rounding.

Supporting Schedules: B-19, B-20

Recap Schedules: B-1

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

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Witness: S. D. Ritenour

($000's)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Line No.	Account No.	Account Name	8/2014	9/2014	10/2014	11/2014	12/2014	13-Month Average	Reference RB WC CS ORP NEU
1		Deferred Debits							
2	181	Unamortized Debt Expense	7,365	7,321	7,278	7,235	7,192	7,455	CS
3	182	Regulatory Assets	512,112	510,296	508,824	507,352	505,825	508,976	WC
4	183	Prelim Site Investigation Costs	7,898	7,908	7,918	7,928	7,938	8,894	WC
5	184	Clearing Accounts	0	0	0	0	0	0	WC
6	185	Temporary Facilities	0	0	0	0	0	0	WC
7	186	Miscellaneous Deferred Debits	1,419	1,419	1,419	1,419	1,419	3,082	WC
8	188	Research, Development, and Demo Expense	75	0	150	75	0	69	WC
9	189	Unamortized Loss on Reacquired Debt	14,166	14,056	13,946	13,836	13,732	14,387	CS
10	190	Accumulated Deferred Income Tax	77,435	77,845	78,255	78,665	79,075	76,615	CS
11		Total Deferred Debits	620,470	618,845	617,790	616,510	615,181	619,478	
12		Total Assets and Other Debits	4,502,326	4,516,134	4,511,943	4,541,586	4,584,847	4,440,593	

REFERENCE:
RB = Rate Base; WC = Working Capital; CS = Capital Structure; ORP = Other Return Provided; NEU = Non-Electric Utility
Totals may not add due to rounding.

Supporting Schedules: B-19, B-20

Recap Schedules: B-1

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Derive the 13-month average system balance sheet by primary account by month for the test year, the prior year, and the most recent historical year. For accounts including non-electric utility amounts, show these amounts as a separate subaccount.

Type of Data Shown:
X Projected Test Year Ended 12/31/14
_ Prior Year Ended 12/31/13
_ Historical Year Ended 12/31/12
Witness: S. D. Ritenour

($000's)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
Line No.	Account No.	Account Name	12/2013	1/2014	2/2014	3/2014	4/2014	5/2014	6/2014	7/2014
1		Proprietary Capital								
2	201	Common Stock Issued	(393,060)	(393,060)	(393,060)	(393,060)	(393,060)	(393,060)	(393,060)	(393,060)
3	204	Preferred Stock Issued	(150,000)	(150,000)	(150,000)	(150,000)	(150,000)	(150,000)	(150,000)	(150,000)
4	211	Miscellaneous Paid-In Capital	(597,891)	(718,759)	(718,978)	(721,088)	(721,195)	(721,307)	(722,736)	(722,844)
5	214	Capital Stock Expense	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002
6	216	Unappropriated Retained Earnings	(244,364)	(223,890)	(227,819)	(232,528)	(206,210)	(215,250)	(229,230)	(216,327)
7	219	Accumulated Other Comprehensive Income	1,109	1,078	1,047	1,016	985	954	923	892
8		Total Proprietary Capital	(1,382,204)	(1,482,629)	(1,486,808)	(1,493,658)	(1,467,478)	(1,476,661)	(1,492,101)	(1,479,337)
9		Long Term Debt								
10	224	Other Long Term Debt	(1,248,955)	(1,248,955)	(1,248,955)	(1,248,955)	(1,318,955)	(1,318,955)	(1,318,955)	(1,318,955)
11	226	Unamortized Premium on Long Term Debt	7,498	7,451	7,404	7,356	7,309	7,262	7,215	7,167
12		Total Long Term Debt	(1,241,457)	(1,241,504)	(1,241,551)	(1,241,599)	(1,311,646)	(1,311,693)	(1,311,740)	(1,311,788)
13		Other Non-Current Liabilities								
14	228	Miscellaneous Operating Provisions	(262,590)	(263,035)	(263,460)	(263,886)	(264,317)	(264,748)	(265,181)	(265,620)
15	229	Prov for Rate Refunds	0	0	0	0	0	0	0	0
16	230	Asset Retirement Obligations	(16,055)	(16,055)	(16,055)	(16,055)	(16,055)	(16,055)	(16,055)	(16,055)
17		Total Other Non-Current Liabilities	(278,645)	(279,090)	(279,515)	(279,941)	(280,372)	(280,803)	(281,236)	(281,675)

Totals may not add due to rounding.

Supporting Schedules: B-19, B-20

Recap Schedules: B-1

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Derive the 13-month average system balance sheet by primary account by month for the test year, the prior year, and the most recent historical year. For accounts including non-electric utility amounts, show these amounts as a separate subaccount.

Type of Data Shown:
X Projected Test Year Ended 12/31/14
_ Prior Year Ended 12/31/13
_ Historical Year Ended 12/31/12
Witness: S. D. Ritenour

($000's)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Line No.	Account No.	Account Name	8/2014	9/2014	10/2014	11/2014	12/2014	13-Month Average	Reference RB WC CS ORP NEU
1		Proprietary Capital							
2	201	Common Stock Issued	(393,060)	(393,060)	(393,060)	(393,060)	(393,060)	(393,060)	CS
3	204	Preferred Stock Issued	(150,000)	(150,000)	(150,000)	(150,000)	(150,000)	(150,000)	CS
4	211	Miscellaneous Paid-In Capital	(722,951)	(724,375)	(724,479)	(724,529)	(725,950)	(712,852)	CS
5	214	Capital Stock Expense	2,002	2,002	2,002	2,002	2,002	2,002	CS
6	216	Unappropriated Retained Earnings	(233,142)	(245,931)	(220,489)	(224,274)	(231,360)	(226,986)	CS
7	219	Accumulated Other Comprehensive Income	861	830	799	768	737	923	CS
8		Total Proprietary Capital	(1,496,290)	(1,510,534)	(1,485,227)	(1,489,093)	(1,497,631)	(1,479,973)	
9		Long Term Debt							
10	224	Other Long Term Debt	(1,318,955)	(1,318,955)	(1,383,955)	(1,383,955)	(1,383,955)	(1,312,417)	CS
11	226	Unamortized Premium on Long Term Debt	7,120	7,073	7,030	6,967	6,944	7,217	CS
12		Total Long Term Debt	(1,311,835)	(1,311,882)	(1,376,925)	(1,376,968)	(1,377,011)	(1,305,200)	
13		Other Non-Current Liabilities							
14	228	Miscellaneous Operating Provisions	(266,058)	(266,514)	(266,960)	(267,405)	(267,853)	(265,202)	WC
15	229	Prov for Rate Refunds	0	0	0	0	0	0	WC
16	230	Asset Retirement Obligations	(16,055)	(16,055)	(16,055)	(16,055)	(16,055)	(16,055)	WC
17		Total Other Non-Current Liabilities	(282,113)	(282,569)	(283,015)	(283,460)	(283,908)	(281,257)	

REFERENCE:
RB = Rate Base; WC = Working Capital; CS = Capital Structure; ORP = Other Return Provided; NEU = Non-Electric Utility
Totals may not add due to rounding.

Supporting Schedules: B-19, B-20

Recap Schedules: B-1

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Derive the 13-month average system balance sheet by primary account by month for the test year, the prior year, and the most recent historical year. For accounts including non-electric utility amounts, show these amounts as a separate subaccount.

Type of Data Shown:
X Projected Test Year Ended 12/31/14
_ Prior Year Ended 12/31/13
_ Historical Year Ended 12/31/12
Witness: S. D. Ritenour

($000's)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
Line No.	Account No.	Account Name	12/2013	1/2014	2/2014	3/2014	4/2014	5/2014	6/2014	7/2014
1		Current and Accrued Liabilities								
2	231	Notes Payable	0	0	0	0	0	0	0	0
3	232	Accounts Payable	(67,011)	(76,472)	(72,075)	(73,776)	(72,561)	(69,863)	(70,187)	(69,896)
4	233	Notes Payable to Associated Companies	(119,499)	(3,321)	(17,213)	(61,364)	(19,848)	(21,280)	(73,858)	(62,364)
5	234	Accounts Payable to Associated Companies	(42,841)	(37,132)	(31,721)	(31,752)	(30,293)	(36,222)	(38,356)	(47,485)
6	235	Customer Deposits	(35,075)	(35,136)	(35,191)	(35,239)	(35,286)	(35,334)	(35,396)	(35,441)
7	236	Taxes Accrued	(4,937)	(7,973)	(10,723)	(13,689)	(7,939)	(10,186)	(18,296)	(29,094)
8	237	Interest Accrued	(9,290)	(12,603)	(16,404)	(13,555)	(11,870)	(16,258)	(9,912)	(12,571)
9	238	Dividends Declared	(2,196)	(30,856)	(31,596)	(2,196)	(30,856)	(31,596)	(2,196)	(30,856)
10	241	Tax Collections Payable	(1,242)	438	159	92	(1,301)	(5,416)	(1,025)	(2,071)
11	242	Miscellaneous Current and Accrued Liabilities	(29,274)	(30,868)	(32,000)	(21,907)	(23,060)	(23,583)	(24,604)	(25,622)
12	244	Derivative Instrument Liabilities	0	0	0	0	0	0	0	0
13	245	Derivative Instrument Liabilities - Hedges	(27,112)	(27,112)	(27,112)	(27,112)	(27,112)	(27,112)	(27,112)	(27,112)
14		Total Current and Accrued Liabilities	(338,477)	(261,035)	(273,876)	(280,498)	(260,146)	(276,850)	(300,942)	(342,512)
15		Deferred Credits								
16	253	Other Deferred Credits	(247,649)	(252,444)	(255,832)	(259,076)	(262,501)	(265,888)	(263,444)	(261,774)
17	254	Regulatory Liabilities	(30,906)	(29,231)	(27,556)	(25,782)	(24,008)	(22,826)	(22,710)	(22,594)
18	255	Accumulated Deferred Investment Tax Credits	(4,106)	(4,002)	(3,900)	(3,798)	(3,696)	(3,594)	(3,492)	(3,390)
19	281	Accumulated Deferred Income Taxes	(161,104)	(162,818)	(164,532)	(166,246)	(167,960)	(169,674)	(171,388)	(173,102)
20	282	Accumulated Deferred Income Taxes	(549,275)	(550,287)	(551,299)	(552,311)	(553,323)	(554,335)	(555,347)	(556,359)
21	283	Accumulated Deferred Income Taxes	(57,760)	(57,608)	(57,456)	(57,304)	(57,152)	(57,000)	(56,848)	(56,696)
22		Total Deferred Credits	(1,050,800)	(1,056,390)	(1,060,575)	(1,064,517)	(1,068,640)	(1,073,317)	(1,073,229)	(1,073,915)
23		Total Liabilities and Capital	(4,291,583)	(4,320,648)	(4,342,325)	(4,360,213)	(4,388,282)	(4,419,324)	(4,459,248)	(4,489,227)

Totals may not add due to rounding.

Supporting Schedules: B-19, B-20

Recap Schedules: B-1

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Derive the 13-month average system balance sheet by primary account by month for the test year, the prior year, and the most recent historical year. For accounts including non-electric utility amounts, show these amounts as a separate subaccount.

Type of Data Shown:
X Projected Test Year Ended 12/31/14
_ Prior Year Ended 12/31/13
_ Historical Year Ended 12/31/12
Witness: S. D. Ritenour

($000's)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Line No.	Account No.	Account Name	8/2014	9/2014	10/2014	11/2014	12/2014	13-Month Average	Reference RB WC CS ORP NEU
1		Current and Accrued Liabilities							
2	231	Notes Payable	0	0	0	0	0	0	CS
3	232	Accounts Payable	(70,797)	(70,883)	(79,155)	(79,461)	(73,130)	(72,713)	WC
4	233	Notes Payable to Associated Companies	(44,240)	(82,705)	(3,467)	(38,293)	(124,165)	(51,663)	CS
5	234	Accounts Payable to Associated Companies	(42,139)	(40,502)	(36,221)	(38,333)	(41,155)	(38,012)	WC
6	235	Customer Deposits	(35,476)	(35,477)	(35,482)	(35,498)	(35,519)	(35,350)	CS
7	236	Taxes Accrued	(39,937)	(39,788)	(46,073)	(13,102)	(5,413)	(19,012)	WC
8	237	Interest Accrued	(16,801)	(14,247)	(12,007)	(16,741)	(11,650)	(13,378)	WC
9	238	Dividends Declared	(31,596)	(2,196)	(30,856)	(31,596)	(2,196)	(20,061)	CS
10	241	Tax Collections Payable	(3,073)	2,331	5,387	(8,758)	(1,361)	(1,218)	WC
11	242	Miscellaneous Current and Accrued Liabilities	(26,639)	(26,363)	(27,288)	(28,307)	(29,881)	(26,879)	WC
12	244	Derivative Instrument Liabilities	0	0	0	0	0	0	WC
13	245	Derivative Instrument Liabilities - Hedges	(27,112)	(27,112)	(27,112)	(27,112)	(27,112)	(27,112)	WC
14		Total Current and Accrued Liabilities	(337,810)	(336,942)	(292,274)	(317,201)	(351,582)	(305,398)	
15		Deferred Credits							
16	253	Other Deferred Credits	(259,780)	(257,353)	(255,291)	(253,297)	(250,785)	(257,316)	WC
17	254	Regulatory Liabilities	(22,479)	(22,363)	(22,248)	(22,132)	(22,016)	(24,373)	WC
18	255	Accumulated Deferred Investment Tax Credits	(3,288)	(3,186)	(3,084)	(2,982)	(2,880)	(3,492)	CS
19	281	Accumulated Deferred Income Taxes	(174,816)	(176,530)	(178,244)	(179,958)	(181,679)	(171,389)	CS
20	282	Accumulated Deferred Income Taxes	(557,371)	(558,383)	(559,395)	(560,407)	(561,419)	(555,347)	CS
21	283	Accumulated Deferred Income Taxes	(56,544)	(56,392)	(56,240)	(56,088)	(55,936)	(56,848)	CS
22		Total Deferred Credits	(1,074,278)	(1,074,207)	(1,074,502)	(1,074,864)	(1,074,715)	(1,068,765)	
23		Total Liabilities and Capital	(4,502,326)	(4,516,134)	(4,511,943)	(4,541,586)	(4,584,847)	(4,440,593)	

REFERENCE:
RB = Rate Base; WC = Working Capital; CS = Capital Structure; ORP = Other Return Provided; NEU = Non-Electric Utility
Totals may not add due to rounding.

Supporting Schedules: B-19, B-20

Recap Schedules: B-1

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Derive the 13-month average system balance sheet by primary account by month for the test year, the prior year, and the most recent historical year. For accounts including non-electric utility amounts, show these amounts as a separate subaccount.

Type of Data Shown:
_ Projected Test Year Ended 12/31/14
X Prior Year Ended 12/31/13
_ Historical Year Ended 12/31/12
Witness: S. D. Ritenour

($000's)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
Line No.	Account No.	Account Name	12/2012	1/2013	2/2013	3/2013	4/2013	5/2013	6/2013	7/2013
1		Utility Plant								
2	101	Electric Plant In Service	3,875,337	4,255,881	4,262,618	4,273,146	4,285,434	4,301,806	4,316,717	4,342,900
3	105	Plant Held for Future Use	18,456	18,456	18,456	18,456	18,456	18,456	18,456	18,456
4	106	Plant In Service Unclassified	362,441	0	0	0	0	0	0	0
5	107	Construction Work in Progress	136,155	142,931	160,657	180,079	193,308	199,195	201,489	194,132
6	108	Accum Prov for Depreciation	(1,353,024)	(1,363,261)	(1,373,327)	(1,383,338)	(1,372,975)	(1,383,585)	(1,393,891)	(1,404,548)
7	111	Accum Prov for Amortization	(26,933)	(26,168)	(26,295)	(26,683)	(25,629)	(26,145)	(26,658)	(27,167)
8	114	Electric Plant Acquistion Adjustments	2,286	2,265	2,244	2,222	2,201	2,180	2,159	2,137
9		Total Utility Plant	3,014,718	3,030,104	3,044,353	3,063,882	3,100,795	3,111,907	3,118,272	3,125,910
10		Other Property and Investments								
11	121	Non-Utility Property	15,744	15,642	15,643	15,644	15,673	15,675	15,679	15,730
12	122	Accum Prov for Non-Utility Property	(2,580)	(2,588)	(2,605)	(2,621)	(2,638)	(2,655)	(2,671)	(2,688)
13	123	Investment in Associated Companies	2,573	2,575	2,576	2,577	2,578	2,579	2,580	2,581
14	128	Other Special Funds	108,759	110,051	109,268	108,485	107,702	106,918	106,135	105,354
15		Total Other Property and Investments	124,496	125,680	124,882	124,085	123,315	122,517	121,723	120,977

Totals may not add due to rounding.

Supporting Schedules: B-19, B-20

Recap Schedules: B-1

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Derive the 13-month average system balance sheet by primary account by month for the test year, the prior year, and the most recent historical year. For accounts including non-electric utility amounts, show these amounts as a separate subaccount.

Type of Data Shown:
_ Projected Test Year Ended 12/31/14
X Prior Year Ended 12/31/13
_ Historical Year Ended 12/31/12
Witness: S. D. Ritenour

($000's)

(1) Line No.	(2) Account No.	(3) Account Name	(4) 8/2013	(5) 9/2013	(6) 10/2013	(7) 11/2013	(8) 12/2013	(9) 13-Month Average	(10) Reference RB WC CS ORP NEU
1		Utility Plant							
2	101	Electric Plant In Service	4,353,076	4,358,859	4,374,810	4,380,756	4,426,718	4,292,928	RB
3	105	Plant Held for Future Use	18,456	18,456	18,456	18,456	18,456	18,456	RB
4	106	Plant In Service Unclassified	0	0	0	0	0	27,880	RB
5	107	Construction Work in Progress	206,418	224,495	240,498	265,144	242,066	198,967	RB
6	108	Accum Prov for Depreciation	(1,415,228)	(1,425,903)	(1,436,602)	(1,447,163)	(1,456,207)	(1,400,696)	RB
7	111	Accum Prov for Amortization	(27,674)	(28,183)	(28,692)	(29,201)	(29,054)	(27,268)	RB
8	114	Electric Plant Acquistion Adjustments	2,116	2,095	2,073	2,052	2,031	2,159	RB
9		Total Utility Plant	3,137,164	3,149,819	3,170,543	3,190,044	3,204,010	3,112,426	
10		Other Property and Investments							
11	121	Non-Utility Property	15,743	15,757	15,811	15,822	15,829	15,722	NEU
12	122	Accum Prov for Non-Utility Property	(2,705)	(2,722)	(2,740)	(2,757)	(2,774)	(2,673)	NEU
13	123	Investment in Associated Companies	2,583	2,584	2,585	2,586	2,588	2,580	NEU
14	128	Other Special Funds	104,572	103,791	103,011	102,232	101,452	105,980	WC
15		Total Other Property and Investments	120,193	119,410	118,667	117,883	117,095	121,609	

REFERENCE:
RB = Rate Base; WC = Working Capital; CS = Capital Structure; ORP = Other Return Provided; NEU = Non-Electric Utility
Totals may not add due to rounding.

Supporting Schedules: B-19, B-20

Recap Schedules: B-1

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Derive the 13-month average system balance sheet by primary account by month for the test year, the prior year, and the most recent historical year. For accounts including non-electric utility amounts, show these amounts as a separate subaccount.

Type of Data Shown:
_ Projected Test Year Ended 12/31/14
X Prior Year Ended 12/31/13
_ Historical Year Ended 12/31/12
Witness: S. D. Ritenour

($000's)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
Line No.	Account No.	Account Name	12/2012	1/2013	2/2013	3/2013	4/2013	5/2013	6/2013	7/2013
1		Current and Accrued Assets								
2	131	Cash	13,040	6,011	6,011	6,011	6,011	6,011	6,011	6,011
3	134	Other Special Deposits	0	18	18	18	18	18	18	18
4	135	Working Funds	378	378	379	379	384	379	379	378
5	136	Temporary Cash Investments	0	0	0	0	0	0	0	0
6	142	Customer Accounts Receivable	56,076	70,654	71,280	58,386	59,126	59,896	77,073	88,970
7	143	Other Accounts Receivable	9,651	9,851	9,851	9,651	9,651	9,651	9,651	9,651
8	144	Accum Prov for Uncollectible Accounts	(1,490)	(2,087)	(2,101)	(1,609)	(1,429)	(1,364)	(1,380)	(1,571)
9	146	Accounts Receivable from Assoc Companies	13,624	13,488	10,311	4,447	7,323	8,280	14,531	20,459
10	151	Fuel Stock	145,398	137,530	134,953	137,453	141,758	143,224	140,930	132,008
11	154 and 163	Plant Materials and Operating Supplies	53,365	52,648	52,564	52,889	53,468	53,348	53,213	53,037
12	158	Allowance Inventory	8,094	8,021	7,947	7,874	7,800	7,726	7,653	7,579
13	165	Prepayments	26,045	28,804	26,617	28,926	5,495	6,854	7,159	7,463
14	171	Interest and Dividends Receivable	0	5	5	5	0	5	5	7
15	172	Rents Receivable	2,208	3,482	3,338	3,195	3,052	2,909	2,765	2,927
16	173	Accrued Utility Revenues	53,363	51,971	43,832	44,504	44,412	58,210	63,699	66,501
17	174	Miscellaneous Current and Accrued Assets	0	0	0	0	0	0	0	0
18	175	Derivative Instrument Assets	0	0	0	0	0	0	0	0
19	176	Derivative Instrument Assets - Hedges	4,357	4,357	4,357	4,357	4,357	4,357	4,357	4,357
20		Total Current and Accrued Assets	384,109	382,931	369,162	354,486	341,426	359,504	386,064	397,795

Totals may not add due to rounding.

Supporting Schedules: B-19, B-20

Recap Schedules: B-1

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Derive the 13-month average system balance sheet by primary account by month for the test year, the prior year, and the most recent historical year. For accounts including non-electric utility amounts, show these amounts as a separate subaccount.

Type of Data Shown:
_ Projected Test Year Ended 12/31/14
X Prior Year Ended 12/31/13
_ Historical Year Ended 12/31/12
Witness: S. D. Ritenour

($000's)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Line No.	Account No.	Account Name	8/2013	9/2013	10/2013	11/2013	12/2013	13-Month Average	Reference RB WC CS ORP NEU
1		Current and Accrued Assets							
2	131	Cash	6,011	6,011	6,011	6,011	6,011	6,553	WC
3	134	Other Special Deposits	18	18	18	18	18	17	WC
4	135	Working Funds	378	378	378	378	378	379	WC
5	136	Temporary Cash Investments	0	0	0	0	0	0	WC
6	142	Customer Accounts Receivable	84,726	95,218	76,946	63,351	68,099	71,523	WC
7	143	Other Accounts Receivable	9,651	9,651	9,651	9,651	9,651	9,651	WC
8	144	Accum Prov for Uncollectible Accounts	(1,529)	(1,896)	(1,640)	(1,375)	(1,799)	(1,636)	WC
9	146	Accounts Receivable from Assoc Companies	21,900	14,748	8,542	14,692	15,684	12,925	WC
10	151	Fuel Stock	122,542	120,535	121,963	124,333	123,479	132,777	WC
11	154 and 163	Plant Materials and Operating Supplies	52,894	52,763	53,055	53,672	53,609	53,117	WC
12	158	Allowance Inventory	7,506	7,432	7,358	7,285	7,211	7,653	WC
13	165	Prepayments	7,860	8,164	8,468	13,243	13,506	14,200	WC
14	171	Interest and Dividends Receivable	7	7	9	9	9	6	WC
15	172	Rents Receivable	2,783	2,639	2,496	2,352	2,208	2,796	WC
16	173	Accrued Utility Revenues	66,892	57,297	46,894	49,102	54,079	53,904	WC
17	174	Miscellaneous Current and Accrued Assets	0	0	0	0	0	0	WC
18	175	Derivative Instrument Assets	0	0	0	0	0	0	WC
19	176	Derivative Instrument Assets - Hedges	4,357	4,357	4,357	4,357	4,357	4,357	WC
20		Total Current and Accrued Assets	385,996	377,322	344,506	347,079	356,500	368,222	

REFERENCE:
RB = Rate Base; WC = Working Capital; CS = Capital Structure; ORP = Other Return Provided; NEU = Non-Electric Utility
Totals may not add due to rounding.

Supporting Schedules: B-19, B-20

Recap Schedules: B-1

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Derive the 13-month average system balance sheet by primary account by month for the test year, the prior year, and the most recent historical year. For accounts including non-electric utility amounts, show these amounts as a separate subaccount.

Type of Data Shown:
_ Projected Test Year Ended 12/31/14
X Prior Year Ended 12/31/13
_ Historical Year Ended 12/31/12
Witness: S. D. Ritenour

($000's)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
Line No.	Account No.	Account Name	12/2012	1/2013	2/2013	3/2013	4/2013	5/2013	6/2013	7/2013
1		Deferred Debits								
2	181	Unamortized Debt Expense	8,268	8,221	8,175	8,128	8,082	8,035	7,989	7,943
3	182	Regulatory Assets	460,868	462,735	466,011	468,942	472,218	475,494	478,426	481,701
4	183	Prelim Site Investigation Costs	16,807	16,372	16,430	16,487	16,545	16,603	16,661	16,662
5	184	Clearing Accounts	1,060	0	0	0	0	0	0	0
6	185	Temporary Facilities	0	0	0	0	0	0	0	0
7	186	Miscellaneous Deferred Debits	11,687	7,471	5,901	4,233	2,565	1,488	4,598	7,707
8	188	Research, Development, and Demo Expense	0	146	73	0	146	73	0	146
9	189	Unamortized Loss on Reacquired Debt	16,399	16,285	16,171	16,056	15,942	15,827	15,713	15,598
10	190	Accumulated Deferred Income Tax	76,219	76,047	75,875	75,703	75,531	75,359	75,187	75,015
11		Total Deferred Debits	591,308	587,277	588,636	589,549	591,029	592,879	598,574	604,772
12		Total Assets and Other Debits	4,114,631	4,125,992	4,127,033	4,132,002	4,156,565	4,186,807	4,224,633	4,249,454

Totals may not add due to rounding.

Supporting Schedules: B-19, B-20

Recap Schedules: B-1

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Derive the 13-month average system balance sheet by primary account by month for the test year, the prior year, and the most recent historical year. For accounts including non-electric utility amounts, show these amounts as a separate subaccount.

Type of Data Shown:
_ Projected Test Year Ended 12/31/14
X Prior Year Ended 12/31/13
_ Historical Year Ended 12/31/12
Witness: S. D. Ritenour

($000's)

(1) Line No.	(2) Account No.	(3) Account Name	(4) 8/2013	(5) 9/2013	(6) 10/2013	(7) 11/2013	(8) 12/2013	(9) 13-Month Average	(10) Reference RB WC CS ORP NEU
1		Deferred Debits							
2	181	Unamortized Debt Expense	7,899	7,855	7,810	7,766	7,721	7,992	CS
3	182	Regulatory Assets	484,977	487,909	491,185	494,461	497,673	478,662	WC
4	183	Prelim Site Investigation Costs	16,720	16,778	10,440	10,450	10,460	15,186	WC
5	184	Clearing Accounts	0	0	0	0	0	82	WC
6	185	Temporary Facilities	0	0	0	0	0	0	WC
7	186	Miscellaneous Deferred Debits	10,816	13,925	12,257	10,589	8,921	7,858	WC
8	188	Research, Development, and Demo Expense	73	0	146	73	0	67	WC
9	189	Unamortized Loss on Reacquired Debt	15,488	15,378	15,268	15,158	15,048	15,718	CS
10	190	Accumulated Deferred Income Tax	74,843	74,671	74,499	74,327	74,155	75,187	CS
11		Total Deferred Debits	610,816	616,516	611,605	612,824	613,978	600,752	
12		Total Assets and Other Debits	4,254,169	4,263,067	4,245,321	4,267,830	4,291,583	4,203,009	

REFERENCE:
RB = Rate Base; WC = Working Capital; CS = Capital Structure; ORP = Other Return Provided; NEU = Non-Electric Utility
Totals may not add due to rounding.

Supporting Schedules: B-19, B-20

Recap Schedules: B-1

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FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Derive the 13-month average system balance sheet by primary account by month for the test year, the prior year, and the most recent historical year. For accounts including non-electric utility amounts, show these amounts as a separate subaccount.

Type of Data Shown:
_ Projected Test Year Ended 12/31/14
X Prior Year Ended 12/31/13
_ Historical Year Ended 12/31/12
Witness: S. D. Ritenour

($000's)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
Line No.	Account No.	Account Name	12/2012	1/2013	2/2013	3/2013	4/2013	5/2013	6/2013	7/2013
1		Proprietary Capital								
2	201	Common Stock Issued	(393,060)	(393,060)	(393,060)	(393,060)	(393,060)	(393,060)	(393,060)	(393,060)
3	204	Preferred Stock Issued	(100,000)	(100,000)	(100,000)	(100,000)	(150,000)	(150,000)	(150,000)	(150,000)
4	211	Miscellaneous Paid-In Capital	(547,798)	(547,861)	(588,056)	(589,943)	(590,038)	(590,138)	(591,417)	(591,514)
5	214	Capital Stock Expense	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002
6	216	Unappropriated Retained Earnings	(241,465)	(222,813)	(229,433)	(234,174)	(210,438)	(220,824)	(235,593)	(224,442)
7	219	Accumulated Other Comprehensive Income	1,581	1,534	1,486	1,438	1,390	1,343	1,295	1,264
8		Total Proprietary Capital	(1,278,740)	(1,260,198)	(1,307,061)	(1,313,737)	(1,340,144)	(1,350,677)	(1,366,773)	(1,355,750)
9		Long Term Debt								
10	224	Other Long Term Debt	(1,253,955)	(1,253,955)	(1,253,955)	(1,253,955)	(1,253,955)	(1,253,955)	(1,308,955)	(1,248,955)
11	226	Unamortized Premium on Long Term Debt	8,085	8,034	7,984	7,934	7,884	7,833	7,783	7,734
12		Total Long Term Debt	(1,245,870)	(1,245,921)	(1,245,971)	(1,246,021)	(1,246,071)	(1,246,122)	(1,301,172)	(1,241,221)
13		Other Non-Current Liabilities								
14	228	Miscellaneous Operating Provisions	(257,618)	(258,047)	(258,457)	(258,868)	(259,278)	(259,687)	(260,098)	(260,510)
15	229	Prov for Rate Refunds	(1,807)	0	0	0	0	0	0	0
16	230	Asset Retirement Obligations	(16,055)	(16,055)	(16,055)	(16,055)	(16,055)	(16,055)	(16,055)	(16,055)
17		Total Other Non-Current Liabilities	(275,480)	(274,102)	(274,512)	(274,923)	(275,333)	(275,742)	(276,153)	(276,565)

Totals may not add due to rounding.

Supporting Schedules: B-19, B-20

Recap Schedules: B-1

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Derive the 13-month average system balance sheet by primary account by month for the test year, the prior year, and the most recent historical year. For accounts including non-electric utility amounts, show these amounts as a separate subaccount.

Type of Data Shown:
_ Projected Test Year Ended 12/31/14
X Prior Year Ended 12/31/13
_ Historical Year Ended 12/31/12
Witness: S. D. Ritenour

($000's)

(1) Line No.	(2) Account No.	(3) Account Name	(4) 8/2013	(5) 9/2013	(6) 10/2013	(7) 11/2013	(8) 12/2013	(9) 13-Month Average	(10) Reference RB WC CS ORP NEU
1		Proprietary Capital							
2	201	Common Stock Issued	(393,060)	(393,060)	(393,060)	(393,060)	(393,060)	(393,060)	CS
3	204	Preferred Stock Issued	(150,000)	(150,000)	(150,000)	(150,000)	(150,000)	(134,616)	CS
4	211	Miscellaneous Paid-In Capital	(591,609)	(592,884)	(592,977)	(593,022)	(597,891)	(585,011)	CS
5	214	Capital Stock Expense	2,002	2,002	2,002	2,002	2,002	2,002	CS
6	216	Unappropriated Retained Earnings	(241,591)	(255,098)	(231,573)	(236,483)	(244,364)	(232,947)	CS
7	219	Accumulated Other Comprehensive Income	1,233	1,202	1,171	1,140	1,109	1,322	CS
8		Total Proprietary Capital	(1,373,025)	(1,387,838)	(1,364,437)	(1,369,423)	(1,382,204)	(1,342,310)	
9		Long Term Debt							
10	224	Other Long Term Debt	(1,248,955)	(1,248,955)	(1,248,955)	(1,248,955)	(1,248,955)	(1,255,878)	CS
11	226	Unamortized Premium on Long Term Debt	7,687	7,640	7,592	7,545	7,498	7,787	CS
12		Total Long Term Debt	(1,241,268)	(1,241,315)	(1,241,363)	(1,241,410)	(1,241,457)	(1,248,091)	
13		Other Non-Current Liabilities							
14	228	Miscellaneous Operating Provisions	(260,921)	(261,349)	(261,762)	(262,176)	(262,590)	(260,104)	WC
15	229	Prov for Rate Refunds	0	0	0	0	0	(139)	WC
16	230	Asset Retirement Obligations	(16,055)	(16,055)	(16,055)	(16,055)	(16,055)	(16,055)	WC
17		Total Other Non-Current Liabilities	(276,976)	(277,404)	(277,817)	(278,231)	(278,645)	(276,298)	

REFERENCE:
RB = Rate Base; WC = Working Capital; CS = Capital Structure; ORP = Other Return Provided; NEU = Non-Electric Utility
Totals may not add due to rounding.

Supporting Schedules: B-19, B-20

Recap Schedules: B-1

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Derive the 13-month average system balance sheet by primary account by month for the test year, the prior year, and the most recent historical year. For accounts including non-electric utility amounts, show these amounts as a separate subaccount.

Type of Data Shown:
_ Projected Test Year Ended 12/31/14
X Prior Year Ended 12/31/13
_ Historical Year Ended 12/31/12
Witness: S. D. Ritenour

($000's)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
Line No.	Account No.	Account Name	12/2012	1/2013	2/2013	3/2013	4/2013	5/2013	6/2013	7/2013
1		Current and Accrued Liabilities								
2	231	Notes Payable	(3,232)	0	0	0	0	0	0	0
3	232	Accounts Payable	(54,317)	(72,178)	(66,249)	(69,130)	(74,796)	(66,187)	(64,941)	(66,078)
4	233	Notes Payable to Associated Companies	(123,769)	(132,447)	(84,911)	(94,192)	(57,187)	(61,035)	(42,868)	(77,073)
5	234	Accounts Payable to Associated Companies	(66,157)	(34,145)	(29,523)	(26,617)	(26,738)	(35,510)	(40,050)	(50,575)
6	235	Customer Deposits	(34,749)	(34,749)	(34,784)	(34,822)	(34,869)	(34,911)	(34,978)	(35,016)
7	236	Taxes Accrued	16,545	21,527	18,038	(9,487)	(6,692)	(8,495)	(18,232)	(27,660)
8	237	Interest Accrued	(12,363)	(14,309)	(18,057)	(14,277)	(11,821)	(16,267)	(10,147)	(12,085)
9	238	Dividends Declared	(1,551)	(29,350)	(29,867)	(1,533)	(29,573)	(30,313)	(2,203)	(29,566)
10	241	Tax Collections Payable	4,161	(1,183)	(268)	64	(1,097)	(4,517)	(1,021)	(1,969)
11	242	Miscellaneous Current and Accrued Liabilities	(27,072)	(30,294)	(31,424)	(21,328)	(22,498)	(22,997)	(24,018)	(25,032)
12	244	Derivative Instrument Liabilities	0	0	0	0	0	0	0	0
13	245	Derivative Instrument Liabilities - Hedges	(27,112)	(27,112)	(27,112)	(27,112)	(27,112)	(27,112)	(27,112)	(27,112)
14		Total Current and Accrued Liabilities	(329,616)	(354,240)	(304,157)	(298,434)	(292,383)	(307,344)	(265,570)	(352,166)
15		Deferred Credits								
16	253	Other Deferred Credits	(206,689)	(212,779)	(216,062)	(219,204)	(222,524)	(225,808)	(228,651)	(232,249)
17	254	Regulatory Liabilities	(49,630)	(46,510)	(43,390)	(40,172)	(36,953)	(34,326)	(35,885)	(37,444)
18	255	Accumulated Deferred Investment Tax Credits	(5,407)	(5,298)	(5,191)	(5,077)	(4,978)	(4,864)	(4,760)	(4,645)
19	281	Accumulated Deferred Income Taxes	(141,628)	(143,251)	(144,874)	(146,497)	(148,120)	(149,743)	(151,366)	(152,989)
20	282	Accumulated Deferred Income Taxes	(518,939)	(521,467)	(523,995)	(526,523)	(529,051)	(531,579)	(534,107)	(536,635)
21	283	Accumulated Deferred Income Taxes	(62,632)	(62,226)	(61,820)	(61,414)	(61,008)	(60,602)	(60,196)	(59,790)
22		Total Deferred Credits	(984,925)	(991,531)	(995,332)	(998,887)	(1,002,634)	(1,006,922)	(1,014,965)	(1,023,752)
23		Total Liabilities and Capital	(4,114,631)	(4,125,992)	(4,127,033)	(4,132,002)	(4,156,565)	(4,186,807)	(4,224,633)	(4,249,454)

Totals may not add due to rounding.

Supporting Schedules: B-19, B-20

Recap Schedules: B-1

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Derive the 13-month average system balance sheet by primary account by month for the test year, the prior year, and the most recent historical year. For accounts including non-electric utility amounts, show these amounts as a separate subaccount.

Type of Data Shown:
_ Projected Test Year Ended 12/31/14
X Prior Year Ended 12/31/13
_ Historical Year Ended 12/31/12
Witness: S. D. Ritenour

($000's)

(1) Line No.	(2) Account No.	(3) Account Name	(4) 8/2013	(5) 9/2013	(6) 10/2013	(7) 11/2013	(8) 12/2013	(9) 13-Month Average	(10) Reference RB WC CS ORP NEU
1		Current and Accrued Liabilities							
2	231	Notes Payable	0	0	0	0	0	(248)	CS
3	232	Accounts Payable	(67,055)	(67,093)	(76,308)	(75,009)	(67,011)	(68,181)	WC
4	233	Notes Payable to Associated Companies	(45,688)	(67,705)	(37,314)	(62,742)	(119,499)	(77,418)	CS
5	234	Accounts Payable to Associated Companies	(43,820)	(42,574)	(37,653)	(39,606)	(42,841)	(39,678)	WC
6	235	Customer Deposits	(35,050)	(35,049)	(35,050)	(35,054)	(35,075)	(34,935)	CS
7	236	Taxes Accrued	(36,826)	(37,967)	(42,068)	(11,070)	(4,937)	(11,333)	WC
8	237	Interest Accrued	(15,928)	(12,986)	(10,949)	(15,146)	(9,290)	(13,356)	WC
9	238	Dividends Declared	(30,306)	(2,196)	(29,566)	(30,306)	(2,196)	(19,117)	CS
10	241	Tax Collections Payable	(2,834)	2,224	4,919	(7,399)	(1,242)	(782)	WC
11	242	Miscellaneous Current and Accrued Liabilities	(26,046)	(25,769)	(26,691)	(27,706)	(29,274)	(26,167)	WC
12	244	Derivative Instrument Liabilities	0	0	0	0	0	0	WC
13	245	Derivative Instrument Liabilities - Hedges	(27,112)	(27,112)	(27,112)	(27,112)	(27,112)	(27,112)	WC
14		Total Current and Accrued Liabilities	(330,665)	(316,227)	(317,792)	(331,150)	(338,477)	(318,327)	
15		Deferred Credits							
16	253	Other Deferred Credits	(235,532)	(238,384)	(241,599)	(244,882)	(247,649)	(228,616)	WC
17	254	Regulatory Liabilities	(39,002)	(40,561)	(37,343)	(34,124)	(30,906)	(38,942)	WC
18	255	Accumulated Deferred Investment Tax Credits	(4,542)	(4,434)	(4,321)	(4,216)	(4,106)	(4,756)	CS
19	281	Accumulated Deferred Income Taxes	(154,612)	(156,235)	(157,858)	(159,481)	(161,104)	(151,366)	CS
20	282	Accumulated Deferred Income Taxes	(539,163)	(541,691)	(544,219)	(546,747)	(549,275)	(534,107)	CS
21	283	Accumulated Deferred Income Taxes	(59,384)	(58,978)	(58,572)	(58,166)	(57,760)	(60,196)	CS
22		Total Deferred Credits	(1,032,235)	(1,040,283)	(1,043,912)	(1,047,616)	(1,050,800)	(1,017,983)	
23		Total Liabilities and Capital	(4,254,169)	(4,263,067)	(4,245,321)	(4,267,830)	(4,291,583)	(4,203,009)	

REFERENCE:
RB = Rate Base; WC = Working Capital; CS = Capital Structure; ORP = Other Return Provided; NEU = Non-Electric Utility
Totals may not add due to rounding.

Supporting Schedules: B-19, B-20

Recap Schedules: B-1

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Derive the 13-month average system balance sheet by primary account by month for the test year, the prior year, and the most recent historical year. For accounts including non-electric utility amounts, show these amounts as a separate subaccount.

Type of Data Shown:
_ Projected Test Year Ended 12/31/14
_ Prior Year Ended 12/31/13
X Historical Year Ended 12/31/12
Witness: S. D. Ritenour

($000's)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
Line No.	Account No.	Account Name	12/2011	1/2012	2/2012	3/2012	4/2012	5/2012	6/2012	7/2012
1		Utility Plant								
2	101	Electric Plant In Service	3,021,290	3,036,492	3,051,343	3,106,540	3,120,141	3,626,377	3,646,353	3,659,145
3	105	Plant Held for Future Use	5,435	5,435	5,435	18,456	18,456	18,456	18,456	18,455
4	106	Plant In Service Unclassified	817,050	807,567	805,757	763,242	972,398	470,660	463,288	456,226
5	107	Construction Work in Progress	286,120	301,835	310,462	336,517	145,844	152,180	158,231	173,312
6	108	Accum Prov for Depreciation	(1,315,231)	(1,319,114)	(1,320,558)	(1,327,042)	(1,338,934)	(1,334,546)	(1,340,996)	(1,348,060)
7	111	Accum Prov for Amortization	(23,658)	(24,191)	(24,723)	(25,255)	(25,783)	(26,305)	(26,827)	(27,349)
8	114	Electric Plant Acquistion Adjustments	2,541	2,519	2,499	2,478	2,456	2,435	2,413	2,392
9		Total Utility Plant	2,793,547	2,810,543	2,830,215	2,876,936	2,894,578	2,909,257	2,920,918	2,934,121
10		Other Property and Investments								
11	121	Non-Utility Property	15,532	15,569	15,574	15,577	15,581	15,583	15,593	15,607
12	122	Accum Prov for Non-Utility Property	(2,233)	(2,268)	(2,304)	(2,339)	(2,374)	(2,409)	(2,388)	(2,421)
13	123	Investment in Associated Companies	3,095	3,221	3,224	3,230	3,266	3,237	3,172	2,541
14	128	Other Special Funds	97,817	97,626	98,371	98,093	97,793	97,492	97,192	96,892
15		Total Other Property and Investments	114,211	114,148	114,865	114,561	114,266	113,903	113,569	112,619

Totals may not add due to rounding.

Supporting Schedules: B-19, B-20

Recap Schedules: B-1

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Derive the 13-month average system balance sheet by primary account by month for the test year, the prior year, and the most recent historical year. For accounts including non-electric utility amounts, show these amounts as a separate subaccount.

Type of Data Shown:
_ Projected Test Year Ended 12/31/14
_ Prior Year Ended 12/31/13
X Historical Year Ended 12/31/12
Witness: S. D. Ritenour

($000's)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Line No.	Account No.	Account Name	8/2012	9/2012	10/2012	11/2012	12/2012	13-Month Average	Reference RB WC CS ORP NEU
1		Utility Plant							
2	101	Electric Plant In Service	3,713,638	3,737,356	3,747,054	3,813,050	3,875,337	3,473,394	RB
3	105	Plant Held for Future Use	18,456	18,456	18,456	18,456	18,456	15,451	RB
4	106	Plant In Service Unclassified	411,987	391,757	388,343	370,020	362,441	575,441	RB
5	107	Construction Work in Progress	183,367	200,696	218,086	186,637	136,155	214,726	RB
6	108	Accum Prov for Depreciation	(1,355,552)	(1,359,822)	(1,367,071)	(1,371,257)	(1,353,024)	(1,342,401)	RB
7	111	Accum Prov for Amortization	(27,871)	(28,393)	(28,912)	(29,426)	(26,933)	(26,586)	RB
8	114	Electric Plant Acquistion Adjustments	2,371	2,350	2,329	2,307	2,286	2,414	RB
9		Total Utility Plant	2,946,396	2,962,400	2,978,285	2,989,787	3,014,718	2,912,439	
10		Other Property and Investments							
11	121	Non-Utility Property	15,653	15,696	15,720	15,733	15,744	15,628	NEU
12	122	Accum Prov for Non-Utility Property	(2,455)	(2,489)	(2,524)	(2,549)	(2,580)	(2,410)	NEU
13	123	Investment in Associated Companies	2,555	2,558	2,500	2,572	2,573	2,903	NEU
14	128	Other Special Funds	96,591	96,291	95,990	95,707	108,759	98,047	WC
15		Total Other Property and Investments	112,344	112,056	111,686	111,463	124,496	114,168	

REFERENCE:
RB = Rate Base; WC = Working Capital; CS = Capital Structure; ORP = Other Return Provided; NEU = Non-Electric Utility
Totals may not add due to rounding.

Supporting Schedules: B-19, B-20

Recap Schedules: B-1

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Derive the 13-month average system balance sheet by primary account by month for the test year, the prior year, and the most recent historical year. For accounts including non-electric utility amounts, show these amounts as a separate subaccount.

Type of Data Shown:
_ Projected Test Year Ended 12/31/14
_ Prior Year Ended 12/31/13
X Historical Year Ended 12/31/12
Witness: S. D. Ritenour

($000's)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
Line No.	Account No.	Account Name	12/2011	1/2012	2/2012	3/2012	4/2012	5/2012	6/2012	7/2012
1		Current and Accrued Assets								
2	131	Cash	0	0	0	0	1,829	23,948	2,053	1,119
3	134	Other Special Deposits	11	11	11	11	11	11	11	18
4	135	Working Funds	379	379	379	379	379	379	379	379
5	136	Temporary Cash Investments	0	1,282	0	0	0	0	0	0
6	142	Customer Accounts Receivable	71,827	67,084	58,845	52,151	58,211	59,761	80,744	84,059
7	143	Other Accounts Receivable	13,107	12,367	9,586	8,212	11,325	11,540	7,543	8,645
8	144	Accum Prov for Uncollectible Accounts	(1,962)	(1,998)	(1,750)	(1,433)	(1,406)	(1,494)	(1,463)	(1,511)
9	146	Accounts Receivable from Assoc Companies	13,842	11,844	14,083	19,390	8,344	13,348	16,210	17,328
10	151	Fuel Stock	138,732	135,359	138,183	137,104	142,175	141,627	137,987	126,911
11	154 and 163	Plant Materials and Operating Supplies	49,802	49,803	51,703	51,257	51,317	53,058	53,872	54,158
12	158	Allowance Inventory	8,657	8,621	8,603	8,554	8,493	8,437	8,390	8,296
13	165	Prepayments	18,339	18,092	18,720	19,054	19,056	20,293	20,611	20,895
14	171	Interest and Dividends Receivable	224	224	224	(442)	0	0	0	0
15	172	Rents Receivable	104,625	111,916	110,987	3,328	3,438	3,824	3,270	3,447
16	173	Accrued Utility Revenues	49,921	46,332	42,312	48,705	47,681	64,054	57,575	61,571
17	174	Miscellaneous Current and Accrued Assets	0	0	0	0	0	0	0	0
18	175	Derivative Instrument Assets	0	0	0	0	0	0	0	0
19	176	Derivative Instrument Assets - Hedges	197	274	532	459	787	632	2,328	5,177
20		Total Current and Accrued Assets	467,701	461,590	452,418	346,729	351,640	399,418	389,510	390,492

Totals may not add due to rounding.

Supporting Schedules: B-19, B-20

Recap Schedules: B-1

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Derive the 13-month average system balance sheet by primary account by month for the test year, the prior year, and the most recent historical year. For accounts including non-electric utility amounts, show these amounts as a separate subaccount.

Type of Data Shown:
_ Projected Test Year Ended 12/31/14
_ Prior Year Ended 12/31/13
X Historical Year Ended 12/31/12
Witness: S. D. Ritenour

($000's)

(1) Line No.	(2) Account No.	(3) Account Name	(4) 8/2012	(5) 9/2012	(6) 10/2012	(7) 11/2012	(8) 12/2012	(9) 13-Month Average	(10) Reference RB WC CS ORP NEU
1		Current and Accrued Assets							
2	131	Cash	2,089	3,799	6,875	4,389	13,040	4,547	WC
3	134	Other Special Deposits	18	18	18	13,000	0	1,011	WC
4	135	Working Funds	429	379	379	378	378	383	WC
5	136	Temporary Cash Investments	0	0	0	0	0	99	WC
6	142	Customer Accounts Receivable	77,438	85,793	67,737	55,682	56,076	67,339	WC
7	143	Other Accounts Receivable	9,640	7,308	10,069	11,119	9,651	10,009	WC
8	144	Accum Prov for Uncollectible Accounts	(1,497)	(1,745)	(1,515)	(1,282)	(1,490)	(1,580)	WC
9	146	Accounts Receivable from Assoc Companies	15,677	12,413	10,111	17,474	13,624	14,130	WC
10	151	Fuel Stock	118,896	123,371	135,964	140,346	145,398	135,543	WC
11	154 and 163	Plant Materials and Operating Supplies	53,709	54,189	54,822	55,888	53,365	52,842	WC
12	158	Allowance Inventory	8,226	8,198	8,170	8,107	8,094	8,373	WC
13	165	Prepayments	21,283	21,457	21,686	25,878	26,045	20,878	WC
14	171	Interest and Dividends Receivable	0	0	0	0	0	18	WC
15	172	Rents Receivable	3,519	3,304	2,874	2,963	2,208	27,669	WC
16	173	Accrued Utility Revenues	59,929	52,812	49,021	49,069	53,363	52,488	WC
17	174	Miscellaneous Current and Accrued Assets	0	0	0	0	0	0	WC
18	175	Derivative Instrument Assets	0	0	0	0	0	0	WC
19	176	Derivative Instrument Assets - Hedges	1,544	10,883	12,673	5,979	4,357	3,525	WC
20		Total Current and Accrued Assets	370,900	382,179	378,884	388,990	384,109	397,274	

REFERENCE:
RB = Rate Base; WC = Working Capital; CS = Capital Structure; ORP = Other Return Provided; NEU = Non-Electric Utility
Totals may not add due to rounding.

Supporting Schedules: B-19, B-20

Recap Schedules: B-1

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Derive the 13-month average system balance sheet by primary account by month for the test year, the prior year, and the most recent historical year. For accounts including non-electric utility amounts, show these amounts as a separate subaccount.

Type of Data Shown:
_ Projected Test Year Ended 12/31/14
_ Prior Year Ended 12/31/13
X Historical Year Ended 12/31/12
Witness: S. D. Ritenour

($000's)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
Line No.	Account No.	Account Name	12/2011	1/2012	2/2012	3/2012	4/2012	5/2012	6/2012	7/2012
1		Deferred Debits								
2	181	Unamortized Debt Expense	9,272	9,225	9,177	9,184	9,400	9,383	8,326	8,289
3	182	Regulatory Assets	393,760	422,257	418,452	408,664	417,462	420,011	413,237	405,938
4	183	Prelim Site Investigation Costs	11,423	11,731	12,517	15,964	16,419	16,414	16,571	16,754
5	184	Clearing Accounts	95	90	32	118	54	77	395	109
6	185	Temporary Facilities	0	0	0	0	0	0	0	0
7	186	Miscellaneous Deferred Debits	14,487	10,738	17,166	7,334	6,339	729	5,120	10,452
8	188	Research, Development, and Demo Expense	0	145	73	0	146	73	0	146
9	189	Unamortized Loss on Reacquired Debt	14,437	14,319	14,211	14,104	13,996	13,889	17,087	16,972
10	190	Accumulated Deferred Income Tax	72,725	74,116	77,142	81,014	83,933	87,394	87,372	83,720
11		Total Deferred Debits	516,199	542,621	548,770	536,382	547,749	547,970	548,108	542,380
12		Total Assets and Other Debits	3,891,658	3,928,902	3,946,268	3,874,608	3,908,233	3,970,548	3,972,105	3,979,612

Totals may not add due to rounding.

Supporting Schedules: B-19, B-20

Recap Schedules: B-1

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Derive the 13-month average system balance sheet by primary account by month for the test year, the prior year, and the most recent historical year. For accounts including non-electric utility amounts, show these amounts as a separate subaccount.

Type of Data Shown:
_ Projected Test Year Ended 12/31/14
_ Prior Year Ended 12/31/13
X Historical Year Ended 12/31/12
Witness: S. D. Ritenour

($000's)

(1) Line No.	(2) Account No.	(3) Account Name	(4) 8/2012	(5) 9/2012	(6) 10/2012	(7) 11/2012	(8) 12/2012	(9) 13-Month Average	(10) Reference RB WC CS ORP NEU
1		Deferred Debits							
2	181	Unamortized Debt Expense	8,244	8,198	8,153	8,252	8,268	8,721	CS
3	182	Regulatory Assets	417,418	409,116	409,098	416,888	460,868	416,398	WC
4	183	Prelim Site Investigation Costs	16,795	16,848	16,894	16,685	16,807	15,525	WC
5	184	Clearing Accounts	221	113	149	33	1,060	196	WC
6	185	Temporary Facilities	0	0	0	0	0	0	WC
7	186	Miscellaneous Deferred Debits	15,371	18,006	14,742	13,870	11,687	11,234	WC
8	188	Research, Development, and Demo Expense	73	0	146	73	0	67	WC
9	189	Unamortized Loss on Reacquired Debt	16,857	16,743	16,628	16,514	16,399	15,550	CS
10	190	Accumulated Deferred Income Tax	80,762	80,579	79,213	76,270	76,219	80,035	CS
11		Total Deferred Debits	555,741	549,603	545,023	548,585	591,308	547,726	
12		Total Assets and Other Debits	3,985,381	4,006,238	4,013,878	4,038,825	4,114,631	3,971,607	

REFERENCE:
RB = Rate Base; WC = Working Capital; CS = Capital Structure; ORP = Other Return Provided; NEU = Non-Electric Utility
Totals may not add due to rounding.

Supporting Schedules: B-19, B-20

Recap Schedules: B-1

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Derive the 13-month average system balance sheet by primary account by month for the test year, the prior year, and the most recent historical year. For accounts including non-electric utility amounts, show these amounts as a separate subaccount.

Type of Data Shown:
_ Projected Test Year Ended 12/31/14
_ Prior Year Ended 12/31/13
X Historical Year Ended 12/31/12
Witness: S. D. Ritenour

($000's)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
Line No.	Account No.	Account Name	12/2011	1/2012	2/2012	3/2012	4/2012	5/2012	6/2012	7/2012
1		Proprietary Capital								
2	201	Common Stock Issued	(353,060)	(393,060)	(393,060)	(393,060)	(393,060)	(393,060)	(393,060)	(393,060)
3	204	Preferred Stock Issued	(100,000)	(100,000)	(100,000)	(100,000)	(100,000)	(100,000)	(100,000)	(100,000)
4	211	Miscellaneous Paid-In Capital	(542,709)	(542,936)	(543,114)	(544,511)	(544,787)	(545,019)	(545,734)	(546,064)
5	214	Capital Stock Expense	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002
6	216	Unappropriated Retained Earnings	(231,333)	(209,650)	(214,634)	(223,049)	(198,958)	(213,018)	(229,062)	(217,590)
7	219	Accumulated Other Comprehensive Income	2,154	2,106	2,059	2,011	1,963	1,915	1,868	1,820
8		Total Proprietary Capital	(1,222,946)	(1,241,538)	(1,246,747)	(1,256,607)	(1,232,840)	(1,247,180)	(1,263,986)	(1,252,892)
9		Long Term Debt								
10	224	Other Long Term Debt	(1,245,318)	(1,245,318)	(1,245,306)	(1,245,302)	(1,245,302)	(1,345,292)	(1,253,955)	(1,253,955)
11	226	Unamortized Premium on Long Term Debt	9,871	9,819	9,766	9,716	9,664	10,446	8,388	8,337
12		Total Long Term Debt	(1,235,447)	(1,235,499)	(1,235,540)	(1,235,586)	(1,235,638)	(1,334,846)	(1,245,567)	(1,245,618)
13		Other Non-Current Liabilities								
14	228	Miscellaneous Operating Provisions	(205,753)	(218,626)	(218,843)	(218,053)	(217,986)	(217,927)	(217,753)	(217,767)
15	229	Prov for Rate Refunds	(565)	(627)	(720)	(766)	(933)	(1,012)	(1,312)	(1,374)
16	230	Asset Retirement Obligations	(10,729)	(10,769)	(10,811)	(10,852)	(10,894)	(10,830)	(10,872)	(10,914)
17		Total Other Non-Current Liabilities	(217,047)	(230,022)	(230,374)	(229,671)	(229,813)	(229,769)	(229,937)	(230,055)

Totals may not add due to rounding.

Supporting Schedules: B-19, B-20

Recap Schedules: B-1

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Derive the 13-month average system balance sheet by primary account by month for the test year, the prior year, and the most recent historical year. For accounts including non-electric utility amounts, show these amounts as a separate subaccount.

Type of Data Shown:
_ Projected Test Year Ended 12/31/14
_ Prior Year Ended 12/31/13
X Historical Year Ended 12/31/12
Witness: S. D. Ritenour

($000's)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Line No.	Account No.	Account Name	8/2012	9/2012	10/2012	11/2012	12/2012	13-Month Average	Reference RB WC CS ORP NEU
1		Proprietary Capital							
2	201	Common Stock Issued	(393,060)	(393,060)	(393,060)	(393,060)	(393,060)	(389,983)	CS
3	204	Preferred Stock Issued	(100,000)	(100,000)	(100,000)	(100,000)	(100,000)	(100,000)	CS
4	211	Miscellaneous Paid-In Capital	(546,216)	(546,875)	(547,017)	(547,124)	(547,798)	(545,377)	CS
5	214	Capital Stock Expense	2,002	2,002	2,002	2,002	2,002	2,002	CS
6	216	Unappropriated Retained Earnings	(232,722)	(247,866)	(226,911)	(236,185)	(241,465)	(224,804)	CS
7	219	Accumulated Other Comprehensive Income	1,772	1,726	1,677	1,629	1,581	1,868	CS
8		Total Proprietary Capital	(1,268,224)	(1,284,073)	(1,263,309)	(1,272,738)	(1,278,740)	(1,256,293)	
9		Long Term Debt							
10	224	Other Long Term Debt	(1,253,955)	(1,253,955)	(1,253,955)	(1,266,955)	(1,253,955)	(1,258,656)	CS
11	226	Unamortized Premium on Long Term Debt	8,287	8,236	8,186	8,135	8,085	8,995	CS
12		Total Long Term Debt	(1,245,668)	(1,245,719)	(1,245,769)	(1,258,820)	(1,245,870)	(1,249,661)	
13		Other Non-Current Liabilities							
14	228	Miscellaneous Operating Provisions	(218,665)	(218,575)	(217,094)	(216,972)	(257,618)	(220,126)	WC
15	229	Prov for Rate Refunds	(1,437)	(1,535)	(1,597)	(1,659)	(1,807)	(1,180)	WC
16	230	Asset Retirement Obligations	(10,957)	(10,999)	(11,042)	(11,085)	(16,055)	(11,293)	WC
17		Total Other Non-Current Liabilities	(231,059)	(231,109)	(229,733)	(229,716)	(275,480)	(232,599)	

REFERENCE:
RB = Rate Base; WC = Working Capital; CS = Capital Structure; ORP = Other Return Provided; NEU = Non-Electric Utility
Totals may not add due to rounding.

Supporting Schedules: B-19, B-20

Recap Schedules: B-1

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FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Derive the 13-month average system balance sheet by primary account by month for the test year, the prior year, and the most recent historical year. For accounts including non-electric utility amounts, show these amounts as a separate subaccount.

Type of Data Shown:
_ Projected Test Year Ended 12/31/14
_ Prior Year Ended 12/31/13
X Historical Year Ended 12/31/12
Witness: S. D. Ritenour

($000's)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
Line No.	Account No.	Account Name	12/2011	1/2012	2/2012	3/2012	4/2012	5/2012	6/2012	7/2012
1		Current and Accrued Liabilities								
2	231	Notes Payable	(3,580)	(3,580)	(2,375)	0	0	(3,232)	(3,232)	(3,232)
3	232	Accounts Payable	(66,158)	(53,206)	(61,108)	(54,673)	(64,021)	(54,372)	(49,481)	(45,978)
4	233	Notes Payable to Associated Companies	(110,927)	(71,892)	(65,091)	(83,589)	(93,082)	(11,998)	(113,675)	(90,179)
5	234	Accounts Payable to Associated Companies	(54,870)	(45,414)	(46,929)	(45,705)	(45,529)	(57,226)	(60,204)	(74,196)
6	235	Customer Deposits	(35,779)	(35,689)	(35,813)	(36,010)	(36,118)	(36,094)	(36,028)	(36,041)
7	236	Taxes Accrued	12,742	23,411	28,423	(1,933)	1,873	993	8,998	13,150
8	237	Interest Accrued	(14,106)	(15,103)	(19,153)	(18,922)	(12,634)	(17,601)	(11,911)	(14,000)
9	238	Dividends Declared	(1,550)	(30,501)	(30,501)	(1,551)	(30,501)	(30,501)	(1,551)	(30,501)
10	241	Tax Collections Payable	4,540	(1,287)	(422)	13	307	528	504	936
11	242	Miscellaneous Current and Accrued Liabilities	(30,189)	(36,299)	(31,388)	(20,890)	(21,310)	(20,757)	(24,867)	(21,418)
12	244	Derivative Instrument Liabilities	0	0	0	0	0	0	0	0
13	245	Derivative Instrument Liabilities - Hedges	(40,983)	(52,685)	(47,682)	(53,824)	(51,328)	(48,520)	(38,911)	(29,587)
14		Total Current and Accrued Liabilities	(340,860)	(322,245)	(312,039)	(317,084)	(352,343)	(278,780)	(330,358)	(331,046)
15		Deferred Credits								
16	253	Other Deferred Credits	(267,134)	(277,267)	(280,992)	(176,126)	(179,714)	(183,307)	(186,572)	(190,304)
17	254	Regulatory Liabilities	(58,480)	(58,049)	(62,171)	(67,170)	(71,312)	(75,875)	(79,596)	(79,401)
18	255	Accumulated Deferred Investment Tax Credits	(6,760)	(6,651)	(6,535)	(6,422)	(6,309)	(6,197)	(6,084)	(5,971)
19	281	Accumulated Deferred Income Taxes	(78,392)	(84,020)	(89,647)	(95,275)	(100,903)	(106,531)	(112,159)	(117,787)
20	282	Accumulated Deferred Income Taxes	(406,744)	(415,659)	(424,323)	(432,737)	(441,401)	(450,064)	(458,486)	(467,149)
21	283	Accumulated Deferred Income Taxes	(57,848)	(57,952)	(57,900)	(57,930)	(57,960)	(57,999)	(59,360)	(59,389)
22		Total Deferred Credits	(875,358)	(899,598)	(921,568)	(835,660)	(857,599)	(879,973)	(902,257)	(920,001)
23		Total Liabilities and Capital	(3,891,658)	(3,928,902)	(3,946,268)	(3,874,608)	(3,908,233)	(3,970,548)	(3,972,105)	(3,979,612)

Totals may not add due to rounding.

Supporting Schedules: B-19, B-20

Recap Schedules: B-1

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Derive the 13-month average system balance sheet by primary account by month for the test year, the prior year, and the most recent historical year. For accounts including non-electric utility amounts, show these amounts as a separate subaccount.

Type of Data Shown:
_ Projected Test Year Ended 12/31/14
_ Prior Year Ended 12/31/13
X Historical Year Ended 12/31/12
Witness: S. D. Ritenour

($000's)

(1) Line No.	(2) Account No.	(3) Account Name	(4) 8/2012	(5) 9/2012	(6) 10/2012	(7) 11/2012	(8) 12/2012	(9) 13-Month Average	(10) Reference RB WC CS ORP NEU
1		Current and Accrued Liabilities							
2	231	Notes Payable	(3,232)	(3,232)	(3,232)	(3,232)	(3,232)	(2,722)	CS
3	232	Accounts Payable	(42,768)	(49,545)	(47,816)	(52,188)	(54,317)	(53,510)	WC
4	233	Notes Payable to Associated Companies	(65,389)	(15,996)	(22,498)	(42,495)	(123,769)	(70,045)	CS
5	234	Accounts Payable to Associated Companies	(72,016)	(74,169)	(70,984)	(72,129)	(68,157)	(60,425)	WC
6	235	Customer Deposits	(35,973)	(35,849)	(35,801)	(35,735)	(34,749)	(35,822)	CS
7	236	Taxes Accrued	18,429	(33,591)	(24,451)	5,706	16,545	5,407	WC
8	237	Interest Accrued	(17,532)	(17,622)	(12,324)	(15,323)	(12,363)	(15,277)	WC
9	238	Dividends Declared	(30,501)	(1,551)	(30,501)	(30,501)	(1,551)	(19,366)	CS
10	241	Tax Collections Payable	1,418	1,968	2,859	3,814	4,161	1,488	WC
11	242	Miscellaneous Current and Accrued Liabilities	(28,275)	(21,732)	(23,582)	(23,284)	(27,072)	(25,466)	WC
12	244	Derivative Instrument Liabilities	0	0	0	0	0	0	WC
13	245	Derivative Instrument Liabilities - Hedges	(37,212)	(23,691)	(21,352)	(26,343)	(27,112)	(38,402)	WC
14		Total Current and Accrued Liabilities	(313,051)	(275,010)	(289,682)	(291,710)	(329,616)	(314,140)	
15		Deferred Credits							
16	253	Other Deferred Credits	(193,506)	(197,075)	(200,838)	(204,238)	(206,689)	(211,059)	WC
17	254	Regulatory Liabilities	(69,609)	(79,875)	(75,906)	(58,751)	(49,630)	(68,140)	WC
18	255	Accumulated Deferred Investment Tax Credits	(5,858)	(5,746)	(5,633)	(5,520)	(5,407)	(6,084)	CS
19	281	Accumulated Deferred Income Taxes	(123,415)	(129,043)	(134,671)	(140,298)	(141,628)	(111,828)	CS
20	282	Accumulated Deferred Income Taxes	(475,560)	(499,208)	(508,923)	(517,586)	(518,939)	(462,829)	CS
21	283	Accumulated Deferred Income Taxes	(59,431)	(59,380)	(59,414)	(59,448)	(62,632)	(58,975)	CS
22		Total Deferred Credits	(927,379)	(970,327)	(985,385)	(985,841)	(984,925)	(918,914)	
23		Total Liabilities and Capital	(3,985,381)	(4,006,238)	(4,013,878)	(4,038,825)	(4,114,631)	(3,971,607)	

REFERENCE:
RB = Rate Base; WC = Working Capital; CS = Capital Structure; ORP = Other Return Provided; NEU = Non-Electric Utility
Totals may not add due to rounding.

Supporting Schedules: B-19, B-20

Recap Schedules: B-1

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide 13-month average system balance sheets by primary account for the most recent two historical calendar years, not including the historical test year if provided elsewhere.

($000's)

Type of Data Shown:
____ Projected Test Year Ended 12/31/14
____ Prior Year Ended 12/31/13
__X__ Historical Years Ended 12/31/11 - 12/31/12
Witness: C. J. Erickson

(1) Line No.	(2) Account No.	(3) Account Name	(4) 2011	(5) 2012
1		Utility Plant		
2	101	Electric Plant In Service	2,966,837	3,473,394
3	105	Plant Held for Future Use	5,574	15,451
4	106	Plant In Service Unclassified	782,944	575,441
5	107	Construction Work In Progress	230,657	214,726
6	108	Accum Prov for Depreciation	(1,282,282)	(1,342,401)
7	111	Accum Prov for Amortization	(23,609)	(26,586)
8	114	Electric Plant Acquisition Adjustments	2,669	2,414
9		Total Utility Plant	2,682,790	2,912,439
10		Other Property and Investments		
11	121	Non-Utility Property	15,401	15,628
12	122	Accum Prov for Non-Utility Property	(2,033)	(2,410)
13	123	Investment in Associated Companies	2,970	2,903
14	128	Other Special Funds	97,441	98,047
15		Total Other Property and Investments	113,779	114,168

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide 13-month average system balance sheets by primary account for the most recent two historical calendar years, not including the historical test year if provided elsewhere.

($000's)

Type of Data Shown:
____ Projected Test Year Ended 12/31/14
____ Prior Year Ended 12/31/13
__X__ Historical Years Ended 12/31/11 - 12/31/12
Witness: C. J. Erickson

(1) Line No.	(2) Account No.	(3) Account Name	(4) 2011	(5) 2012
1		Current and Accrued Assets		
2	131	Cash	4,762	4,547
3	134	Other Special Deposits	11	1,011
4	135	Working Funds	380	383
5	136	Temporary Cash Investments	335	99
6	142	Customer Accounts Receivable	77,211	67,339
7	143	Other Accounts Receivable	12,459	10,009
8	144	Accum Prov for Uncollectible Accounts	(1,827)	(1,580)
9	146	Accounts Receivable from Assoc Companies	10,772	14,130
10	151	Fuel Stock	140,167	135,543
11	154 and 163	Plant Materials and Operating Supplies	48,355	52,842
12	158	Allowance Inventory	11,572	8,373
13	165	Prepayments	20,981	20,878
14	171	Interest and Dividends Receivable	315	18
15	172	Rents Receivable	101,412	27,669
16	173	Accrued Utility Revenues	57,300	52,488
17	174	Miscellaneous Current and Accrued Assets	0	0
18	175	Derivative Instrument Assets	3	0
19	176	Derivative Instrument Assets - Hedges	1,517	3,525
20		Total Current and Accrued Assets	485,725	397,274

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide 13-month average system balance sheets by primary account for the most recent two historical calendar years, not including the historical test year if provided elsewhere.

($000's)

Type of Data Shown:
____ Projected Test Year Ended 12/31/14
____ Prior Year Ended 12/31/13
X Historical Years Ended 12/31/11 - 12/31/12
Witness: C. J. Erickson

(1) Line No.	(2) Account No.	(3) Account Name	(4) 2011	(5) 2012
21		Deferred Debits		
22	181	Unamortized Debt Expense	9,479	8,721
23	182	Regulatory Assets	330,930	416,398
24	183	Prelim Site Investigation Costs	11,333	15,525
25	184	Clearing Accounts	184	196
26	185	Temporary Facilities	0	0
27	186	Miscellaneous Deferred Debits	10,179	11,234
28	188	Research, Development, and Demo Expense	50	67
29	189	Unamortized Loss on Reacquired Debt	15,150	15,550
30	190	Accumulated Deferred Income Tax	73,545	80,035
31		Total Deferred Debits	450,850	547,726
32		Total Assets and Other Debits	3,733,144	3,971,607

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide 13-month average system balance sheets by primary account for the most recent two historical calendar years, not including the historical test year if provided elsewhere.

($000's)

Type of Data Shown:
____ Projected Test Year Ended 12/31/14
____ Prior Year Ended 12/31/13
X Historical Years Ended 12/31/11 - 12/31/12
Witness: C. J. Erickson

(1)	(2)	(3)	(4)	(5)
Line No.	Account No.	Account Name	2011	2012
1		Proprietary Capital		
2	201	Common Stock Issued	(349,214)	(389,983)
3	204	Preferred Stock Issued	(100,000)	(100,000)
4	211	Miscellaneous Paid-In Capital	(540,509)	(545,377)
5	214	Capital Stock Expense	2,002	2,002
6	216	Unappropriated Retained Earnings	(221,954)	(224,804)
7	219	Accumulated Other Comprehensive Income	2,440	1,868
8		Total Proprietary Capital	(1,207,235)	(1,256,293)
9		Long Term Debt		
10	224	Other Long Term Debt	(1,248,281)	(1,258,656)
11	226	Unamortized Premium on Long Term Debt	8,664	8,995
12		Total Long Term Debt	(1,239,617)	(1,249,661)
13		Other Non-Current Liabilities		
14	228	Miscellaneous Operating Provisions	(176,613)	(220,126)
15	229	Prov for Rate Refunds	(281)	(1,180)
16	230	Asset Retirement Obligations	(11,193)	(11,293)
17		Total Other Non-Current Liabilities	(188,087)	(232,599)

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide 13-month average system balance sheets by primary account for the most recent two historical calendar years, not including the historical test year if provided elsewhere.

($000's)

Type of Data Shown:
____ Projected Test Year Ended 12/31/14
____ Prior Year Ended 12/31/13
__X__ Historical Years Ended 12/31/11 - 12/31/12
Witness: C. J. Erickson

(1) Line No.	(2) Account No.	(3) Account Name	(4) 2011	(5) 2012
1		Current and Accrued Liabilities		
2	231	Notes Payable	(6,879)	(2,722)
3	232	Accounts Payable	(61,386)	(53,510)
4	233	Notes Payable to Associated Companies	(57,925)	(70,045)
5	234	Accounts Payable to Associated Companies	(52,927)	(60,425)
6	235	Customer Deposits	(35,889)	(35,822)
7	236	Taxes Accrued	(6,463)	5,407
8	237	Interest Accrued	(15,229)	(15,277)
9	238	Dividends Declared	(18,474)	(19,366)
10	241	Tax Collections Payable	1,434	1,488
11	242	Miscellaneous Current and Accrued Liabilities	(24,501)	(25,466)
12	244	Derivative Instrument Liabilities	(1)	0
13	245	Derivative Instrument Liabilities - Hedges	(15,862)	(38,402)
14		Total Current and Accrued Liabilities	(294,102)	(314,140)
15		Deferred Credits		
16	253	Other Deferred Credits	(244,475)	(211,059)
17	254	Regulatory Liabilities	(51,620)	(68,140)
18	255	Accumulated Deferred Investment Tax Credits	(7,433)	(6,084)
19	281	Accumulated Deferred Income Taxes	(68,040)	(111,828)
20	282	Accumulated Deferred Income Taxes	(374,871)	(462,829)
21	283	Accumulated Deferred Income Taxes	(57,664)	(58,975)
22		Total Deferred Credits	(804,103)	(918,914)
23		Total Liabilities and Capital	(3,733,144)	(3,971,607)

Supporting Schedules:

Recap Schedules:

SCHEDULE B-5 | Detail of Changes in Rate Base | Page 1 of 2

FLORIDA PUBLIC SERVICE COMMISSION

Company: GULF POWER COMPANY

Docket No.: 130140-EI

EXPLANATION: Provide the data listed below regarding all changes in rate base primary accounts that exceed 1/20th of one percent (.0005) of total rate base and ten percent from the prior year to the test year. Quantify each reason for the change.

Type of data shown:
X Projected Test Year Ended 12/31/14
X Prior Year Ended 12/31/13
_ Historical Year Ended 12/31/12
Witness: S. D. Ritenour

(1) Line No.	(2) Account Number	(3) Account Name	(4) Test Year Ended 12/31/14 ($000's)	(5) Prior Year Ended 12/31/13 ($000's)	(6) Difference (4) - (5) ($000's)	(7) Percent Change (6) / (5)	(8) Reason(s) For Change
1	106	Plant in Service Unclassified	0	27,880	(27,880)	-100.00%	Gulf does not forecast unclassified property. This decrease is a function of the December 2012 actual balance, included in the 13-month average of the prior year.
4	107	Construction Work in Progress	409,402	198,967	210,435	105.76%	The increase is driven primarily by the large ongoing capital expenditures for the Daniel 1 & 2 Scrubbers and for Transmission projects necessary to comply with the Mercury and Air Toxics Standards (MATS) rule.
8	151	Fuel Stock	103,229	132,777	(29,548)	-22.25%	The decrease in total fuel inventory value from 2013 to 2014 is due to a reduction in the quantity of coal held in inventory.
10	165	Prepayments	16,734	14,200	2,534	17.85%	The majority of the change is due to an increase in the prepaid Long Term Service Agreement on Smith Unit 3.
12	183	Prelim Site Investigation Costs	8,894	15,186	(6,292)	-41.43%	The majority of the change is due to the reclassification of several ECRC projects from Preliminary Site Investigation into CWIP.
15	186	Miscellaneous Deferred Debits	3,082	7,858	(4,776)	-60.78%	The primary reason for the decrease are the PPA deferred debits, which are offset in regulatory liabilities. Gulf projects the balances to be zero by May 2014, thus causing a reduction between the 13-month average of the prior year and test year.
19	236	Taxes Accrued	(19,012)	(11,333)	(7,679)	67.76%	Accrued taxes are a function of pre-tax income and book-to-tax differences which can drive taxable income up or down, and result in either a tax receivable or payable balance. As shown on B-3, a tax receivable balance is shown for the months of December 2012 through February 2013; thereafter the balance is a tax payable. This is the primary reason for the increase in the 13-month average taxes accrued account.

Supporting Schedules:

Recap Schedules: B-1

FLORIDA PUBLIC SERVICE COMMISSION

Company: GULF POWER COMPANY

Docket No.: 130140-EI

EXPLANATION: Provide the data listed below regarding all changes in rate base primary accounts that exceed 1/20th of one percent (.0005) of total rate base and ten percent from the prior year to the test year. Quantify each reason for the change.

Type of data shown:
X Projected Test Year Ended 12/31/14
X Prior Year Ended 12/31/13
_ Historical Year Ended 12/31/12
Witness: S. D. Ritenour

(1) Line No.	(2) Account Number	(3) Account Name	(4) Test Year Ended 12/31/14 ($000's)	(5) Prior Year Ended 12/31/13 ($000's)	(6) Difference (4) - (5) ($000's)	(7) Percent Change (6) / (5)	(8) Reason(s) For Change
1	253	Other Deferred Credits	(257,316)	(228,616)	(28,700)	12.55%	The majority of the change is due to an increase in the Central Alabama PPA balance, which is offset in regulatory assets.
2							
3	254	Regulatory Liabilities	(24,373)	(38,942)	14,569	-37.41%	The primary reason for the decrease is the clause over-recoveries and PPA deferred credits. The PPA deferred credits are offset in miscellaneous deferred debits. Gulf projects the December 2012 clause over-recovery actual balances to be zero by December 2013 and the PPA deferred credits to be zero by May 2014, thus causing a reduction between the 13-month average of the prior year and test year.
4							
5							
6							
7							
8							
9							

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide a development of jurisdictional separation factors for rate base for the test year, and the prior year if the test year is projected.

Type of Data Shown:
X Projected Test Year Ended 12/31/14
__ Prior Year Ended 12/31/13
__ Historical Year Ended 12/31/12
Witness: M. T. O'Sheasy

($000's)

(1) Line No.	(2) Description	(3) Total Adjusted Utility	(4) Unit Power Sales	(5) Total Adjusted Utility Net of UPS	(6) Jurisdictional Amount	(7) Jurisdictional Separation Factor
1	ELECTRIC PLANT IN SERVICE					
2	PRODUCTION	1,571,047	380,174	1,190,873	1,155,365	0.9701832
3	TRANSMISSION					
4	Land and Land Rights	20,315	0	20,315	19,727	0.9710559
5	Structures and Improvements	10,991	0	10,991	10,706	0.9740697
6	Station Equipment	164,006	6,347	157,659	154,100	0.9774260
7	Towers and Fixtures	42,804	0	42,804	41,528	0.9701833
8	Poles and Fixtures	148,976	0	148,976	144,534	0.9701833
9	Overhead Conductors and Devices	85,526	0	85,526	82,976	0.9701833
10	Underground Conductors and Devices	14,095	0	14,095	13,675	0.9701833
11	Roads and Trails	236	0	236	229	0.9701833
12	Total Transmission	486,949	6,347	480,602	467,475	0.9726863
13	DISTRIBUTION					
14	Land and Land Rights	4,670	0	4,670	4,607	0.9865096
15	Structures and Improvements	23,227	0	23,227	22,801	0.9816593
16	Station Equipment	226,026	0	226,026	222,354	0.9837541
17	Poles and Fixtures	133,789	0	133,789	133,789	1.0000000
18	Overhead Conductors and Devices	137,611	0	137,611	137,611	1.0000000
19	Underground Conduits	1,161	0	1,161	1,161	1.0000000
20	Underground Conductors and Devices	146,818	0	146,818	146,818	1.0000000
21	Line Transformers	253,750	0	253,750	253,750	1.0000000
22	Services	99,675	0	99,675	99,675	1.0000000
23	Meters	65,096	0	65,096	64,981	0.9982334
24	Street Lighting	65,351	0	65,351	65,351	1.0000000
25	Total Distribution	1,157,174	0	1,157,174	1,152,898	0.9963048
26	GENERAL PLANT	175,906	4,658	171,248	168,430	0.9835443
27	TOTAL ELECTRIC GROSS PLANT	3,391,076	391,179	2,999,897	2,944,168	0.9814230

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide a development of jurisdictional separation factors for rate base for the test year, and the prior year if the test year is projected.

Type of Data Shown:
X Projected Test Year Ended 12/31/14
__ Prior Year Ended 12/31/13
__ Historical Year Ended 12/31/12
Witness: M. T. O'Sheasy

($000's)

(1) Line No.	(2) Description	(3) Total Adjusted Utility	(4) Unit Power Sales	(5) Total Adjusted Utility Net of UPS	(6) Jurisdictional Amount	(7) Jurisdictional Separation Factor
1	ACCUMULATED DEPRECIATION					
2	PRODUCTION	759,866	125,715	634,151	615,243	0.9701838
3	TRANSMISSION					
4	Land and Land Rights	6,816	0	6,816	6,613	0.9702171
5	Structures and Improvements	3,645	0	3,645	3,550	0.9739369
6	Station Equipment	32,146	2,418	29,728	29,057	0.9774287
7	Towers and Fixtures	25,433	0	25,433	24,675	0.9701833
8	Poles and Fixtures	26,313	0	26,313	25,528	0.9701833
9	Overhead Conductors and Devices	26,168	0	26,168	25,388	0.9701833
10	Underground Conductors and Devices	7,657	0	7,657	7,429	0.9701833
11	Roads and Trails	40	0	40	39	0.9701833
12	Total Transmission	128,218	2,418	125,800	122,279	0.9720111
13	DISTRIBUTION					
14	Land and Land Rights	35	0	35	35	1.0000000
15	Structures and Improvements	7,861	0	7,861	7,717	0.9816817
16	Station Equipment	61,193	0	61,193	60,199	0.9837563
17	Poles and Fixtures	68,832	0	68,832	68,832	1.0000000
18	Overhead Conductors and Devices	48,656	0	48,656	48,656	1.0000000
19	Underground Conduits	800	0	800	800	1.0000000
20	Underground Conductors and Devices	52,723	0	52,723	52,723	1.0000000
21	Line Transformers	92,899	0	92,899	92,899	1.0000000
22	Services	50,834	0	50,834	50,834	1.0000000
23	Meters	21,743	0	21,743	21,717	0.9988042
24	Street Lighting	33,445	0	33,445	33,445	1.0000000
25	Total Distribution	439,021	0	439,021	437,857	0.9973486
26	GENERAL PLANT	70,939	1,862	69,077	67,940	0.9835401
27	TOTAL ELEC. ACCUM. DEPRECIATION	1,398,044	129,995	1,268,049	1,243,319	0.9804976

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide a development of jurisdictional separation factors for rate base for the test year, and the prior year if the test year is projected.

Type of Data Shown:
X Projected Test Year Ended 12/31/14
__ Prior Year Ended 12/31/13
__ Historical Year Ended 12/31/12
Witness: M. T. O'Sheasy

($000's)

(1) Line No.	(2) Description	(3) Total Adjusted Utility	(4) Unit Power Sales	(5) Total Adjusted Utility Net of UPS	(6) Jurisdictional Amount	(7) Jurisdictional Separation Factor
1	NET PLANT IN SERVICE	1,993,032	261,184	1,731,848	1,700,849	0.9821006
2	CWIP - NON-INTEREST BEARING					
3	Production	17,325	6,557	10,768	10,447	0.9701895
4	Transmission	10,704	0	10,704	10,412	0.9727205
5	Distribution	5,818	0	5,818	5,797	0.9963905
6	TOTAL CWIP - NON-INTEREST BEARING	33,847	6,557	27,290	26,656	0.9767680
7	PLANT HELD FOR FUTURE USE	5,435	0	5,435	5,276	0.9707452
8	UNAMOR. PLANT ACQUISITION ADJ.	1,903	1,903	0	0	0.0000000
9	WORKING CAPITAL					
10	Net Current Assets and Liabilities	(7,220)	(174)	(7,046)	(6,918)	0.9818337
11	Fuel Stock	103,229	7,203	96,026	93,225	0.9708308
12	Other Materials & Supplies	51,129	2,330	48,799	47,786	0.9792414
13	Prepayments	16,734	245	16,489	16,183	0.9814422
14	Other Investments	73,473	0	73,473	72,264	0.9835450
15	Preliminary Survey and Investigation Charges	5,238	0	5,238	5,082	0.9702176
16	Unamortized Rate Case Expense	0	0	0	0	0.0000000
17	Environmental Cleanup	58,878	1,417	57,461	56,414	0.9817789
18	Injuries & Damages Reserve	(3,354)	(98)	(3,256)	(3,202)	0.9834152
19	Property Insurance Reserve	(16,782)	(1,373)	(15,409)	(15,133)	0.9820884
20	Post-Retirement Benefits Reserve	(70,925)	0	(70,925)	(69,759)	0.9835601
21	Cable Attachments	(2,327)	(56)	(2,271)	(2,230)	0.9819463
22	Other Deferred Credits & Debits	(44,453)	(1,070)	(43,383)	(42,592)	0.9817671
23	TOTAL WORKING CAPITAL	163,620	8,424	155,196	151,120	0.9737364
24	TOTAL ADJUSTED RATE BASE	2,197,837	278,068	1,919,769	1,883,901	0.9813165

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide the depreciation rate and plant balances for each account or sub-account to which a separate depreciation rate is prescribed. (Include Amortization/Recovery schedule amounts).

Type of Data Shown:
X Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
___ Historical Year Ended 12/31/12
Witness: S. D. Ritenour

(000's)

(1) Line No.	(2) Account/ Sub-account Number	(3) Account/ Sub-account Title	(4) Depreciation Rate	(5) Plant Balance Beg. of Year	(6) Total Plant Added	(7) Total Plant Retired	(8) Adjustments or Transfers	(9) Plant Balance End of Year	(10) 13-Month Average
1		Steam Plant - Depreciable							
2		Crist Plant	3.5	1,493,707	68,293	(5,447)	0	1,556,554	1,506,349
3		Scholz Plant	4.1	30,795	5,420	(20)	0	36,196	31,253
4		Smith Plant	3.3	176,812	7,915	(1,295)	0	183,432	177,872
5		Daniel Plant	2.8	261,983	3,733	(135)	0	265,581	264,455
6	310.2	Daniel Easements	1.4	77	0	0	0	77	77
7	311	Daniel Railroad Track	1.5	2,783	26	(1)	0	2,808	2,800
8		Scherer Plant	2.0	370,735	14,793	(459)	0	385,070	373,873
9	317	ARO	N/A	7,393	0	0	0	7,393	7,393
10		Total Steam Plant - Depreciable		2,344,287	100,181	(7,356)	0	2,437,111	2,364,073
11		Steam Plant - Amortizable							
12	312	Base Coal	N/A	321	0	0	0	321	321
13	316	Prod. Plt. Furn. & Equip. - 5 Year	N/A	178	0	(55)	0	123	170
14	316	Prod. Plt. Furn. & Equip. - 7 Year	N/A	4,725	0	(279)	0	4,447	4,521
15		Daniel Cooling Lake	N/A	8,954	0	0	0	8,954	8,954
16		Total Steam Plant - Amortizable		14,179	0	(334)	0	13,846	13,967
17		Total Steam Plant		2,358,466	100,181	(7,690)	0	2,450,957	2,378,040
18		Other Production Plant							
19		Pace Plant	5.3	10,816	713	(40)	0	11,488	10,883
20		Perdido Landfill	5.0	9,659	200	0	0	9,859	9,778
21		Smith CT	3.6	8,194	534	(30)	0	8,698	8,245
22		Smith CC	2.8	218,365	15,704	(880)	0	233,188	219,843
23	347	ARO	N/A	397	0	0	0	397	397
24		Total Other Production Plant		247,431	17,150	(950)	0	263,631	249,145

Totals may not add due to rounding.

Supporting Schedules: B-8, F-8

Recap Schedules: B-1

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide the depreciation rate and plant balances for each account or sub-account to which a separate depreciation rate is prescribed. (Include Amortization/Recovery schedule amounts).

Type of Data Shown:
X Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
___ Historical Year Ended 12/31/12
Witness: S. D. Ritenour

(000's)

(1) Line No.	(2) Account/ Sub-account Number	(3) Account/ Sub-account Title	(4) Depreciation Rate	(5) Plant Balance Beg. of Year	(6) Total Plant Added	(7) Total Plant Retired	(8) Adjustments or Transfers	(9) Plant Balance End of Year	(10) 13-Month Average
1		Transmission Plant							
2	350.2	Easements	1.6	13,166	0	0	0	13,166	13,166
3	352	Structures & Improvements	2.0	10,920	0	0	0	10,920	10,920
4	353	Station Equipment	2.3	158,910	19,788	(551)	0	178,146	160,891
5	354	Towers & Fixtures	2.3	43,369	0	0	0	43,369	43,369
6	355	Poles & Fixtures	3.6	144,953	9,323	0	0	154,276	149,481
7	356	Overhead Conductors & Devices	2.5	86,239	450	0	0	86,689	86,451
8	358	Underground Conductors & Devices	2.1	14,095	0	0	0	14,095	14,095
9	359	Roads & Trails	2.0	236	0	0	0	236	236
10	352	Scherer GSU	2.0	248	0	0	0	248	248
11	353	Scherer GSU	2.3	6,015	843	(24)	0	6,834	6,099
12	359.1	ARO	N/A	8	0	0	0	8	8
13		Total Transmission Plant		478,158	30,404	(575)	0	507,988	484,964
14		Distribution Plant							
15	360.2	Easements	1.8	555	380	0	0	935	742
16	361	Structures & Improvements	2.2	23,227	0	0	0	23,227	23,227
17	362	Station Equipment	2.2	225,237	5,035	(444)	0	229,828	227,516
18	364	Poles, Towers & Fixtures	5.0	130,558	8,489	(1,021)	0	138,026	134,306
19	365	Overhead Conductors & Devices	3.1	135,722	4,739	(890)	0	139,571	137,611
20	366	Underground Conduit	1.3	1,161	0	0	0	1,161	1,161
21	367	Underground Conductors & Devices	3.3	141,800	13,215	(934)	0	154,081	147,894
22	368	Line Transformers	4.0	246,879	16,147	(2,541)	0	260,485	253,853
23	369.1	Services-Overhead	3.8	53,627	928	(29)	0	54,526	54,092
24	369.2	Services-Underground	2.6	45,436	788	(25)	0	46,199	45,831
25	370	Meter	2.7	32,635	4,615	(264)	0	36,987	34,852
26	370	Meters - AMI Equipment	6.7	40,092	0	0	0	40,092	40,092
27	370	Meters - FPSC Segregated	N/A	1,770	0	0	0	1,770	1,770
28	370	Meters - Non FPSC Segregated	N/A	3,209	0	0	0	3,209	3,209
29	373	Street Lighting & Signal Systems	5.0	64,191	3,748	(1,287)	0	66,653	65,413
30	374	ARO	N/A	43	0	0	0	43	43
31		Total Distribution Plant		1,146,142	58,085	(7,434)	0	1,196,793	1,171,612

Totals may not add due to rounding.

Supporting Schedules: B-8, F-8

Recap Schedules: B-1

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide the depreciation rate and plant balances for each account or sub-account to which a separate depreciation rate is prescribed. (Include Amortization/Recovery schedule amounts).

Type of Data Shown:
X Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
___ Historical Year Ended 12/31/12
Witness: S. D. Ritenour

(000's)

(1) Line No.	(2) Account/ Sub-account Number	(3) Account/ Sub-account Title	(4) Depreciation Rate	(5) Plant Balance Beg. of Year	(6) Total Plant Added	(7) Total Plant Retired	(8) Adjustments or Transfers	(9) Plant Balance End of Year	(10) 13-Month Average
1		General Plant - Depreciable							
2	390	Structures & Improvements	2.3	79,315	1,027	(100)	0	80,242	79,830
3	392.2	Light Trucks	9.3	7,180	860	(386)	0	7,654	7,322
4	392.3	Heavy Trucks	7.9	22,595	2,341	(1,052)	0	23,885	22,980
5	392.4	Trailers	4.8	1,272	139	(62)	0	1,349	1,295
6	396	Power Operated Equipment	4.7	865	0	0	0	865	865
7	397	Communications Equipment	6.3	18,477	2,365	(25)	0	20,817	19,509
8	399.1	ARO	N/A	195	0	0	0	195	195
9		Total General Plant - Depreciable		129,900	6,732	(1,625)	0	135,007	131,996
10		General Plant - Amortizable							
11	391	Office Furn. & Equip. - 5 Year	N/A	2,494	151	(1,095)	0	1,549	1,663
12	391	Office Furn. & Equip. - 7 Year	N/A	2,585	233	(822)	0	1,997	2,051
13	392	Transport.-Marine & Other - 5 Year	N/A	214	0	0	0	214	214
14	393	Stores Equipment - 7 Year	N/A	1,422	92	(511)	0	1,004	1,018
15	394	Tools, Shop & Garage Equip. - 7 Year	N/A	4,042	266	(8)	0	4,300	4,156
16	395	Laboratory Equipment - 7 Year	N/A	3,212	583	(333)	0	3,462	3,142
17	397	Communications Equipment - 7 Year	N/A	4,848	0	(430)	0	4,418	4,602
18	398	Miscellaneous Equipment - 7 Year	N/A	3,788	313	0	0	4,101	3,971
19	301-303	Intangible Plant - 7 Year	N/A	16,067	219	0	0	16,286	16,177
20		Total General Plant - Amortizable		38,672	1,857	(3,198)	0	37,331	36,993
21		Total General Plant		168,572	8,589	(4,823)	0	172,338	168,989
22		Non-Depreciable Plant							
23	310	Steam Land	N/A	9,423	47	0	0	9,470	9,443
24	340	Other Production Land	N/A	338	0	0	0	338	338
25	350	Transmission Land	N/A	7,148	0	0	0	7,148	7,148
26	360	Distribution Land	N/A	3,928	0	0	0	3,928	3,928
27	389	General Plant Land	N/A	7,112	0	0	0	7,112	7,112
28		Total Non-Depreciable Plant		27,950	47	0	0	27,997	27,970
29		Total	0.0	4,426,718	214,457	(21,471)	0	4,619,703	4,480,719

Totals may not add due to rounding.

Supporting Schedules: B-8, F-8

Recap Schedules: B-1

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide the monthly plant balances for each account or sub-account to which an individual depreciation rate is applied. These balances should be the ones used to compute the monthly depreciation expenses excluding any amortization/recovery schedules.

Type of Data Shown:
X Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
___ Historical Year Ended 12/31/12
Witness: S. D. Ritenour

(000's)

(1) Line No.	(2) Account/ Sub-account Number	(3) Account/ Sub-account Title	(4) 2013 December	(5) 2014 January	(6) 2014 February	(7) 2014 March	(8) 2014 April	(9) 2014 May	(10) 2014 June
1		Steam Plant - Depreciable							
2		Crist Plant	1,493,707	1,493,838	1,495,563	1,501,126	1,503,858	1,504,029	1,504,994
3		Scholz Plant	30,795	30,804	30,812	30,820	30,829	30,837	30,845
4		Smith Plant	176,812	177,007	177,202	177,396	177,341	177,536	177,410
5		Daniel Plant	261,983	261,984	264,499	264,518	264,821	264,822	264,943
6	310.2	Daniel Easements	77	77	77	77	77	77	77
7	311	Daniel Railroad Track	2,783	2,783	2,800	2,801	2,803	2,803	2,804
8		Scherer Plant	370,735	370,877	371,005	371,137	371,036	371,176	371,344
9	317	ARO	7,393	7,393	7,393	7,393	7,393	7,393	7,393
10		Total Steam Plant - Depreciable	2,344,287	2,344,764	2,349,351	2,355,269	2,358,158	2,358,673	2,359,811
11		Steam Plant - Amortizable							
12	312	Base Coal	321	321	321	321	321	321	321
13	316	Prod. Pit. Furn. & Equip. - 5 Year	178	174	174	174	174	174	174
14	316	Prod. Pit. Furn. & Equip. - 7 Year	4,725	4,725	4,488	4,488	4,488	4,488	4,488
15		Daniel Cooling Lake	8,954	8,954	8,954	8,954	8,954	8,954	8,954
16		Total Steam Plant - Amortizable	14,179	14,175	13,937	13,937	13,937	13,937	13,937
17		Total Steam Plant	2,358,466	2,358,939	2,363,288	2,369,206	2,372,095	2,372,610	2,373,748
18		Other Production Plant							
19		Pace Plant	10,816	10,818	10,821	10,827	10,830	10,832	10,835
20		Perdido Landfill	9,659	9,669	9,679	9,729	9,779	9,789	9,799
21		Smith CT	8,194	8,196	8,198	8,203	8,205	8,207	8,209
22		Smith CC	218,365	218,419	218,473	218,619	218,673	218,727	218,781
23	347	ARO	397	397	397	397	397	397	397
24		Total Other Production Plant	247,431	247,499	247,567	247,776	247,884	247,952	248,020

Totals may not add due to rounding.

Supporting Schedules:

Recap Schedules: B-1, B-7

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide the monthly plant balances for each account or sub-account to which an individual depreciation rate is applied. These balances should be the ones used to compute the monthly depreciation expenses excluding any amortization/recovery schedules.

Type of Data Shown:
X Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
___ Historical Year Ended 12/31/12
Witness: S. D. Ritenour

(000's)

(1) Line No.	(2) Account/ Sub-account Number	(3) Account/ Sub-account Title	(4) 2014 July	(5) 2014 August	(6) 2014 September	(7) 2014 October	(8) 2014 November	(9) 2014 December	(10) 13-Month Average
1		Steam Plant - Depreciable							
2		Crist Plant	1,505,130	1,505,345	1,505,786	1,506,206	1,506,397	1,556,554	1,506,349
3		Scholz Plant	30,854	30,862	30,870	30,879	30,887	36,196	31,253
4		Smith Plant	177,405	177,450	177,644	177,898	177,801	183,432	177,872
5		Daniel Plant	264,945	264,946	264,957	264,958	264,960	265,581	264,455
6	310.2	Daniel Easements	77	77	77	77	77	77	77
7	311	Daniel Railroad Track	2,804	2,804	2,804	2,804	2,804	2,808	2,800
8		Scherer Plant	374,000	374,251	375,285	376,051	378,381	385,070	373,873
9	317	ARO	7,393	7,393	7,393	7,393	7,393	7,393	7,393
10		Total Steam Plant - Depreciable	2,362,608	2,363,129	2,364,817	2,366,266	2,368,701	2,437,111	2,364,073
11		Steam Plant - Amortizable							
12	312	Base Coal	321	321	321	321	321	321	321
13	316	Prod. Pit. Furn. & Equip. - 5 Year	174	174	174	174	174	123	170
14	316	Prod. Pit. Furn. & Equip. - 7 Year	4,488	4,488	4,488	4,488	4,488	4,447	4,521
15		Daniel Cooling Lake	8,954	8,954	8,954	8,954	8,954	8,954	8,954
16		Total Steam Plant - Amortizable	13,937	13,937	13,937	13,937	13,937	13,846	13,967
17		Total Steam Plant	2,376,545	2,377,066	2,378,754	2,380,203	2,382,638	2,450,957	2,378,040
18		Other Production Plant							
19		Pace Plant	10,837	10,839	10,842	10,844	10,847	11,488	10,883
20		Perdido Landfill	9,809	9,819	9,829	9,839	9,849	9,859	9,778
21		Smith CT	8,210	8,212	8,214	8,216	8,218	8,698	8,245
22		Smith CC	218,835	218,889	218,943	218,997	219,051	233,188	219,843
23	347	ARO	397	397	397	397	397	397	397
24		Total Other Production Plant	248,089	248,157	248,225	248,293	248,362	263,631	249,145

Totals may not add due to rounding.

Supporting Schedules:

Recap Schedules: B-1, B-7

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide the monthly plant balances for each account or sub-account to which an individual depreciation rate is applied. These balances should be the ones used to compute the monthly depreciation expenses excluding any amortization/recovery schedules.

Type of Data Shown:
X Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
___ Historical Year Ended 12/31/12
Witness: S. D. Ritenour

(000's)

(1) Line No.	(2) Account/ Sub-account Number	(3) Account/ Sub-account Title	(4) 2013 December	(5) 2014 January	(6) 2014 February	(7) 2014 March	(8) 2014 April	(9) 2014 May	(10) 2014 June
1		Transmission Plant							
2	350.2	Easements	13,166	13,166	13,166	13,166	13,166	13,166	13,166
3	352	Structures & Improvements	10,920	10,920	10,920	10,920	10,920	10,920	10,920
4	353	Station Equipment	158,910	158,947	159,160	159,155	159,169	159,206	159,841
5	354	Towers & Fixtures	43,369	43,369	43,369	43,369	43,369	43,369	43,369
6	355	Poles & Fixtures	144,953	145,346	145,701	146,152	146,501	148,539	150,775
7	356	Overhead Conductors & Devices	86,239	86,271	86,299	86,336	86,364	86,407	86,456
8	358	Underground Conductors & Devices	14,095	14,095	14,095	14,095	14,095	14,095	14,095
9	359	Roads & Trails	236	236	236	236	236	236	236
10	352	Scherer GSU	248	248	248	248	248	248	248
11	353	Scherer GSU	6,015	6,016	6,025	6,025	6,026	6,027	6,054
12	359.1	ARO	8	8	8	8	8	8	8
13		Total Transmission Plant	478,158	478,622	479,228	479,710	480,101	482,221	485,167
14		Distribution Plant							
15	360.2	Easements	555	590	623	654	684	705	739
16	361	Structures & Improvements	23,227	23,227	23,227	23,227	23,227	23,227	23,227
17	362	Station Equipment	225,237	225,239	225,321	226,331	226,474	226,577	228,554
18	364	Poles, Towers & Fixtures	130,558	131,155	131,785	132,460	133,208	133,726	134,262
19	365	Overhead Conductors & Devices	135,722	135,981	136,267	136,618	137,041	137,310	137,577
20	366	Underground Conduit	1,161	1,161	1,161	1,161	1,161	1,161	1,161
21	367	Underground Conductors & Devices	141,800	142,577	143,401	144,199	144,988	146,498	148,092
22	368	Line Transformers	246,879	247,793	248,841	250,052	251,330	252,587	253,880
23	369.1	Services-Overhead	53,627	53,712	53,797	53,880	53,964	54,028	54,094
24	369.2	Services-Underground	45,436	45,508	45,580	45,651	45,722	45,776	45,832
25	370	Meter	32,635	32,908	33,287	33,691	34,104	34,499	34,897
26	370	Meters - AMI Equipment	40,092	40,092	40,092	40,092	40,092	40,092	40,092
27	370	Meters - FPSC Segregated	1,770	1,770	1,770	1,770	1,770	1,770	1,770
28	370	Meters - Non FPSC Segregated	3,209	3,209	3,209	3,209	3,209	3,209	3,209
29	373	Street Lighting & Signal Systems	64,191	64,461	64,581	64,795	65,056	65,198	65,540
30	374	ARO	43	43	43	43	43	43	43
31		Total Distribution Plant	1,146,142	1,149,427	1,152,984	1,157,833	1,162,073	1,166,406	1,172,969

Totals may not add due to rounding.

Supporting Schedules:

Recap Schedules: B-1, B-7

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide the monthly plant balances for each account or sub-account to which an individual depreciation rate is applied. These balances should be the ones used to compute the monthly depreciation expenses excluding any amortization/recovery schedules.

Type of Data Shown:
X Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
___ Historical Year Ended 12/31/12
Witness: S. D. Ritenour

(000's)

(1) Line No.	(2) Account/ Sub-account Number	(3) Account/ Sub-account Title	(4) 2014 July	(5) 2014 August	(6) 2014 September	(7) 2014 October	(8) 2014 November	(9) 2014 December	(10) 13-Month Average
1		Transmission Plant							
2	350.2	Easements	13,166	13,166	13,166	13,166	13,166	13,166	13,166
3	352	Structures & Improvements	10,920	10,920	10,920	10,920	10,920	10,920	10,920
4	353	Station Equipment	159,824	159,819	159,815	159,799	159,786	178,146	160,891
5	354	Towers & Fixtures	43,369	43,369	43,369	43,369	43,369	43,369	43,369
6	355	Poles & Fixtures	151,094	151,548	151,964	152,552	153,852	154,276	149,481
7	356	Overhead Conductors & Devices	86,481	86,518	86,551	86,601	86,655	86,689	86,451
8	358	Underground Conductors & Devices	14,095	14,095	14,095	14,095	14,095	14,095	14,095
9	359	Roads & Trails	236	236	236	236	236	236	236
10	352	Scherer GSU	248	248	248	248	248	248	248
11	353	Scherer GSU	6,053	6,053	6,053	6,052	6,052	6,834	6,099
12	359.1	ARO	8	8	8	8	8	8	8
13		Total Transmission Plant	485,494	485,980	486,426	487,046	488,386	507,988	484,964
14		Distribution Plant							
15	360.2	Easements	753	807	839	868	890	935	742
16	361	Structures & Improvements	23,227	23,227	23,227	23,227	23,227	23,227	23,227
17	362	Station Equipment	228,582	228,649	228,764	229,027	229,127	229,828	227,516
18	364	Poles, Towers & Fixtures	134,785	135,611	136,199	136,761	137,441	138,026	134,306
19	365	Overhead Conductors & Devices	137,824	138,281	138,578	138,903	139,270	139,571	137,611
20	366	Underground Conduit	1,161	1,161	1,161	1,161	1,161	1,161	1,161
21	367	Underground Conductors & Devices	149,670	150,541	151,474	152,267	153,031	154,081	147,894
22	368	Line Transformers	255,170	256,684	257,773	258,807	259,810	260,485	253,853
23	369.1	Services-Overhead	54,161	54,252	54,322	54,380	54,457	54,526	54,092
24	369.2	Services-Underground	45,889	45,966	46,026	46,075	46,140	46,199	45,831
25	370	Meter	35,231	35,652	36,112	36,385	36,691	36,987	34,852
26	370	Meters - AMI Equipment	40,092	40,092	40,092	40,092	40,092	40,092	40,092
27	370	Meters - FPSC Segregated	1,770	1,770	1,770	1,770	1,770	1,770	1,770
28	370	Meters - Non FPSC Segregated	3,209	3,209	3,209	3,209	3,209	3,209	3,209
29	373	Street Lighting & Signal Systems	65,556	65,735	66,005	66,191	66,407	66,653	65,413
30	374	ARO	43	43	43	43	43	43	43
31		Total Distribution Plant	1,177,124	1,181,679	1,185,594	1,189,165	1,192,765	1,196,793	1,171,612

Totals may not add due to rounding.

Supporting Schedules:

Recap Schedules: B-1, B-7

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide the monthly plant balances for each account or sub-account to which an individual depreciation rate is applied. These balances should be the ones used to compute the monthly depreciation expenses excluding any amortization/recovery schedules.

Type of Data Shown:
X Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
___ Historical Year Ended 12/31/12
Witness: S. D. Ritenour

(000's)

(1) Line No.	(2) Account/ Sub-account Number	(3) Account/ Sub-account Title	(4) 2013 December	(5) 2014 January	(6) 2014 February	(7) 2014 March	(8) 2014 April	(9) 2014 May	(10) 2014 June
1		General Plant - Depreciable							
2	390	Structures & Improvements	79,315	79,418	79,521	79,623	79,726	79,729	79,832
3	392.2	Light Trucks	7,180	7,185	7,190	7,204	7,204	7,204	7,204
4	392.3	Heavy Trucks	22,595	22,608	22,621	22,659	22,659	22,659	22,659
5	392.4	Trailers	1,272	1,273	1,274	1,276	1,276	1,276	1,276
6	396	Power Operated Equipment	865	865	865	865	865	865	865
7	397	Communications Equipment	18,477	18,538	18,601	18,906	19,011	19,112	19,485
8	399.1	ARO	195	195	195	195	195	195	195
9		Total General Plant - Depreciable	129,900	130,082	130,265	130,729	130,936	131,040	131,516
10		General Plant - Amortizable							
11	391	Office Furn. & Equip. - 5 Year	2,494	2,494	1,474	1,474	1,512	1,512	1,512
12	391	Office Furn. & Equip. - 7 Year	2,585	1,897	1,920	1,944	1,967	1,990	2,013
13	392	Transport.-Marine & Other - 5 Year	214	214	214	214	214	214	214
14	393	Stores Equipment - 7 Year	1,422	941	944	962	965	973	985
15	394	Tools, Shop & Garage Equip. - 7 Year	4,042	4,045	4,055	4,102	4,110	4,129	4,154
16	395	Laboratory Equipment - 7 Year	3,212	2,885	2,910	3,004	3,022	3,057	3,093
17	397	Communications Equipment - 7 Year	4,848	4,596	4,596	4,596	4,596	4,596	4,596
18	398	Miscellaneous Equipment - 7 Year	3,788	3,793	3,804	3,881	3,891	3,936	4,015
19	301-303	Intangible Plant - 7 Year	16,067	16,086	16,104	16,122	16,140	16,159	16,177
20		Total General Plant - Amortizable	38,672	36,950	36,021	36,299	36,417	36,565	36,759
21		Total General Plant	168,572	167,032	166,286	167,028	167,353	167,605	168,275
22		Non-Depreciable Plant							
23	310	Steam Land	9,423	9,423	9,423	9,423	9,423	9,447	9,447
24	340	Other Production Land	338	338	338	338	338	338	338
25	350	Transmission Land	7,148	7,148	7,148	7,148	7,148	7,148	7,148
26	360	Distribution Land	3,928	3,928	3,928	3,928	3,928	3,928	3,928
27	389	General Plant Land	7,112	7,112	7,112	7,112	7,112	7,112	7,112
28		Total Non-Depreciable Plant	27,950	27,950	27,950	27,950	27,950	27,973	27,973
29		Total	4,426,718	4,429,469	4,437,303	4,449,503	4,457,456	4,464,767	4,476,152

Totals may not add due to rounding.

Supporting Schedules:

Recap Schedules: B-1, B-7

Schedule B-8 MONTHLY PLANT BALANCES TEST YEAR - 13 MONTHS

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide the monthly plant balances for each account or sub-account to which an individual depreciation rate is applied. These balances should be the ones used to compute the monthly depreciation expenses excluding any amortization/recovery schedules.

Type of Data Shown:
X Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
___ Historical Year Ended 12/31/12
Witness: S. D. Ritenour

(000's)

(1) Line No.	(2) Account/ Sub-account Number	(3) Account/ Sub-account Title	(4) 2014 July	(5) 2014 August	(6) 2014 September	(7) 2014 October	(8) 2014 November	(9) 2014 December	(10) 13-Month Average
1		General Plant - Depreciable							
2	390	Structures & Improvements	79,934	80,037	80,088	80,140	80,191	80,242	79,830
3	392.2	Light Trucks	7,251	7,346	7,441	7,536	7,583	7,654	7,322
4	392.3	Heavy Trucks	22,788	23,046	23,304	23,562	23,691	23,885	22,980
5	392.4	Trailers	1,284	1,299	1,314	1,329	1,337	1,349	1,295
6	396	Power Operated Equipment	865	865	865	865	865	865	865
7	397	Communications Equipment	19,661	19,845	20,227	20,373	20,560	20,817	19,509
8	399.1	ARO	195	195	195	195	195	195	195
9		Total General Plant - Depreciable	131,979	132,633	133,434	134,000	134,422	135,007	131,996
10		General Plant - Amortizable							
11	391	Office Furn. & Equip. - 5 Year	1,512	1,512	1,512	1,512	1,549	1,549	1,663
12	391	Office Furn. & Equip. - 7 Year	2,037	2,060	2,072	2,083	2,095	1,997	2,051
13	392	Transport.-Marine & Other - 5 Year	214	214	214	214	214	214	214
14	393	Stores Equipment - 7 Year	992	997	1,011	1,016	1,020	1,004	1,018
15	394	Tools, Shop & Garage Equip. - 7 Year	4,168	4,184	4,234	4,247	4,264	4,300	4,156
16	395	Laboratory Equipment - 7 Year	3,117	3,151	3,275	3,308	3,350	3,462	3,142
17	397	Communications Equipment - 7 Year	4,596	4,596	4,596	4,596	4,596	4,418	4,602
18	398	Miscellaneous Equipment - 7 Year	4,058	4,075	4,089	4,096	4,099	4,101	3,971
19	301-303	Intangible Plant - 7 Year	16,195	16,213	16,232	16,250	16,268	16,286	16,177
20		Total General Plant - Amortizable	36,888	37,001	37,234	37,321	37,455	37,331	36,993
21		Total General Plant	168,867	169,634	170,668	171,321	171,877	172,338	168,989
22		Non-Depreciable Plant							
23	310	Steam Land	9,447	9,447	9,447	9,470	9,470	9,470	9,443
24	340	Other Production Land	338	338	338	338	338	338	338
25	350	Transmission Land	7,148	7,148	7,148	7,148	7,148	7,148	7,148
26	360	Distribution Land	3,928	3,928	3,928	3,928	3,928	3,928	3,928
27	389	General Plant Land	7,112	7,112	7,112	7,112	7,112	7,112	7,112
28		Total Non-Depreciable Plant	27,973	27,973	27,973	27,997	27,997	27,997	27,970
29		Total	4,484,091	4,490,490	4,497,642	4,504,026	4,512,025	4,619,703	4,480,719

Totals may not add due to rounding.

Supporting Schedules: Recap Schedules: B-1, B-7

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide the depreciation reserve balances for each account or sub-account to which an individual depreciation rate is applied. (Include Amortization/Recovery schedule amounts)

($000's)

Type of Data Shown:
_X_ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
___ Historical Year Ended 12/31/12
Witness: S. D. Ritenour

(1) Line No.	(2) Account/ Sub-account Number	(3) Account/ Sub-account Title	(4) Accumulated Depreciation Dec 2013	(5) Total Depreciation Accrued	(6) Retirements	(7) Net Salvage	(8) Adjustments or Transfers	(9) Accumulated Depreciation Dec 2014	(10) 13-Month Average
1		Steam Plant - Depreciable							
2		Crist Plant	400,078	59,035	(5,447)	(2,273)	0	451,392	425,499
3		Scholz Plant	44,495	2,064	(20)	(25)	0	46,514	45,503
4		Smith Plant	111,582	7,104	(1,295)	(320)	0	117,071	114,446
5		Daniel Plant	158,381	8,087	(135)	(136)	0	166,197	162,282
6	310.2	Daniel Easements	42	1	0	0	0	43	42
7	311	Daniel Railroad Track	1,374	42	(1)	(1)	0	1,415	1,394
8		Scherer Plant	122,111	7,558	(459)	(391)	0	128,819	125,530
9	317	ARO	1,561	0	0	0	0	1,561	1,561
10		Total Steam Plant - Depreciable	839,623	83,890	(7,356)	(3,146)	0	913,011	876,257
11		Steam Plant - Amortizable							
12	312	Base Coal	321	0	0	0	0	321	321
13	316	Prod. Plt. Furn. & Equip. - 5 Year	107	35	(55)	0	0	87	117
14	316	Prod. Plt. Furn. & Equip. - 7 Year	2,333	645	(279)	0	0	2,699	2,453
15		Daniel Cooling Lake	8,954	0	0	0	0	8,954	8,954
16		Total Steam Plant - Amortizable	11,716	680	(334)	0	0	12,062	11,846
17		Total Steam Plant	851,339	84,570	(7,690)	(3,146)	0	925,073	888,103
18		Other Production Plant							
19		Pace Plant	7,311	591	(40)	(11)	0	7,851	7,581
20		Perdido Landfill	811	489	0	0	0	1,300	1,055
21		Smith CT	3,162	299	(30)	(8)	0	3,423	3,292
22		Smith CC	10,377	6,404	(880)	(241)	0	15,660	13,011
23	347	ARO	290	0	0	0	0	290	290
24		Total Other Production Plant	21,951	7,783	(950)	(260)	0	28,524	25,228

Totals may not add due to rounding.

Supporting Schedules: B-10, F-8

Recap Schedules: B-1

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide the depreciation reserve balances for each account or sub-account to which an individual depreciation rate is applied. (Include Amortization/Recovery schedule amounts)

($000's)

Type of Data Shown:
_X_ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
___ Historical Year Ended 12/31/12
Witness: S. D. Ritenour

(1) Line No.	(2) Account/ Sub-account Number	(3) Account/ Sub-account Title	(4) Accumulated Depreciation Dec 2013	(5) Total Depreciation Accrued	(6) Retirements	(7) Net Salvage	(8) Adjustments or Transfers	(9) Accumulated Depreciation Dec 2014	(10) 13-Month Average
1		Transmission Plant							
2	350.2	Easements	6,711	211	0	0	0	6,921	6,816
3	352	Structures & Improvements	3,418	218	0	0	0	3,636	3,527
4	353	Station Equipment	28,551	3,667	(551)	(16)	0	31,651	30,155
5	354	Towers & Fixtures	25,123	997	0	0	0	26,121	25,622
6	355	Poles & Fixtures	23,622	5,367	0	(150)	0	28,839	26,206
7	356	Overhead Conductors & Devices	25,192	2,161	0	0	0	27,353	26,272
8	358	Underground Conductors & Devices	7,530	296	0	0	0	7,826	7,678
9	359	Roads & Trails	38	5	0	0	0	43	40
10	352	Scherer GSU	149	5	0	0	0	154	152
11	353	Scherer GSU	2,207	139	(24)	(1)	0	2,321	2,266
12	359.1	ARO	5	0	0	0	0	5	5
13		Total Transmission Plant	122,546	13,066	(575)	(167)	0	134,870	128,739
14		Distribution Plant							
15	360.2	Easements	29	13	0	0	0	42	35
16	361	Structures & Improvements	7,640	511	0	0	0	8,151	7,896
17	362	Station Equipment	59,218	5,001	(444)	(225)	0	63,550	61,351
18	364	Poles, Towers & Fixtures	66,552	6,700	(1,021)	(718)	0	71,513	69,037
19	365	Overhead Conductors & Devices	47,160	4,261	(890)	(560)	0	49,970	48,588
20	366	Underground Conduit	793	15	0	0	0	809	801
21	367	Underground Conductors & Devices	51,084	4,863	(934)	(413)	0	54,600	52,879
22	368	Line Transformers	89,549	10,132	(2,541)	(455)	0	96,685	93,153
23	369.1	Services-Overhead	33,024	2,054	(29)	(32)	0	35,016	34,016
24	369.2	Services-Underground	16,452	1,191	(25)	(28)	0	17,590	17,019
25	370	Meter	1,277	936	(264)	(15)	0	1,935	1,590
26	370	Meters - AMI Equipment	9,689	2,686	0	0	0	12,375	11,032
27	370	Meters - FPSC Segregated	1,770	0	0	0	0	1,770	1,770
28	370	Meters - Non FPSC Segregated	3,572	0	0	0	0	3,572	3,572
29	373	Street Lighting & Signal Systems	32,848	3,265	(1,287)	(281)	0	34,546	33,641
30	374	ARO	25	0	0	0	0	25	25
31		Total Distribution Plant	420,682	41,629	(7,434)	(2,727)	0	452,150	436,407

Totals may not add due to rounding.

Supporting Schedules: B-10, F-8

Recap Schedules: B-1

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide the depreciation reserve balances for each account or sub-account to which an individual depreciation rate is applied. (Include Amortization/Recovery schedule amounts)

($000's)

Type of Data Shown:
X Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
___ Historical Year Ended 12/31/12
Witness: S. D. Ritenour

(1) Line No.	(2) Account/ Sub-account Number	(3) Account/ Sub-account Title	(4) Accumulated Depreciation Dec 2013	(5) Total Depreciation Accrued	(6) Retirements	(7) Net Salvage	(8) Adjustments or Transfers	(9) Accumulated Depreciation Dec 2014	(10) 13-Month Average
1		General Plant - Depreciable							
2	390	Structures & Improvements	27,012	1,835	(100)	(20)	0	28,727	27,856
3	392.2	Light Trucks	3,514	678	(386)	26	0	3,832	3,742
4	392.3	Heavy Trucks	12,749	1,809	(1,052)	70	0	13,577	13,354
5	392.4	Trailers	661	62	(62)	4	0	665	674
6	396	Power Operated Equipment	513	41	0	0	0	554	533
7	397	Communications Equipment	6,837	1,222	(25)	(4)	0	8,031	7,428
8	399.1	ARO	118	0	0	0	0	118	118
9		Total General Plant - Depreciable	51,404	5,648	(1,625)	77	0	55,504	53,706
10		General Plant - Amortizable							
11	391	Office Furn. & Equip. - 5 Year	1,791	316	(1,095)	0	0	1,012	1,036
12	391	Office Furn. & Equip. - 7 Year	1,448	255	(822)	0	0	881	911
13	392	Transport.-Marine & Other - 5 Year	90	43	0	0	0	133	111
14	393	Stores Equipment - 7 Year	802	134	(511)	0	0	426	422
15	394	Tools, Shop & Garage Equip. - 7 Year	1,302	577	(8)	0	0	1,871	1,590
16	395	Laboratory Equipment - 7 Year	1,385	411	(333)	0	0	1,463	1,283
17	397	Communications Equipment - 7 Year	2,128	636	(430)	0	0	2,334	2,202
18	398	Miscellaneous Equipment - 7 Year	2,226	541	0	0	0	2,767	2,497
19	301-303	Intangible Plant - 7 Year	6,168	2,294	0	0	0	8,462	7,315
20		Total General Plant - Amortizable	17,338	5,208	(3,198)	0	0	19,348	17,366
21		Total General Plant	68,742	10,856	(4,823)	77	0	74,852	71,072
22		Total	1,485,261	157,904	(21,471)	(6,223)	0	1,615,470	1,549,548

Totals may not add due to rounding.

Supporting Schedules: B-10, F-8

Recap Schedules: B-1

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide the monthly reserve balances for each account or sub-account to which an individual depreciation rate is applied.

($000's)

Type of Data Shown:
_X_ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
___ Historical Year Ended 12/31/12
Witness: S. D. Ritenour

(1) Line No.	(2) Account Sub-account Number	(3) Account Sub-account Title	(4) 2013 December	(5) 2014 January	(6) 2014 February	(7) 2014 March	(8) 2014 April	(9) 2014 May	(10) 2014 June
1		Steam Plant - Depreciable							
2		Crist Plant	400,078	404,724	407,446	410,746	415,370	420,129	424,964
3		Scholz Plant	44,495	44,665	44,835	45,005	45,176	45,346	45,491
4		Smith Plant	111,582	112,134	112,717	113,240	113,374	113,927	114,341
5		Daniel Plant	158,381	159,046	159,710	160,372	160,974	161,645	162,241
6	310.2	Daniel Easements	42	42	42	42	42	42	42
7	311	Daniel Railroad Track	1,374	1,378	1,381	1,385	1,388	1,391	1,394
8		Scherer Plant	122,111	122,737	123,363	123,990	124,315	124,942	125,505
9	317	ARO	1,561	1,561	1,561	1,561	1,561	1,561	1,561
10		Total Steam Plant - Depreciable	839,623	846,286	851,056	856,340	862,200	868,984	875,539
11		Steam Plant - Amortizable							
12	312	Base Coal	321	321	321	321	321	321	321
13	316	Prod. Pit. Furn. & Equip. - 5 Year	107	106	109	112	115	117	120
14	316	Prod. Pit. Furn. & Equip. - 7 Year	2,333	2,389	2,207	2,260	2,314	2,367	2,420
15		Daniel Cooling Lake	8,954	8,954	8,954	8,954	8,954	8,954	8,954
16		Total Steam Plant - Amortizable	11,716	11,770	11,591	11,648	11,704	11,760	11,816
17		Total Steam Plant	851,339	858,056	862,647	867,988	873,904	880,744	887,355
18		Other Production Plant							
19		Pace Plant	7,311	7,356	7,402	7,443	7,488	7,534	7,580
20		Perdido Landfill	811	852	892	932	973	1,013	1,054
21		Smith CT	3,162	3,184	3,206	3,225	3,247	3,269	3,291
22		Smith CC	10,377	10,829	11,281	11,632	12,084	12,537	12,990
23	347	ARO	290	290	290	290	290	290	290
24		Total Other Production Plant	21,951	22,511	23,071	23,521	24,082	24,643	25,205

Totals may not add due to rounding.

Supporting Schedules:

Recap Schedules: B-1, B-9

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide the monthly reserve balances for each account or sub-account to which an individual depreciation rate is applied.

Type of Data Shown:
_X_ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
___ Historical Year Ended 12/31/12
Witness: S. D. Ritenour

($000's)

(1) Line No.	(2) Account Sub-account Number	(3) Account Sub-account Title	(4) 2014 July	(5) 2014 August	(6) 2014 September	(7) 2014 October	(8) 2014 November	(9) 2014 December	(10) 13-Month Average
1		Steam Plant - Depreciable							
2		Crist Plant	429,671	434,549	439,437	444,277	448,703	451,392	425,499
3		Scholz Plant	45,662	45,832	46,002	46,173	46,343	46,514	45,503
4		Smith Plant	114,825	115,409	115,965	116,492	116,719	117,071	114,446
5		Daniel Plant	162,912	163,584	164,203	164,866	165,530	166,197	162,282
6	310.2	Daniel Easements	42	42	42	42	43	43	42
7	311	Daniel Railroad Track	1,398	1,401	1,404	1,408	1,411	1,415	1,394
8		Scherer Plant	126,132	126,763	127,280	127,747	128,192	128,819	125,530
9	317	ARO	1,561	1,561	1,561	1,561	1,561	1,561	1,561
10		Total Steam Plant - Depreciable	882,203	889,141	895,895	902,566	908,502	913,011	876,257
11		Steam Plant - Amortizable							
12	312	Base Coal	321	321	321	321	321	321	321
13	316	Prod. Pit. Furn. & Equip. - 5 Year	123	126	129	132	135	87	117
14	316	Prod. Plt. Furn. & Equip. - 7 Year	2,474	2,527	2,580	2,634	2,687	2,699	2,453
15		Daniel Cooling Lake	8,954	8,954	8,954	8,954	8,954	8,954	8,954
16		Total Steam Plant - Amortizable	11,873	11,929	11,985	12,041	12,097	12,062	11,846
17		Total Steam Plant	894,076	901,070	907,880	914,607	920,599	925,073	888,103
18		Other Production Plant							
19		Pace Plant	7,625	7,671	7,717	7,762	7,808	7,851	7,581
20		Perdido Landfill	1,095	1,136	1,177	1,218	1,259	1,300	1,055
21		Smith CT	3,314	3,336	3,358	3,380	3,402	3,423	3,292
22		Smith CC	13,443	13,896	14,349	14,803	15,256	15,660	13,011
23	347	ARO	290	290	290	290	290	290	290
24		Total Other Production Plant	25,767	26,328	26,890	27,452	28,015	28,524	25,228

Totals may not add due to rounding.

Supporting Schedules:

Recap Schedules: B-1, B-9

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide the monthly reserve balances for each account or sub-account to which an individual depreciation rate is applied.

($000's)

Type of Data Shown:
_X_ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
___ Historical Year Ended 12/31/12
Witness: S. D. Ritenour

(1) Line No.	(2) Account Sub-account Number	(3) Account Sub-account Title	(4) 2013 December	(5) 2014 January	(6) 2014 February	(7) 2014 March	(8) 2014 April	(9) 2014 May	(10) 2014 June
1		Transmission Plant							
2	350.2	Easements	6,711	6,728	6,746	6,763	6,781	6,799	6,816
3	352	Structures & Improvements	3,418	3,436	3,454	3,472	3,491	3,509	3,527
4	353	Station Equipment	28,551	28,820	29,088	29,358	29,627	29,896	30,165
5	354	Towers & Fixtures	25,123	25,206	25,289	25,372	25,456	25,539	25,622
6	355	Poles & Fixtures	23,622	24,052	24,473	24,895	25,319	25,738	26,179
7	356	Overhead Conductors & Devices	25,192	25,372	25,552	25,731	25,911	26,091	26,271
8	358	Underground Conductors & Devices	7,530	7,555	7,580	7,604	7,629	7,654	7,678
9	359	Roads & Trails	38	38	39	39	39	40	40
10	352	Scherer GSU	149	149	150	150	151	151	152
11	353	Scherer GSU	2,207	2,217	2,227	2,237	2,247	2,257	2,267
12	359.1	ARO	5	5	5	5	5	5	5
13		Total Transmission Plant	122,546	123,579	124,602	125,628	126,655	127,677	128,722
14		Distribution Plant							
15	360.2	Easements	29	30	31	32	33	34	35
16	361	Structures & Improvements	7,640	7,683	7,726	7,768	7,811	7,853	7,896
17	362	Station Equipment	59,218	59,572	59,901	60,260	60,608	60,956	61,313
18	364	Poles, Towers & Fixtures	66,552	66,959	67,360	67,775	68,200	68,663	69,080
19	365	Overhead Conductors & Devices	47,160	47,402	47,634	47,875	48,123	48,401	48,639
20	366	Underground Conduit	793	795	796	797	799	800	801
21	367	Underground Conductors & Devices	51,084	51,397	51,693	51,991	52,320	52,620	52,903
22	368	Line Transformers	89,549	90,158	90,774	91,366	91,995	92,657	93,259
23	369.1	Services-Overhead	33,024	33,187	33,352	33,516	33,682	33,848	34,014
24	369.2	Services-Underground	16,452	16,545	16,639	16,733	16,827	16,922	17,018
25	370	Meter	1,277	1,333	1,386	1,433	1,476	1,520	1,570
26	370	Meters - AMI Equipment	9,689	9,913	10,137	10,361	10,584	10,808	11,032
27	370	Meters - FPSC Segregated	1,770	1,770	1,770	1,770	1,770	1,770	1,770
28	370	Meters - Non FPSC Segregated	3,572	3,572	3,572	3,572	3,572	3,572	3,572
29	373	Street Lighting & Signal Systems	32,848	33,030	33,107	33,218	33,441	33,556	33,751
30	374	ARO	25	25	25	25	25	25	25
31		Total Distribution Plant	420,682	423,372	425,903	428,494	431,267	434,006	436,679

Totals may not add due to rounding.

Supporting Schedules:

Recap Schedules: B-1, B-9

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide the monthly reserve balances for each account or sub-account to which an individual depreciation rate is applied.

($000's)

Type of Data Shown:
_X Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
___ Historical Year Ended 12/31/12
Witness: S. D. Ritenour

(1) Line No.	(2) Account Sub-account Number	(3) Account Sub-account Title	(4) 2014 July	(5) 2014 August	(6) 2014 September	(7) 2014 October	(8) 2014 November	(9) 2014 December	(10) 13-Month Average
1		Transmission Plant							
2	350.2	Easements	6,834	6,851	6,869	6,886	6,904	6,921	6,816
3	352	Structures & Improvements	3,545	3,563	3,582	3,600	3,618	3,636	3,527
4	353	Station Equipment	30,435	30,706	30,975	31,236	31,506	31,651	30,155
5	354	Towers & Fixtures	25,705	25,788	25,871	25,954	26,037	26,121	25,622
6	355	Poles & Fixtures	26,626	27,075	27,510	27,952	28,394	28,839	26,206
7	356	Overhead Conductors & Devices	26,451	26,632	26,812	26,992	27,173	27,353	26,272
8	358	Underground Conductors & Devices	7,703	7,728	7,752	7,777	7,802	7,826	7,678
9	359	Roads & Trails	41	41	41	42	42	43	40
10	352	Scherer GSU	152	152	153	153	154	154	152
11	353	Scherer GSU	2,277	2,287	2,297	2,307	2,317	2,321	2,266
12	359.1	ARO	5	5	5	5	5	5	5
13		Total Transmission Plant	129,774	130,827	131,867	132,904	133,951	134,870	128,739
14		Distribution Plant							
15	360.2	Easements	36	37	38	40	41	42	35
16	361	Structures & Improvements	7,939	7,981	8,024	8,066	8,109	8,151	7,896
17	362	Station Equipment	61,698	62,056	62,448	62,814	63,174	63,550	61,351
18	364	Poles, Towers & Fixtures	69,505	69,869	70,258	70,677	71,069	71,513	69,037
19	365	Overhead Conductors & Devices	48,875	49,066	49,275	49,505	49,712	49,970	48,588
20	366	Underground Conduit	802	804	805	806	807	809	801
21	367	Underground Conductors & Devices	53,181	53,503	53,744	54,024	54,373	54,600	52,879
22	368	Line Transformers	93,844	94,369	94,854	95,416	96,063	96,685	93,153
23	369.1	Services-Overhead	34,182	34,347	34,514	34,682	34,849	35,016	34,016
24	369.2	Services-Underground	17,114	17,208	17,303	17,399	17,495	17,590	17,019
25	370	Meter	1,641	1,689	1,736	1,800	1,876	1,935	1,590
26	370	Meters - AMI Equipment	11,256	11,480	11,704	11,927	12,151	12,375	11,032
27	370	Meters - FPSC Segregated	1,770	1,770	1,770	1,770	1,770	1,770	1,770
28	370	Meters - Non FPSC Segregated	3,572	3,572	3,572	3,572	3,572	3,572	3,572
29	373	Street Lighting & Signal Systems	33,620	33,785	33,975	34,136	34,324	34,546	33,641
30	374	ARO	25	25	25	25	25	25	25
31		Total Distribution Plant	439,060	441,561	444,045	446,659	449,412	452,150	436,407

Totals may not add due to rounding.

Supporting Schedules:

Recap Schedules: B-1, B-9

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide the monthly reserve balances for each account or sub-account to which an individual depreciation rate is applied.

($000's)

Type of Data Shown:
_X_ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
___ Historical Year Ended 12/31/12
Witness: S. D. Ritenour

(1) Line No.	(2) Account Sub-account Number	(3) Account Sub-account Title	(4) 2013 December	(5) 2014 January	(6) 2014 February	(7) 2014 March	(8) 2014 April	(9) 2014 May	(10) 2014 June
1		General Plant - Depreciable							
2	390	Structures & Improvements	27,012	27,164	27,315	27,466	27,618	27,667	27,817
3	392.2	Light Trucks	3,514	3,566	3,618	3,663	3,718	3,774	3,830
4	392.3	Heavy Trucks	12,749	12,888	13,027	13,146	13,296	13,445	13,594
5	392.4	Trailers	661	665	670	673	678	683	689
6	396	Power Operated Equipment	513	517	520	523	527	530	533
7	397	Communications Equipment	6,837	6,934	7,032	7,129	7,229	7,328	7,423
8	399.1	ARO	118	118	118	118	118	118	118
9		Total General Plant - Depreciable	51,404	51,852	52,300	52,720	53,184	53,546	54,004
10		General Plant - Amortizable							
11	391	Office Furn. & Equip. - 5 Year	1,791	1,832	779	802	825	849	872
12	391	Office Furn. & Equip. - 7 Year	1,448	758	780	802	823	844	865
13	392	Transport.-Marine & Other - 5 Year	90	93	97	101	104	108	111
14	393	Stores Equipment - 7 Year	802	331	342	353	364	376	387
15	394	Tools, Shop & Garage Equip. - 7 Year	1,302	1,350	1,398	1,446	1,495	1,543	1,591
16	395	Laboratory Equipment - 7 Year	1,385	1,086	1,120	1,154	1,189	1,223	1,257
17	397	Communications Equipment - 7 Year	2,128	1,931	1,986	2,039	2,091	2,144	2,196
18	398	Miscellaneous Equipment - 7 Year	2,226	2,271	2,316	2,361	2,406	2,451	2,497
19	301-303	Intangible Plant - 7 Year	6,168	6,359	6,550	6,741	6,932	7,123	7,315
20		Total General Plant - Amortizable	17,338	16,012	15,368	15,799	16,229	16,660	17,090
21		Total General Plant	68,742	67,864	67,668	68,519	69,413	70,206	71,094
22		Total	1,485,261	1,495,382	1,503,891	1,514,150	1,525,321	1,537,277	1,549,055

Totals may not add due to rounding.

Supporting Schedules:

Recap Schedules: B-1, B-9

02

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide the monthly reserve balances for each account or sub-account to which an individual depreciation rate is applied.

Type of Data Shown:
_X_ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
___ Historical Year Ended 12/31/12
Witness: S. D. Ritenour

($000's)

(1) Line No.	(2) Account Sub-account Number	(3) Account Sub-account Title	(4) 2014 July	(5) 2014 August	(6) 2014 September	(7) 2014 October	(8) 2014 November	(9) 2014 December	(10) 13-Month Average
1		General Plant - Depreciable							
2	390	Structures & Improvements	27,966	28,117	28,269	28,421	28,574	28,727	27,856
3	392.2	Light Trucks	3,850	3,834	3,819	3,804	3,827	3,832	3,742
4	392.3	Heavy Trucks	13,645	13,599	13,554	13,511	13,568	13,577	13,354
5	392.4	Trailers	688	681	675	669	668	665	674
6	396	Power Operated Equipment	537	540	544	547	550	554	533
7	397	Communications Equipment	7,514	7,617	7,721	7,827	7,934	8,031	7,428
8	399.1	ARO	118	118	118	118	118	118	118
9		Total General Plant - Depreciable	54,318	54,507	54,700	54,898	55,240	55,504	53,706
10		General Plant - Amortizable							
11	391	Office Furn. & Equip. - 5 Year	895	919	942	965	988	1,012	1,036
12	391	Office Furn. & Equip. - 7 Year	886	908	929	950	971	881	911
13	392	Transport.-Marine & Other - 5 Year	115	118	122	125	129	133	111
14	393	Stores Equipment - 7 Year	398	409	420	431	443	426	422
15	394	Tools, Shop & Garage Equip. - 7 Year	1,639	1,687	1,735	1,783	1,831	1,871	1,590
16	395	Laboratory Equipment - 7 Year	1,292	1,326	1,360	1,394	1,429	1,463	1,283
17	397	Communications Equipment - 7 Year	2,249	2,302	2,354	2,407	2,459	2,334	2,202
18	398	Miscellaneous Equipment - 7 Year	2,542	2,587	2,632	2,677	2,722	2,767	2,497
19	301-303	Intangible Plant - 7 Year	7,506	7,697	7,888	8,079	8,271	8,462	7,315
20		Total General Plant - Amortizable	17,521	17,951	18,382	18,812	19,243	19,348	17,366
21		Total General Plant	71,839	72,458	73,082	73,710	74,483	74,852	71,072
22		Total	1,560,514	1,572,245	1,583,764	1,595,333	1,606,459	1,615,470	1,549,548

Totals may not add due to rounding.

Supporting Schedules:

Recap Schedules: B-1, B-9

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Itemize major capital additions to and retirements from electric plant in service in excess of 0.5% of the sum of the total balance of Account 101-Electric Plant in Service, and Account 106, Completed construction not Classified for the most recent calendar year, the test year minus one, the test year, and the test year plus one.

Type of Data Shown:
_X_ Projected Test Year Ended 12/31/14
_X_ Prior Year Ended 12/31/13
_X_ Historical Year Ended 12/31/12
Witnesses: S. D. Ritenour, R. W. Grove, P. C. Caldwell

($000's)

(1) Line No.	(2) Description of Additions or (Retirements)	(3) Most Recent Calendar Year 12/31/2012	(4) Test Year Minus One 12/31/2013	(5) Test Year 12/31/2014	(6) Test Year Plus One 12/31/2015
1	ADDITIONS				
2	PE 1038: ECRC-Air-Crist 6 Upgr Precip[1]	25,892	0	0	0
3	PE 1173: ECRC-Air-Crist 4-7 Sulfuric Acid Mist Control[1]	0	0	31,724	0
4	PE 1208: Crist U6 Hp/lp & U7 Lp Turbine Upgrades	67,087	0	0	0
5	PE 1279: ECRC-Air-Crist 6 Selective Catalytic Reducer[1]	174,013	504	0	0
6	PE 1438: Smith 3-Long Term Service Agreement	0	20,905	0	0
7	PE 1551: ECRC-Air-Daniel 1 & 2 Scrubber[1]	0	0	1,951	355,312
8	PE 2813: N. Brewton-Alligator Swamp 230 KV Gulf	0	0	0	34,254
9	PE 2814: Laguna Beach-Santa Rosa #2 230KV TL	3,897	0	0	27,646
10	PE 2824: Marianna-Alford 115KV Reconductor	66	21,191	0	0
11	PE 2853: Laguna & Highland City 230KV Power Supplies	18,518	21,724	0	0
12	PE 2867: Holmes Creek-Highland City 230KV	417	0	20,292	39,790
13	PE 2874: Smith-Laguna 115 KV Line Conversion to 230KV	25,454	7,280	0	0
14	TOTAL ADDITIONS	315,344	71,604	53,967	457,002
15	RETIREMENTS				
16	PE 1038: ECRC-Air-Crist 6 Upgr Precip[1]	6,236	0	0	0
17	PE 1173: ECRC-Air-Crist 4-7 Sulfuric Acid Mist Control[1]	2,777	0	0	0
18	PE 1438: Smith 3-Long Term Service Agreement	0	20,050	0	0
19	TOTAL RETIREMENTS	9,013	20,050	0	0
20	TOTAL NET ADDITIONS	306,331	51,554	53,967	457,002

21 (1) ECRC, which is excluded from retail rate base.

Supporting Schedules: B-12 Recap Schedules:

Schedule B-12 | PRODUCTION PLANT ADDITIONS | Page 1 of 1

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide production plant additions for the test year and the prior year that exceed 0.5% of Gross Plant. Presenting In-Service Additions classified as Environmental, Availability/Reliability, Heat Rate, Replace Existing Plant, Safety, Energy Conservation, Capacity, Aid to Construction, and Maintenance and Regulatory.

Type of Data Shown:
X Projected Test Year Ended 12/31/14
X Prior Year Ended 12/31/13
___ Historical Year Ended 12/31/12
Witnesses: S. D. Ritenour, R. W. Grove

($000's)

(1) Line No.	(2) Preliminary Engineering Growth Classification	(3) 2013 Amount	(4) 2014 Amount
1	Environmental		31,724
2	Availability/Reliability	20,905	
3	Heat Rate		
4	Replace Existing Plant		
5	Safety		
6	Energy Conservation		
7	Capacity		
8	Aid to Construction and Maintenance		
9	Regulatory		
10	Total In-Service Additions	20,905	31,724
11	PRODUCTION		
12	PE 1173: ECRC-Air-Crist 4-7 Sulfuric Acid Mist Control		31,724
13	PE 1438: Smith 3 - Long Term Service Agreement	20,905	
14	Total In-Service Additions	20,905	31,724

Supporting Schedules:

Recap Schedules: B-11

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: For each major construction project whose cost of completion exceeds 0.2 percent (.002) of gross plant and for smaller projects within each category shown taken as a group, provide the requested data concerning projects for the test year.

($000's)

Type of Data Shown:
X Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
___ Historical Year Ended 12/31/12
Witness: S. D. Ritenour

(1) Line No.	(2) Project Description	(3) Year End CWIP Balance 2014	(4) Est. Add'l. Project Costs	(5) Total Cost of Completion	(6) Init. Project Budget Per Construction Bid	(7) Date Construction Started	(8) Expected Completion Date	(9) Percent Complete (3)/(5)	(10) Amount of AFUDC Charged	(11) 13 Month Average Balance 2014	(12) Jurisdictional Factor	(13) Jurisdictional Amount	
1	STEAM PRODUCTION:												
2	ECRC Crist 7 Esp Upgrade	10,000	10,000	20,000	20,000	Nov-14	Mar-15	50%	-	1,154	0.9701895	1,120	(1)
3	ECRC Crist 4-7 Sulfuric Acid Mist Control	-	31,724	31,724	31,724	Jan-14	Dec-14	100%	-	15,596	0.9701895	15,131	(1)
4	ECRC Smith Cold Side Precip Conversion	8,024	1,146	9,170	9,170	Jan-14	Dec-15	88%	-	4,012	0.9701895	3,892	(1)
5	ECRC Daniel 1 SCR	8,704	127,957	136,661	136,154	Jan-14	Dec-18	6%	262	4,311	0.9701895	4,182	(1)
6	ECRC Daniel 2 SCR	7,009	99,891	106,900	111,241	Jan-14	Dec-17	7%	211	3,472	0.9701895	3,368	(1)
7	ECRC Daniel 1 Scrubber	77,433	14,946	92,379	166,246	Dec-10	Dec-15	84%	4,090	67,285	0.9701895	65,279	(1)
8	ECRC Daniel 2 Scrubber	73,716	14,567	88,283	157,024	Mar-11	Dec-15	83%	3,835	63,138	0.9701895	61,256	(1)
9	ECRC Daniel Scrubber Common	136,255	48,558	184,813	22,752	Jan-11	Dec-15	74%	6,427	105,784	0.9701895	102,631	(1)
10	ECRC Daniel 1&2 Scrubber Transmission	-	1,951	1,951	1,951	Jan-13	Feb-14	100%	14	290	0.9701895	281	(1)
11	ECRC Daniel 2 Dry Bottom Ash	4,715	14,126	18,841	21,927	Jan-14	Jun-16	25%	-	1,662	0.9701895	1,612	(1)
12	ECRC Smith New Stack For ACI/DSI	10,000	10,000	20,000	20,000	Jan-14	Dec-15	50%	-	5,000	0.9701895	4,851	(1)
13	ECRC Crist 6 Dry Bottom Ash	9,430	28,253	37,683	37,683	Jan-14	Jun-16	25%	-	3,323	0.9701895	3,224	(1)
14	Minor Projects - Scherer	2,648	N/A	N/A	N/A	Various	Various	N/A	51	6,557	0.0000000	-	(2)
15	Minor Projects - Non Scherer	37,542	N/A	N/A	N/A	Various	Various	N/A	-	32,071	0.9701895	31,115	
16	Subtotal	385,476							14,890	313,655		297,942	
17	OTHER PRODUCTION												
	ECRC Smith 3 Reclaimed Water Project	-	14,500	14,500	26,500	Nov-13	Dec-14	100%	-	9,572	0.9701895	9,287	(1)
18	Minor Projects	6	N/A	N/A	N/A	Various	Various	N/A	-	93	0.9701895	90	
19	Subtotal	6							-	9,665		9,377	

20 Note:
21 (1) Projects recoverable through ECRC are adjusted out of Rate Base on B-1.
22 (2) Projects related to Plant Scherer are wholesale related and are adjusted out of Rate Base on B-1.

23 Totals may not add due to rounding.

Supporting Schedules: Recap Schedules: B-1

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: For each major construction project whose cost of completion exceeds 0.2 percent (.002) of gross plant and for smaller projects within each category shown taken as a group, provide the requested data concerning projects for the test year.

($000's)

Type of Data Shown:
_X_ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
___ Historical Year Ended 12/31/12
Witness: S. D. Ritenour

(1) Line No.	(2) Project Description	(3) Year End CWIP Balance 2014	(4) Est. Add'l. Project Costs	(5) Total Cost of Completion	(6) Init. Project Budget Per Construction Bid	(7) Date Construction Started	(8) Expected Completion Date	(9) Percent Complete (3)/(5)	(10) Amount of AFUDC Charged	(11) 13 Month Average Balance 2014	(12) Jurisdictional Factor	(13) Jurisdictional Amount
1	TRANSMISSION PLANT:											
2	Pensacola SVC (Alligator Swamp)	11,268	5,241	16,509	16,000	Oct-13	Apr-15	68%	253	4,297	0.9727205	4,180
3	North Brewton Alligator Swamp 230 Line	26,942	7,060	34,002	35,192	Jan-13	Jun-15	79%	879	14,426	0.9727205	14,032
4	Laguna Santa Rosa 230KV New Line	14,547	5,965	20,512	22,650	Oct-13	May-15	71%	582	9,431	0.9727205	9,174
5	Laguna Santa Rosa 230KV New Substatior	6,129	4,167	10,296	18,167	Jan-13	May-15	60%	129	2,200	0.9727205	2,140
6	Panama City SVC (Highland City)	11,000	5,000	16,000	16,000	Oct-13	Apr-15	69%	-	4,192	0.9727205	4,078
7	Holmes Crk. Highland 230KV Line	38,420	1,370	39,790	36,030	Jun-13	May-15	97%	1,751	28,839	0.9727205	28,052
8	Holmes Crk. Highland 230KV Autobank	-	16,655	16,655	16,500	Oct-13	Dec-14	100%	559	8,785	0.9727205	8,545
9	Holmes Crk. Highland 230KV Cap Bank	-	2,122	2,122	2,100	Dec-13	Dec-14	100%	22	326	0.9727205	317
10	Rebuild Holmes Creek Bonifay Tap	-	1,518	1,518	1,500	Jan-14	May-14	100%	18	271	0.9727205	264
11	Minor Projects	5,633	N/A	N/A	N/A	Various	Various	N/A	-	6,426	0.9727205	6,251
12	Subtotal	113,939							4,193	79,193		77,033
13	DISTRIBUTION PLANT:											
14	Minor Projects	4,478	N/A	N/A	N/A	Various	Various	N/A	-	5,357	0.9963905	5,338
15	Subtotal	4,478							-	5,357		5,338
16	GENERAL PLANT:											
17	Minor Projects	1,533	N/A	N/A	N/A	Various	Various	N/A	-	1,533	0.9767680	1,497
18	Subtotal	1,533							-	1,533		1,497
19	TOTAL AFUDC TREATMENT (1)	400,422							19,032	312,857		
20	TOTAL ECRC TREATMENT	69,211								62,698		
21	TOTAL UPS	2,648							51	6,557		
22	TOTAL RATE BASE TREATMENT	33,152								27,290	0.9767680	26,656
23	TOTAL CWIP	505,433							19,083	409,402		

24 Note:
25 (1) Some AFUDC projects are ECRC related and will be recovered through the ECRC clause once completed.

26 Totals may not add due to rounding.

Supporting Schedules: Recap Schedules: B-1

Schedule B-14	EARNINGS TEST	Page 1 of 1
FLORIDA PUBLIC SERVICE COMMISSION COMPANY: GULF POWER COMPANY DOCKET NO.: 130140-EI	EXPLANATION: If the company proposes to include any AFUDC-eligible CWIP in rate base, provide a summary of the earnings test to determine to what extent CWIP should be included in the rate base along with a detail of assumptions. As a minimum, the data provided should show the impact on the utility's financial integrity indicators with and without the level of CWIP requested.	Type of Data Shown: _X_ Projected Test Year Ended 12/31/14 ___ Prior Year Ended 12/31/13 ___ Historical Year Ended 12/31/12 Witness: S.D. Ritenour

1 Not applicable. Gulf is not requesting the inclusion of AFUDC-eligible CWIP in rate base.

Supporting Schedules:

Recap Schedules:

Schedule B-15 | PROPERTY HELD FOR FUTURE USE - 13 MONTH AVERAGE | Page 1 of 1

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide 13 month average balances for each item of property held for future use and calculate the jurisdictional amounts for the test year. Provide the prior year if the test year is projected. Individual properties that are less than 5 percent of the account total may be aggregated.

Type of Data Shown:
_X_ Projected Test Year Ended 12/31/14
_X_ Prior Year Ended 12/31/13
___ Historical Year Ended 12/31/12
Witness: S. D. Ritenour

(1) Item No.	(2) Description of Item	(3) Prior Year 2013 13 Month Average (000's)	(4) Test Year 2014 13 Month Average (000's)	(5) Test Year Jurisdictional Factor	(6) Test Year Jurisdictional Amount (4) x (5)
1	PRODUCTION FUTURE USE				
2	Caryville	1,356	1,356	0.9702652	1,316
3	Plant Smith	711	711	0.9702652	690
4	Plant Daniel	2,917	2,917	0.9702652	2,830
5	Mossy Head Generating Site (CT)	296	296	0.9702652	287
6	North Escambia County Land	13,021	13,021	0.0000000	0
7	TOTAL PRODUCTION FUTURE USE	18,301	18,301		5,123
8	DISTRIBUTION FUTURE USE				
9	TOTAL DISTRIBUTION FUTURE USE	22	22	1.0000000	22
10	GENERAL FUTURE USE				
11	TOTAL GENERAL FUTURE USE	133	133	0.9849624	131
12	TOTAL PLANT HELD FOR FUTURE USE	18,456	18,456		5,276

Supporting Schedules:

Recap Schedules: B-1

Schedule B-16 | NUCLEAR FUEL BALANCES | Page 1 of 1

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide thirteen monthly balances of nuclear fuel accounts 120.1, 120.2, 120.3, 120.4, 120.5, and, 120.6 for the test year, and the prior year if the test year is projected.

($000's)

Type of Data Shown:
X Projected Test Year Ended 12/31/14
X Prior Year Ended 12/31/13
___ Historical Year Ended 12/31/12
Witness: M. L. Burroughs

(1) Line No.	(2) Period	(3) Nuclear Fuel in Process 120.1	(4) Stock Account 120.2	(5) Nuclear Fuel Assemblies in Reactor 120.3	(6) Nuclear Fuel Spent Fuel 120.4	(7) Accumulated Provision for Amortization 120.5	(8) Nuclear Fuel Under Capital Leases 120.6	(9) Net Nuclear Fuel (A)+(B)+(C)+(D)-(E)+(F)
1	Not applicable. Gulf does not own any nuclear facilities.							

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

EXPLANATION: Provide a schedule showing the adjusted 13 month average working capital allowance for the test year and the prior year if the test year is projected. All adjustments are to be provided by account number. Use a balance sheet method and any other methodology the company proposes to use.

Type of Data Shown:
__X__Projected Test Year Ended 12/31/14
_____Prior Year Ended 12/31/13
_____Historical Year Ended 12/31/12
Witness: S. D. Ritenour

DOCKET NO.: 130140-EI

($000s)

(1) Line No.	(2) Account No.	(3) Account Name	(4) Other Property & Investments 121 - 129 Less 121 & 122	(5) Current Assets 131 - 176	(6) Deferred Debits 182-333 thru 188s excl. 18230200	(7) Operating Reserves 228 - 230	(8) Current Liabilities 231 - 245 Less 233, 235, 238-100	(9) Deferred Credits 253 - 254 Less: 254-200, 201	(10) Total
1	Total Company Working Capital		114,281	345,902	468,604	(281,257)	(199,833)	(277,170)	170,527
2	Less: Adjustments								
3	121	[a] Non-Utility in Other Investments	13,029						13,029
4	128-922, 924	[b] Minimum Pension Funding (FAS 158) Current Assets	2,455						2,455
5	182-30820, 30830, 30840	[b] Minimum Pension Funding (FAS 158) Deferred Debits			154,167				154,167
6	228-30028, 30056, 30068	[b] Minimum Pension Funding (FAS 158) Operating Reserves				(154,167)			(154,167)
7	254-922, 924	[b] Minimum Pension Funding (FAS 158) Deferred Credits						(2,455)	(2,455)
8	182-30950, 186-923, 186-927	[b] PPA Deferred Debits			191,514				191,514
9	253-1950, 254-923, 927	[b] PPA Deferred Credits						(191,514)	(191,514)
10	182-30502-30510	[b] Hedge Assets			27,112				27,112
11	245-2110, 6110	[b] Hedge Liability					(27,112)		(27,112)
12	Included in 182	[b] Asset Retirement Obligation (FAS143) Deferred Debit			5,382				5,382
13	Included in 254s	[b] Asset Retirement Obligation (FAS 143) Deferred Credit						(14,326)	(14,326)
14	Included in 230s	[b] Asset Retirement Obligation (FAS 143) Liability				(16,055)			(16,055)
15	128-001, 002, 003	[b] Funded Property Insurance Reserve	22,726						22,726
16	Included in 228-11100s	[b] Property Insurance Reserve (funded)				(22,726)			(22,726)
17	123s	[b] Funded Portion of Def Comp Assets	2,598						2,598
18	Incl. in 253-6000F-6606F & 253-736	[b] Funded Portion of Def Comp Def Credits						(2,598)	(2,598)
19	143-800s	[b] Loans To Employees & Retirees		38					38
20	Included in 154-500	[b] AEM Inventory (ECCR)		2,466					2,466
21	158s	[b] Environmental Allowances (ECRC)		6,783					6,783
22	254-300s	[b] Environmental Allowance & Deferred Gain (ECRC)						(204)	(204)
23	171s	[b] Interest & Dividends Receivable		25					25
24	182-30122	[b] Deferred North Escambia Site Costs			5,149				5,149
25	182-30864	[b] Unamort. 2011 Rate Case Expenses			1,246				1,246
26	228-11100s	[c] Increase in Property Insurance Reserve Accrual				2,750			2,750
27	182-30859	[b] CAIR Annual NOX Allowances			624				624
28		TOTAL ADJUSTED WORKING CAPITAL	73,473	336,590	83,410	(91,059)	(172,721)	(66,073)	163,620

Supporting Schedules: B-6

Recap Schedules: B-1, B-2

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

EXPLANATION: Provide a schedule showing the adjusted 13 month average working capital allowance for the test year and the prior year if the test year is projected. All adjustments are to be provided by account number. Use a balance sheet method and any other methodology the company proposes to use.

Type of Data Shown:
__X__ Projected Test Year Ended 12/31/14
_____ Prior Year Ended 12/31/13
_____ Historical Year Ended 12/31/12
Witness: S. D. Ritenour

DOCKET NO.: 130140-EI

($000s)

(1) Line No.	(2) Account No.	(3) Account Name	(4) Other Property & Investments 121 - 129 Less 121 & 122	(5) Current Assets 131 - 176	(6) Deferred Debits 182-333 thru 188s excl. 18230200	(7) Operating Reserves 228 - 230	(8) Current Liabilities 231 - 245 Less 233, 235, 238-100	(9) Deferred Credits 253 - 254 Less: 254-200, 201	(10) Total
1	UPS								
2	151-100,330,151-23150	Fuel Stock		7,203					7,203
3	154-00004	Other Material & Supplies		2,330					2,330
4	165	Prepayments		245					245
5	Calculated	Other Working Capital		3,983	1,881	(1,471)	(4,157)	(1,590)	(1,354)
6	TOTAL COMPANY ADJUSTED WORKING CAPITAL NET OF UPS		73,473	322,829	81,529	(89,588)	(168,564)	(64,483)	155,196
7	Jurisdictional Factor		0.9835450	0.9781339	0.9810374	0.9833013	0.9817992	0.9817937	0.9737364
8	JURISDICTIONAL ADJUSTED WORKING CAPITAL		72,264	315,770	79,983	(88,092)	(165,496)	(63,309)	151,120

9 Notes:

10 [a] $ 13,029 Non-Electric Adjustment. Reference MFR B-2.
11 [b] $ (8,872) Commission Adjustment. Reference MFR B-2.
12 [c] $ 2,750 Company Adjustment. Reference MFR B-2.

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

EXPLANATION: Provide a schedule showing the adjusted 13 month average working capital allowance for the test year and the prior year if the test year is projected. All adjustments are to be provided by account number. Use a balance sheet method and any other methodology the company proposes to use.

Type of Data Shown:
____Projected Test Year Ended 12/31/14
_X_Prior Year Ended 12/31/13
____Historical Year Ended 12/31/12
Witness: S. D. Ritenour

DOCKET NO.: 130140-EI ($000s)

(1) Line No.	(2) Account No.	(3) Account Name	(4) Other Property & Investments 121 - 129 Less 121 & 122	(5) Current Assets 131 - 176	(6) Deferred Debits 182-333 thru 188s excl. 18230200	(7) Operating Reserves 228 - 230	(8) Current Liabilities 231 - 245 Less 233, 235, 238-100	(9) Deferred Credits 253 - 254 Less: 254-200, 201	(10) Total
1		Total Company Working Capital	121,609	368,222	453,853	(276,298)	(187,970)	(261,737)	217,679
2		Less: Adjustments							
3	121	[a] Non-Utility in Other Investments	13,050						13,050
4	128-922, 924	[b] Minimum Pension Funding (FAS 158) Current Assets	2,455						2,455
5	182-30820, 30830, 30840	[b] Minimum Pension Funding (FAS 158) Deferred Debits			154,167				154,167
6	228-30028, 30056, 30068	[b] Minimum Pension Funding (FAS 158) Operating Reserves				(154,167)			(154,167)
7	254-922, 924	[b] Minimum Pension Funding (FAS 158) Deferred Credits						(2,455)	(2,455)
8	182-30950, 186-923, 186-927	[b] PPA Deferred Debits			165,035				165,035
9	253-1950, 254-923, 927	[b] PPA Deferred Credits						(165,035)	(165,035)
10	182-30502-30510	[b] Hedge Assets			27,112				27,112
11	245-2110, 6110	[b] Hedge Liability					(27,112)		(27,112)
12	Included in 182	[b] Asset Retirement Obligation (FAS143) Deferred Debit			5,382				5,382
13	Included in 254s	[b] Asset Retirement Obligation (FAS 143) Deferred Credit						(14,326)	(14,326)
14	Included in 230s	[b] Asset Retirement Obligation (FAS 143) Liability				(16,055)			(16,055)
15	128-001, 002, 003	[b] Funded Property Insurance Reserve	20,681						20,681
16	Included in 228-11100s	[b] Property Insurance Reserve (funded)				(20,681)			(20,681)
17	123s	[b] Funded Portion of Def Comp Assets	2,581						2,581
18	Incl. in 253-6000F-6606F & 253-736	[b] Funded Portion of Def Comp Def Credits						(2,581)	(2,581)
19	143-800s	[b] Loans To Employees & Retirees		38					38
20	Included in 154-500	[b] AEM Inventory (ECCR)		2,787					2,787
21	158s	[b] Environmental Allowances (ECRC)		7,653					7,653
22	254-300s	[b] Environmental Allowance & Deferred Gain (ECRC)						(412)	(412)
23	171s	[b] Interest & Dividends Receivable		6					6
24	182-30122	[b] Deferred North Escambia Site Costs			5,149				5,149
25	182-30864	[b] Unamort. 2011 Rate Case Expenses			1,948				1,948
26	229-00004	[b] Accrued Provision for Refund				(116)			(116)
27	182-30859	[b] CAIR Annual NOX Allowances			839				839
28	182-30710, 30711, 30712, 30713	[b] Clause Under-Recovery Balance			1,762				1,762
29	237-09100	[b] Accrued Interest on Tax Assessment					(14)		(14)
30		TOTAL ADJUSTED WORKING CAPITAL	82,842	357,738	92,459	(85,279)	(160,844)	(76,928)	209,988

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

EXPLANATION: Provide a schedule showing the adjusted 13 month average working capital allowance for the test year and the prior year if the test year is projected. All adjustments are to be provided by account number. Use a balance sheet method and any other methodology the company proposes to use.

Type of Data Shown:
____Projected Test Year Ended 12/31/14
_X_Prior Year Ended 12/31/13
____Historical Year Ended 12/31/12
Witness: S. D. Ritenour

DOCKET NO.: 130140-EI ($000s)

(1) Line No.	(2) Account No.	(3) Account Name	(4) Other Property & Investments 121 - 129 Less 121 & 122	(5) Current Assets 131 - 176	(6) Deferred Debits 182-333 thru 188s excl. 18230200	(7) Operating Reserves 228 - 230	(8) Current Liabilities 231 - 245 Less 233, 235, 238-100	(9) Deferred Credits 253 - 254 Less: 254-200, 201	(10) Total
1	UPS								
2	151-100,330,151-23150	Fuel Stock		7,607					7,607
3	154-00004	Other Material & Supplies		2,373					2,373
4	165	Prepayments		346					346
5	Calculated	Other Working Capital		3,861	1,974	(1,143)	(3,871)	(1,851)	(1,030)
6	TOTAL COMPANY ADJUSTED WORKING CAPITAL NET OF UPS		82,842	343,551	90,485	(84,136)	(156,973)	(75,077)	200,692
7	Jurisdictional Factor		0.9835450	0.9774357	0.9806266	0.9830869	0.9817994	0.9817920	0.9739900
8	JURISDICTIONAL ADJUSTED WORKING CAPITAL		81,480	335,799	88,732	(82,713)	(154,116)	(73,710)	195,472

82

9 Notes:

10 [a] $ 13,050 Non-Electric Adjustment. Reference MFR B-2.
11 [b] $ (5,359) Commission Adjustment. Reference MFR B-2.
12 [c] $ - Company Adjustment. Reference MFR B-2.

Totals may not add due to rounding.

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide a schedule showing the adjusted 13 month average working capital allowance for the test year and the prior year if the test year is projected. All adjustments are to be provided by account number. Use a balance sheet method and any other methodology the company proposes to use.

Type of Data Shown:
____Projected Test Year Ended 12/31/14
____Prior Year Ended 12/31/13
_X_Historical Year Ended 12/31/12
Witness: S. D. Ritenour

($000s)

(1) Line No.	(2) Account No.	(3) Account Name	(4) Other Property & Investments 121 - 129 Less 121 & 122	(5) Current Assets 131 - 176	(6) Deferred Debits 182-333 thru 188s excl. 18230200	(7) Operating Reserves 228 - 230	(8) Current Liabilities 231 - 245 Less 233, 235, 238-100	(9) Deferred Credits 253 - 254 Less: 254-200, 201	(10) Total
1	Total Company Working Capital		114,168	397,274	396,472	(232,599)	(187,736)	(272,034)	215,545
2	Less: Adjustments								
3	121	[a] Non-Utility in Other Investments	13,218						13,218
4	128-922, 924	[b] Minimum Pension Funding (FAS 158) Current Assets	2,475						2,475
5	182-30820, 30830, 30840	[b] Minimum Pension Funding (FAS 158) Deferred Debits			117,959				117,959
6	228-30028, 30056, 30068	[b] Minimum Pension Funding (FAS 158) Operating Reserves				(117,959)			(117,959)
7	254-922, 924	[b] Minimum Pension Funding (FAS 158) Deferred Credits						(2,475)	(2,475)
8	182-30950, 186-923, 186-927	[b] PPA Deferred Debits			122,461				122,461
9	253-1950, 254-923, 927	[b] PPA Deferred Credits						(122,461)	(122,461)
10	182-30502-30510	[b] Hedge Assets			38,402				38,402
11	245-2110, 6110	[b] Hedge Liability					(38,402)		(38,402)
12	Included in 182	[b] Asset Retirement Obligation (FAS143) Deferred Debit			5,307				5,307
13	Included in 254s	[b] Asset Retirement Obligation (FAS 143) Deferred Credit						(14,146)	(14,146)
14	Included in 230s	[b] Asset Retirement Obligation (FAS 143) Liability				(11,293)			(11,293)
15	128-001, 002, 003	[b] Funded Property Insurance Reserve	18,495						18,495
16	Included in 228-11100s	[b] Property Insurance Reserve (funded)				(18,495)			(18,495)
17	123s	[b] Funded Portion of Def Comp Assets	2,904						2,904
18	Incl. in 253-6000F-6606F & 253-736	[b] Funded Portion of Def Comp Def Credits						(2,904)	(2,904)
19	143-800s	[b] Loans To Employees & Retirees		41					41
20	Included in 154-500	[b] AEM Inventory (ECCR)		2,332					2,332
21	158s	[b] Environmental Allowances (ECRC)		8,373					8,373
22	254-300s	[b] Environmental Allowance & Deferred Gain (ECRC)						(666)	(666)
23	171s	[b] Interest & Dividends Receivable		18					18
24	182-30122	[b] Deferred North Escambia Site Costs			8,431				8,431
25	182-30864	[b] Unamort. 2011 Rate Case Expenses			2,620				2,620
26	229-00004	[b] Accrued Provision for Refund				(782)			(782)
27	182-30859	[b] CAIR Annual NOX Allowances			1,320				1,320
28	182-30710, 30711, 30712, 30713	[b] Clause Under-Recovery Balance			2,263				2,263
29	237-09100	[b] Accrued interest on Tax Assessment					(131)		(131)
30	136s	[b] Temporary Cash Investment		99					99
31		TOTAL ADJUSTED WORKING CAPITAL	77,076	386,411	97,709	(84,070)	(149,203)	(129,382)	198,541

Supporting Schedules: B-6

Recap Schedules: B-1, B-2

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

EXPLANATION: Provide a schedule showing the adjusted 13 month average working capital allowance for the test year and the prior year if the test year is projected. All adjustments are to be provided by account number. Use a balance sheet method and any other methodology the company proposes to use.

Type of Data Shown:
____Projected Test Year Ended 12/31/14
____Prior Year Ended 12/31/13
_X_Historical Year Ended 12/31/12
Witness: S. D. Ritenour

DOCKET NO.: 130140-EI

($000s)

(1) Line No.	(2) Account No.	(3) Account Name	(4) Other Property & Investments 121 - 129 Less 121 & 122	(5) Current Assets 131 - 176	(6) Deferred Debits 182-333 thru 188s excl. 18230200	(7) Operating Reserves 228 - 230	(8) Current Liabilities 231 - 245 Less 233, 235, 238-100	(9) Deferred Credits 253 - 254 Less: 254-200, 201	(10) Total
1	UPS								
2	151-100,330,151-23150	Fuel Stock		8,951					8,951
3	154-00004	Other Material & Supplies		2,288					2,288
4	165	Prepayments		2,137					2,137
5	Calculated	Other Working Capital		4,243	2,379	(1,180)	(3,590)	(3,038)	(1,186)
6	TOTAL COMPANY ADJUSTED WORKING CAPITAL NET OF UPS		77,076	368,792	95,330	(82,890)	(145,613)	(126,344)	186,351
7	Jurisdictional Factor		0.9835450	0.9691940	0.9840344	0.9786102	0.9818011	0.9570221	0.9769414
8	JURISDICTIONAL ADJUSTED WORKING CAPITAL		75,809	357,431	93,808	(81,117)	(142,963)	(120,914)	182,054

9 Notes:

10 [a] $ 13,218 Non-Electric Adjustment. Reference MFR B-2.
11 [b] $ 3,786 Commission Adjustment. Reference MFR B-2.
12 [c] $ - Company Adjustment. Reference MFR B-2.

Totals may not add due to rounding.

Supporting Schedules: B-6

Recap Schedules: B-1, B-2

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide conventional fuel account balances in dollars and quantities for each fuel type for the test year and the two preceeding years. Include Natural Gas even though no inventory is carried. (Give units in Barrels, Tons, or MCF)

Type of Data Shown:

X Projected Test Year Ended 12/31/14

Prior Year Ended 12/31/13

Historical Year Ended 12/31/12

Witness: M. L. Burroughs, S. D. Ritenour

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
				Beginning Inventory			Receipts			Fuel Issued to Generation		
Line No.	Plant	Fuel Type	Month	Units	($000)	$/Unit	Units	($000)	$/Unit	Units	($000)	$/Unit
1	Crist	Coal (tons)	Dec-13	316,071	31,572	99.89	132,000	13,338	101.05	128,094	12,840	100.24
2	Crist	Coal (tons)	Jan-14	319,977	32,070	100.23	108,000	11,533	106.79	115,868	11,805	101.88
3	Crist	Coal (tons)	Feb-14	312,109	31,798	101.88	78,999	8,726	110.46	83,275	8,628	103.61
4	Crist	Coal (tons)	Mar-14	307,833	31,896	103.61	92,000	9,978	108.46	97,999	10,263	104.73
5	Crist	Coal (tons)	Apr-14	301,834	31,611	104.73	122,001	12,647	103.66	115,572	12,069	104.43
6	Crist	Coal (tons)	May-14	308,263	32,189	104.42	125,999	13,273	105.34	131,444	13,761	104.69
7	Crist	Coal (tons)	Jun-14	302,818	31,701	104.69	126,000	13,271	105.33	135,756	14,237	104.87
8	Crist	Coal (tons)	Jul-14	293,062	30,735	104.88	133,000	13,799	103.75	148,941	15,568	104.52
9	Crist	Coal (tons)	Aug-14	277,121	28,966	104.52	158,768	15,939	100.39	164,894	16,987	103.02
10	Crist	Coal (tons)	Sep-14	270,995	27,918	103.02	134,260	13,334	99.31	134,258	13,666	101.79
11	Crist	Coal (tons)	Oct-14	270,997	27,586	101.79	128,620	12,795	99.48	128,618	12,997	101.05
12	Crist	Coal (tons)	Nov-14	270,999	27,384	101.05	119,914	11,774	98.19	119,912	12,011	100.17
13	Crist	Coal (tons)	Dec-14	271,001	27,147	100.17	125,741	12,146	96.60	125,742	12,454	99.04

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide conventional fuel account balances in dollars and quantities for each fuel type for the test year and the two preceeding years. Include Natural Gas even though no inventory is carried. (Give units in Barrels, Tons, or MCF)

Type of Data Shown:

X Projected Test Year Ended 12/31/14

Prior Year Ended 12/31/13

Historical Year Ended 12/31/12

Witness: M. L. Burroughs, S. D. Ritenour

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
				Fuel Issues (Other)			Adjustments			Ending Inventory		
Line No.	Plant	Fuel Type	Month	Units	($000)	$/Unit	Units	($000)	$/Unit	Units	($000)	$/Unit
1	Crist	Coal (tons)	Dec-13	0	0	0.00	0	0	0.00	319,977	32,070	100.23
2	Crist	Coal (tons)	Jan-14	0	0	0.00	0	0	0.00	312,109	31,798	101.88
3	Crist	Coal (tons)	Feb-14	0	0	0.00	0	0	0.00	307,833	31,896	103.61
4	Crist	Coal (tons)	Mar-14	0	0	0.00	0	0	0.00	301,834	31,611	104.73
5	Crist	Coal (tons)	Apr-14	0	0	0.00	0	0	0.00	308,263	32,189	104.42
6	Crist	Coal (tons)	May-14	0	0	0.00	0	0	0.00	302,818	31,701	104.69
7	Crist	Coal (tons)	Jun-14	0	0	0.00	0	0	0.00	293,062	30,735	104.88
8	Crist	Coal (tons)	Jul-14	0	0	0.00	0	0	0.00	277,121	28,966	104.52
9	Crist	Coal (tons)	Aug-14	0	0	0.00	0	0	0.00	270,995	27,918	103.02
10	Crist	Coal (tons)	Sep-14	0	0	0.00	0	0	0.00	270,997	27,586	101.79
11	Crist	Coal (tons)	Oct-14	0	0	0.00	0	0	0.00	270,999	27,384	101.05
12	Crist	Coal (tons)	Nov-14	0	0	0.00	0	0	0.00	271,001	27,147	100.17
13	Crist	Coal (tons)	Dec-14	0	0	0.00	0	0	0.00	271,000	26,839	99.04
14	Total									3,778,009	387,840	
15	Crist	Coal (tons)	13 mth avg							290,616	29,834	102.66

16 Totals may not add due to rounding.

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide conventional fuel account balances in dollars and quantities for each fuel type for the test year and the two preceeding years. Include Natural Gas even though no inventory is carried. (Give units in Barrels, Tons, or MCF)

Type of Data Shown:

X Projected Test Year Ended 12/31/14

Prior Year Ended 12/31/13

Historical Year Ended 12/31/12

Witness: M. L. Burroughs, S. D. Ritenour

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
				Beginning Inventory			Receipts			Fuel Issued to Generation		
Line No.	Plant	Fuel Type	Month	Units	($000)	$/Unit	Units	($000)	$/Unit	Units	($000)	$/Unit
1	Smith	Coal (tons)	Dec-13	154,696	20,772	134.28	30,000	4,164	138.80	44,213	5,969	135.01
2	Smith	Coal (tons)	Jan-14	140,483	18,967	135.01	26,327	3,535	134.27	47,578	6,418	134.89
3	Smith	Coal (tons)	Feb-14	119,232	16,084	134.90	33,638	4,214	125.27	33,674	4,471	132.77
4	Smith	Coal (tons)	Mar-14	119,196	15,827	132.78	38,256	4,641	121.31	38,243	4,971	129.98
5	Smith	Coal (tons)	Apr-14	119,209	15,497	130.00	37,563	4,578	121.88	37,462	4,797	128.05
6	Smith	Coal (tons)	May-14	119,310	15,278	128.05	32,360	4,095	126.55	32,251	4,120	127.75
7	Smith	Coal (tons)	Jun-14	119,419	15,253	127.73	32,742	4,131	126.17	32,789	4,177	127.39
8	Smith	Coal (tons)	Jul-14	119,372	15,207	127.39	42,872	5,071	118.28	42,905	5,363	125.00
9	Smith	Coal (tons)	Aug-14	119,339	14,915	124.98	56,548	6,339	112.10	56,569	6,836	120.84
10	Smith	Coal (tons)	Sep-14	119,318	14,418	120.84	32,394	4,097	126.47	32,401	3,954	122.03
11	Smith	Coal (tons)	Oct-14	119,311	14,561	122.04	39,032	4,714	120.77	39,037	4,752	121.73
12	Smith	Coal (tons)	Nov-14	119,306	14,523	121.73	37,693	4,590	121.77	37,695	4,589	121.74
13	Smith	Coal (tons)	Dec-14	119,304	14,524	121.74	54,924	6,188	112.66	54,226	6,446	118.87

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide conventional fuel account balances in dollars and quantities for each fuel type for the test year and the two preceeding years. Include Natural Gas even though no inventory is carried. (Give units in Barrels, Tons, or MCF)

Type of Data Shown:

X Projected Test Year Ended 12/31/14

____ Prior Year Ended 12/31/13

____ Historical Year Ended 12/31/12

Witness: M. L. Burroughs, S. D. Ritenour

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
				Fuel Issues (Other)			Adjustments			Ending Inventory		
Line No.	Plant	Fuel Type	Month	Units	($000)	$/Unit	Units	($000)	$/Unit	Units	($000)	$/Unit
1	Smith	Coal (tons)	Dec-13	0	0	0.00	0	0	0.00	140,483	18,967	135.01
2	Smith	Coal (tons)	Jan-14	0	0	0.00	0	0	0.00	119,232	16,084	134.90
3	Smith	Coal (tons)	Feb-14	0	0	0.00	0	0	0.00	119,196	15,827	132.78
4	Smith	Coal (tons)	Mar-14	0	0	0.00	0	0	0.00	119,209	15,497	130.00
5	Smith	Coal (tons)	Apr-14	0	0	0.00	0	0	0.00	119,310	15,278	128.05
6	Smith	Coal (tons)	May-14	0	0	0.00	0	0	0.00	119,419	15,253	127.73
7	Smith	Coal (tons)	Jun-14	0	0	0.00	0	0	0.00	119,372	15,207	127.39
8	Smith	Coal (tons)	Jul-14	0	0	0.00	0	0	0.00	119,339	14,915	124.98
9	Smith	Coal (tons)	Aug-14	0	0	0.00	0	0	0.00	119,318	14,418	120.84
10	Smith	Coal (tons)	Sep-14	0	0	0.00	0	0	0.00	119,311	14,561	122.04
11	Smith	Coal (tons)	Oct-14	0	0	0.00	0	0	0.00	119,306	14,523	121.73
12	Smith	Coal (tons)	Nov-14	0	0	0.00	0	0	0.00	119,304	14,524	121.74
13	Smith	Coal (tons)	Dec-14	0	0	0.00	0	0	0.00	120,002	14,266	118.88
14	Total									1,572,801	199,320	
15	Smith	Coal (tons)	13 mth avg							120,985	15,332	126.73

16 Totals may not add due to rounding.

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide conventional fuel account balances in dollars and quantities for each fuel type for the test year and the two preceeding years. Include Natural Gas even though no inventory is carried. (Give units in Barrels, Tons, or MCF)

Type of Data Shown:

X Projected Test Year Ended 12/31/14

Prior Year Ended 12/31/13

Historical Year Ended 12/31/12

Witness: M. L. Burroughs, S. D. Ritenour

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
				Beginning Inventory			Receipts			Fuel Issued to Generation		
Line No.	Plant	Fuel Type	Month	Units	($000)	$/Unit	Units	($000)	$/Unit	Units	($000)	$/Unit
1	Scholz	Coal (tons)	Dec-13	25,868	2,249	86.94	1	0	0.00	1,197	104	86.88
2	Scholz	Coal (tons)	Jan-14	24,672	2,145	86.94	1,869	151	80.79	2,442	212	86.81
3	Scholz	Coal (tons)	Feb-14	24,099	2,084	86.48	2,447	196	80.10	2,447	210	85.82
4	Scholz	Coal (tons)	Mar-14	24,099	2,070	85.90	2,229	179	80.31	2,230	191	85.65
5	Scholz	Coal (tons)	Apr-14	24,098	2,058	85.40	0	0	0.00	0	0	0.00
6	Scholz	Coal (tons)	May-14	24,098	2,058	85.40	0	0	0.00	0	0	0.00
7	Scholz	Coal (tons)	Jun-14	24,098	2,058	85.40	0	0	0.00	0	0	0.00
8	Scholz	Coal (tons)	Jul-14	24,098	2,058	85.40	0	0	0.00	0	0	0.00
9	Scholz	Coal (tons)	Aug-14	24,098	2,058	85.40	4,915	395	80.37	4,915	416	84.64
10	Scholz	Coal (tons)	Sep-14	24,098	2,037	84.53	2,460	197	80.08	2,460	207	84.15
11	Scholz	Coal (tons)	Oct-14	24,098	2,027	84.11	0	0	0.00	0	0	0.00
12	Scholz	Coal (tons)	Nov-14	24,098	2,027	84.11	1,208	96	79.47	1,208	101	83.61
13	Scholz	Coal (tons)	Dec-14	24,098	2,022	83.91	3,370	271	80.42	2,466	206	83.54

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide conventional fuel account balances in dollars and quantities for each fuel type for the test year and the two preceeding years. Include Natural Gas even though no inventory is carried. (Give units in Barrels, Tons, or MCF)

Type of Data Shown:

X Projected Test Year Ended 12/31/14

____ Prior Year Ended 12/31/13

____ Historical Year Ended 12/31/12

Witness: M. L. Burroughs, S. D. Ritenour

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
				Fuel Issues (Other)			Adjustments			Ending Inventory		
Line No.	Plant	Fuel Type	Month	Units	($000)	$/Unit	Units	($000)	$/Unit	Units	($000)	$/Unit
1	Scholz	Coal (tons)	Dec-13	0	0	0.00	0	0	0.00	24,672	2,145	86.94
2	Scholz	Coal (tons)	Jan-14	0	0	0.00	0	0	0.00	24,099	2,084	86.48
3	Scholz	Coal (tons)	Feb-14	0	0	0.00	0	0	0.00	24,099	2,070	85.90
4	Scholz	Coal (tons)	Mar-14	0	0	0.00	0	0	0.00	24,098	2,058	85.40
5	Scholz	Coal (tons)	Apr-14	0	0	0.00	0	0	0.00	24,098	2,058	85.40
6	Scholz	Coal (tons)	May-14	0	0	0.00	0	0	0.00	24,098	2,058	85.40
7	Scholz	Coal (tons)	Jun-14	0	0	0.00	0	0	0.00	24,098	2,058	85.40
8	Scholz	Coal (tons)	Jul-14	0	0	0.00	0	0	0.00	24,098	2,058	85.40
9	Scholz	Coal (tons)	Aug-14	0	0	0.00	0	0	0.00	24,098	2,037	84.53
10	Scholz	Coal (tons)	Sep-14	0	0	0.00	0	0	0.00	24,098	2,027	84.11
11	Scholz	Coal (tons)	Oct-14	0	0	0.00	0	0	0.00	24,098	2,027	84.11
12	Scholz	Coal (tons)	Nov-14	0	0	0.00	0	0	0.00	24,098	2,022	83.91
13	Scholz	Coal (tons)	Dec-14	0	0	0.00	0	0	0.00	25,002	2,087	83.47
14	Total									314,754	26,789	
15	Scholz	Coal (tons)	13 mth avg							24,212	2,061	85.12

16 Totals may not add due to rounding.

Supporting Schedules:

Recap Schedules:

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FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide conventional fuel account balances in dollars and quantities for each fuel type for the test year and the two preceeding years. Include Natural Gas even though no inventory is carried. (Give units in Barrels, Tons, or MCF)

Type of Data Shown:

X Projected Test Year Ended 12/31/14

Prior Year Ended 12/31/13

Historical Year Ended 12/31/12

Witness: M. L. Burroughs, S. D. Ritenour

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
				Beginning Inventory			Receipts			Fuel Issued to Generation		
Line No.	Plant	Fuel Type	Month	Units	($000)	$/Unit	Units	($000)	$/Unit	Units	($000)	$/Unit
1	Daniel	Coal (tons)	Dec-13	343,052	39,302	114.57	28,074	3,600	128.23	9,839	1,137	115.56
2	Daniel	Coal (tons)	Jan-14	361,287	41,765	115.60	6,650	409	61.50	45,133	5,173	114.62
3	Daniel	Coal (tons)	Feb-14	322,804	37,001	114.62	19,951	1,225	61.40	11,801	1,316	111.52
4	Daniel	Coal (tons)	Mar-14	330,954	36,910	111.53	19,950	1,215	60.90	18,575	2,018	108.64
5	Daniel	Coal (tons)	Apr-14	332,329	36,107	108.65	19,950	1,220	61.15	24,088	2,552	105.94
6	Daniel	Coal (tons)	May-14	328,191	34,775	105.96	19,950	1,225	61.40	19,139	1,979	103.40
7	Daniel	Coal (tons)	Jun-14	329,002	34,021	103.41	39,900	2,451	61.43	67,929	6,716	98.87
8	Daniel	Coal (tons)	Jul-14	300,973	29,756	98.87	39,900	2,456	61.55	87,358	8,255	94.50
9	Daniel	Coal (tons)	Aug-14	253,515	23,957	94.50	52,099	3,844	73.78	96,045	8,737	90.97
10	Daniel	Coal (tons)	Sep-14	209,569	19,064	90.97	52,100	3,873	74.34	72,157	6,325	87.66
11	Daniel	Coal (tons)	Oct-14	189,512	16,612	87.66	39,900	2,492	62.46	48,245	4,018	83.28
12	Daniel	Coal (tons)	Nov-14	181,167	15,086	83.27	19,950	1,244	62.36	8,070	655	81.16
13	Daniel	Coal (tons)	Dec-14	193,047	15,675	81.20	19,950	1,243	62.31	0	0	0.00

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide conventional fuel account balances in dollars and quantities for each fuel type for the test year and the two preceeding years. Include Natural Gas even though no Inventory is carried. (Give units in Barrels, Tons, or MCF)

Type of Data Shown:

X Projected Test Year Ended 12/31/14

Prior Year Ended 12/31/13

Historical Year Ended 12/31/12

Witness: M. L. Burroughs, S. D. Ritenour

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
				Fuel Issues (Other)			Adjustments			Ending Inventory		
Line No.	Plant	Fuel Type	Month	Units	($000)	$/Unit	Units	($000)	$/Unit	Units	($000)	$/Unit
1	Daniel	Coal (tons)	Dec-13	0	0	0.00	0	0	0.00	361,287	41,765	115.60
2	Daniel	Coal (tons)	Jan-14	0	0	0.00	0	0	0.00	322,804	37,001	114.62
3	Daniel	Coal (tons)	Feb-14	0	0	0.00	0	0	0.00	330,954	36,910	111.53
4	Daniel	Coal (tons)	Mar-14	0	0	0.00	0	0	0.00	332,329	36,107	108.65
5	Daniel	Coal (tons)	Apr-14	0	0	0.00	0	0	0.00	328,191	34,775	105.96
6	Daniel	Coal (tons)	May-14	0	0	0.00	0	0	0.00	329,002	34,021	103.41
7	Daniel	Coal (tons)	Jun-14	0	0	0.00	0	0	0.00	300,973	29,756	98.87
8	Daniel	Coal (tons)	Jul-14	0	0	0.00	0	0	0.00	253,515	23,957	94.50
9	Daniel	Coal (tons)	Aug-14	0	0	0.00	0	0	0.00	209,569	19,064	90.97
10	Daniel	Coal (tons)	Sep-14	0	0	0.00	0	0	0.00	189,512	16,612	87.66
11	Daniel	Coal (tons)	Oct-14	0	0	0.00	0	0	0.00	181,167	15,086	83.27
12	Daniel	Coal (tons)	Nov-14	0	0	0.00	0	0	0.00	193,047	15,675	81.20
13	Daniel	Coal (tons)	Dec-14	0	0	0.00	0	0	0.00	212,997	16,918	79.43
14	Total									3,545,347	357,647	
15	Daniel	Coal (tons)	13 mth avg							272,719	27,511	100.88

16 Totals may not add due to rounding.

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide conventional fuel account balances in dollars and quantities for each fuel type for the test year and the two preceeding years. Include Natural Gas even though no inventory is carried. (Give units in Barrels, Tons, or MCF)

Type of Data Shown:

X Projected Test Year Ended 12/31/14

Prior Year Ended 12/31/13

Historical Year Ended 12/31/12

Witness: M. L. Burroughs, S. D. Ritenour

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
				Beginning Inventory			Receipts			Fuel Issued to Generation		
Line No.	Plant	Fuel Type	Month	Units	($000)	$/Unit	Units	($000)	$/Unit	Units	($000)	$/Unit
1	Scherer	Coal (tons)	Dec-13	125,974	5,674	45.04	66,100	2,996	45.33	82,743	3,735	45.14
2	Scherer	Coal (tons)	Jan-14	109,331	4,935	45.14	146,232	6,122	41.86	85,983	3,720	43.26
3	Scherer	Coal (tons)	Feb-14	169,580	7,337	43.27	76,057	3,289	43.24	76,057	3,290	43.26
4	Scherer	Coal (tons)	Mar-14	169,580	7,336	43.26	78,367	3,355	42.81	78,367	3,379	43.12
5	Scherer	Coal (tons)	Apr-14	169,580	7,312	43.12	76,996	3,272	42.50	76,996	3,305	42.92
6	Scherer	Coal (tons)	May-14	169,580	7,279	42.92	79,181	3,366	42.51	79,181	3,388	42.79
7	Scherer	Coal (tons)	Jun-14	169,580	7,257	42.79	74,433	3,167	42.55	74,433	3,180	42.72
8	Scherer	Coal (tons)	Jul-14	169,580	7,244	42.72	79,189	3,365	42.49	79,189	3,377	42.64
9	Scherer	Coal (tons)	Aug-14	169,580	7,232	42.65	79,091	3,363	42.52	79,091	3,370	42.61
10	Scherer	Coal (tons)	Sep-14	169,580	7,225	42.61	33,973	1,548	45.57	76,639	3,303	43.10
11	Scherer	Coal (tons)	Oct-14	126,914	5,470	43.10	35,951	1,638	45.56	80,059	3,494	43.64
12	Scherer	Coal (tons)	Nov-14	82,806	3,614	43.64	24,892	1,152	46.28	0	0	0.00
13	Scherer	Coal (tons)	Dec-14	107,698	4,786	44.25	77,609	3,275	42.20	7,568	328	43.34

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide conventional fuel account balances in dollars and quantities for each fuel type for the test year and the two preceeding years. Include Natural Gas even though no inventory is carried. (Give units in Barrels, Tons, or MCF)

Type of Data Shown:

X Projected Test Year Ended 12/31/14

Prior Year Ended 12/31/13

Historical Year Ended 12/31/12

Witness: M. L. Burroughs, S. D. Ritenour

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
				Fuel Issues (Other)			Adjustments			Ending Inventory		
Line No.	Plant	Fuel Type	Month	Units	($000)	$/Unit	Units	($000)	$/Unit	Units	($000)	$/Unit
1	Scherer	Coal (tons)	Dec-13	0	0	0.00	0	0	0.00	109,331	4,935	45.14
2	Scherer	Coal (tons)	Jan-14	0	0	0.00	0	0	0.00	169,580	7,337	43.27
3	Scherer	Coal (tons)	Feb-14	0	0	0.00	0	0	0.00	169,580	7,336	43.26
4	Scherer	Coal (tons)	Mar-14	0	0	0.00	0	0	0.00	169,580	7,312	43.12
5	Scherer	Coal (tons)	Apr-14	0	0	0.00	0	0	0.00	169,580	7,279	42.92
6	Scherer	Coal (tons)	May-14	0	0	0.00	0	0	0.00	169,580	7,257	42.79
7	Scherer	Coal (tons)	Jun-14	0	0	0.00	0	0	0.00	169,580	7,244	42.72
8	Scherer	Coal (tons)	Jul-14	0	0	0.00	0	0	0.00	169,580	7,232	42.65
9	Scherer	Coal (tons)	Aug-14	0	0	0.00	0	0	0.00	169,580	7,225	42.61
10	Scherer	Coal (tons)	Sep-14	0	0	0.00	0	0	0.00	126,914	5,470	43.10
11	Scherer	Coal (tons)	Oct-14	0	0	0.00	0	0	0.00	82,806	3,614	43.64
12	Scherer	Coal (tons)	Nov-14	0	0	0.00	0	0	0.00	107,698	4,766	44.25
13	Scherer	Coal (tons)	Dec-14	0	0	0.00	0	0	0.00	177,739	7,713	43.40
14	Total									1,961,128	84,720	
15	Scherer	Coal (tons)	13 mth avg							150,856	6,517	43.20

16 Totals may not add due to rounding.

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide conventional fuel account balances in dollars and quantities for each fuel type for the test year and the two preceeding years. Include Natural Gas even though no inventory is carried. (Give units in Barrels, Tons, or MCF)

Type of Data Shown:

X Projected Test Year Ended 12/31/14

____ Prior Year Ended 12/31/13

____ Historical Year Ended 12/31/12

Witness: M. L. Burroughs, S. D. Ritenour

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
				Beginning Inventory			Receipts			Fuel Issued to Generation		
Line No.	Plant	Fuel Type	Month	Units	($000)	$/Unit	Units	($000)	$/Unit	Units	($000)	$/Unit
1	Cent. AL	CT Oil	Dec-13	9,283	770	82.95	0	0	0.00	0	0	0.00
2	Cent. AL	CT Oil	Jan-14	9,283	770	82.95	0	0	0.00	0	0	0.00
3	Cent. AL	CT Oil	Feb-14	9,283	770	82.95	0	0	0.00	0	0	0.00
4	Cent. AL	CT Oil	Mar-14	9,283	770	82.95	0	0	0.00	0	0	0.00
5	Cent. AL	CT Oil	Apr-14	9,283	770	82.95	0	0	0.00	0	0	0.00
6	Cent. AL	CT Oil	May-14	9,283	770	82.95	0	0	0.00	0	0	0.00
7	Cent. AL	CT Oil	Jun-14	9,283	770	82.95	0	0	0.00	0	0	0.00
8	Cent. AL	CT Oil	Jul-14	9,283	770	82.95	0	0	0.00	0	0	0.00
9	Cent. AL	CT Oil	Aug-14	9,283	770	82.95	0	0	0.00	0	0	0.00
10	Cent. AL	CT Oil	Sep-14	9,283	770	82.95	0	0	0.00	0	0	0.00
11	Cent. AL	CT Oil	Oct-14	9,283	770	82.95	0	0	0.00	0	0	0.00
12	Cent. AL	CT Oil	Nov-14	9,283	770	82.95	0	0	0.00	0	0	0.00
13	Cent. AL	CT Oil	Dec-14	9,283	770	82.95	0	0	0.00	0	0	0.00

14 Note: Gulf provides the fuel to operate these units per the Purchase Power Agreement.

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide conventional fuel account balances in dollars and quantities for each fuel type for the test year and the two preceeding years. Include Natural Gas even though no inventory is carried. (Give units in Barrels, Tons, or MCF)

Type of Data Shown:

X Projected Test Year Ended 12/31/14

____ Prior Year Ended 12/31/13

____ Historical Year Ended 12/31/12

Witness: M. L. Burroughs, S. D. Ritenour

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
				Fuel Issues (Other)			Adjustments			Ending Inventory		
Line No.	Plant	Fuel Type	Month	Units	($000)	$/Unit	Units	($000)	$/Unit	Units	($000)	$/Unit
1	Cent. AL	CT Oil	Dec-13	0	0	0.00	0	0	0.00	9,283	770	82.95
2	Cent. AL	CT Oil	Jan-14	0	0	0.00	0	0	0.00	9,283	770	82.95
3	Cent. AL	CT Oil	Feb-14	0	0	0.00	0	0	0.00	9,283	770	82.95
4	Cent. AL	CT Oil	Mar-14	0	0	0.00	0	0	0.00	9,283	770	82.95
5	Cent. AL	CT Oil	Apr-14	0	0	0.00	0	0	0.00	9,283	770	82.95
6	Cent. AL	CT Oil	May-14	0	0	0.00	0	0	0.00	9,283	770	82.95
7	Cent. AL	CT Oil	Jun-14	0	0	0.00	0	0	0.00	9,283	770	82.95
8	Cent. AL	CT Oil	Jul-14	0	0	0.00	0	0	0.00	9,283	770	82.95
9	Cent. AL	CT Oil	Aug-14	0	0	0.00	0	0	0.00	9,283	770	82.95
10	Cent. AL	CT Oil	Sep-14	0	0	0.00	0	0	0.00	9,283	770	82.95
11	Cent. AL	CT Oil	Oct-14	0	0	0.00	0	0	0.00	9,283	770	82.95
12	Cent. AL	CT Oil	Nov-14	0	0	0.00	0	0	0.00	9,283	770	82.95
13	Cent. AL	CT Oil	Dec-14	0	0	0.00	0	0	0.00	9,283	770	82.95
14	Total									120,679	10,010	
15	Cent. AL	CT Oil	13 mth avg							9,283	770	82.95

16 Note: Gulf provides the fuel to operate these units per the Purchase Power Agreement.

17 Totals may not add due to rounding.

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide conventional fuel account balances in dollars and quantities for each fuel type for the test year and the two preceeding years. Include Natural Gas even though no inventory is carried. (Give units in Barrels, Tons, or MCF)

Type of Data Shown:

X Projected Test Year Ended 12/31/14

____ Prior Year Ended 12/31/13

____ Historical Year Ended 12/31/12

Witness: M. L. Burroughs, S. D. Ritenour

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
				Beginning Inventory			Receipts			Fuel Issued to Generation		
Line No.	Plant	Fuel Type	Month	Units	($000)	$/Unit	Units	($000)	$/Unit	Units	($000)	$/Unit
1	Baconton	CT Oil	Dec-13	8,077	696	86.17	0	0	0.00	0	0	0.00
2	Baconton	CT Oil	Jan-14	8,077	696	86.17	0	0	0.00	0	0	0.00
3	Baconton	CT Oil	Feb-14	8,077	696	86.17	0	0	0.00	0	0	0.00
4	Baconton	CT Oil	Mar-14	8,077	696	86.17	0	0	0.00	0	0	0.00
5	Baconton	CT Oil	Apr-14	8,077	696	86.17	0	0	0.00	0	0	0.00
6	Baconton	CT Oil	May-14	8,077	696	86.17	0	0	0.00	0	0	0.00
7	Baconton	CT Oil	Jun-14	8,077	696	86.17	0	0	0.00	0	0	0.00
8	Baconton	CT Oil	Jul-14	0	0	0.00	0	0	0.00	0	0	0.00
9	Baconton	CT Oil	Aug-14	0	0	0.00	0	0	0.00	0	0	0.00
10	Baconton	CT Oil	Sep-14	0	0	0.00	0	0	0.00	0	0	0.00
11	Baconton	CT Oil	Oct-14	0	0	0.00	0	0	0.00	0	0	0.00
12	Baconton	CT Oil	Nov-14	0	0	0.00	0	0	0.00	0	0	0.00
13	Baconton	CT Oil	Dec-14	0	0	0.00	0	0	0.00	0	0	0.00

14 Note: Gulf provides the fuel to operate these units per the Purchase Power Agreement.

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide conventional fuel account balances in dollars and quantities for each fuel type for the test year and the two preceeding years. Include Natural Gas even though no inventory is carried. (Give units in Barrels, Tons, or MCF)

Type of Data Shown:

X Projected Test Year Ended 12/31/14

_____ Prior Year Ended 12/31/13

_____ Historical Year Ended 12/31/12

Witness: M. L. Burroughs, S. D. Ritenour

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
				Fuel Issues (Other)			Adjustments			Ending Inventory		
Line No.	Plant	Fuel Type	Month	Units	($000)	$/Unit	Units	($000)	$/Unit	Units	($000)	$/Unit
1	Baconton	CT Oil	Dec-13	0	0	0.00	0	0	0.00	8,077	696	86.17
2	Baconton	CT Oil	Jan-14	0	0	0.00	0	0	0.00	8,077	696	86.17
3	Baconton	CT Oil	Feb-14	0	0	0.00	0	0	0.00	8,077	696	86.17
4	Baconton	CT Oil	Mar-14	0	0	0.00	0	0	0.00	8,077	696	86.17
5	Baconton	CT Oil	Apr-14	0	0	0.00	0	0	0.00	8,077	696	86.17
6	Baconton	CT Oil	May-14	0	0	0.00	0	0	0.00	8,077	696	86.17
7	Baconton	CT Oil	Jun-14	8,077	696	86.17	0	0	0.00	0	0	0.00
8	Baconton	CT Oil	Jul-14	0	0	0.00	0	0	0.00	0	0	0.00
9	Baconton	CT Oil	Aug-14	0	0	0.00	0	0	0.00	0	0	0.00
10	Baconton	CT Oil	Sep-14	0	0	0.00	0	0	0.00	0	0	0.00
11	Baconton	CT Oil	Oct-14	0	0	0.00	0	0	0.00	0	0	0.00
12	Baconton	CT Oil	Nov-14	0	0	0.00	0	0	0.00	0	0	0.00
13	Baconton	CT Oil	Dec-14	0	0	0.00	0	0	0.00	0	0	0.00
14	Total									48,462	4,176	
15	Baconton	CT Oil	13 mth avg							3,728	321	86.11

16 Note: Gulf provides the fuel to operate these units per the Purchase Power Agreement.

17 Totals may not add due to rounding.

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide conventional fuel account balances in dollars and quantities for each fuel type for the test year and the two preceeding years. Include Natural Gas even though no inventory is carried. (Give units in Barrels, Tons, or MCF)

Type of Data Shown:

X Projected Test Year Ended 12/31/14

Prior Year Ended 12/31/13

Historical Year Ended 12/31/12

Witness: M. L. Burroughs, S. D. Ritenour

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
				Beginning Inventory			Receipts			Fuel Issued to Generation		
Line No.	Plant	Fuel Type	Month	Units	($000)	$/Unit	Units	($000)	$/Unit	Units	($000)	$/Unit
1	Dahlberg	CT Oil	Dec-13	10,911	982	90.00	0	0	0.00	0	0	0.00
2	Dahlberg	CT Oil	Jan-14	10,911	982	90.00	0	0	0.00	0	0	0.00
3	Dahlberg	CT Oil	Feb-14	10,911	982	90.00	0	0	0.00	0	0	0.00
4	Dahlberg	CT Oil	Mar-14	10,911	982	90.00	0	0	0.00	0	0	0.00
5	Dahlberg	CT Oil	Apr-14	10,911	982	90.00	0	0	0.00	0	0	0.00
6	Dahlberg	CT Oil	May-14	10,911	982	90.00	0	0	0.00	0	0	0.00
7	Dahlberg	CT Oil	Jun-14	10,911	982	90.00	0	0	0.00	0	0	0.00
8	Dahlberg	CT Oil	Jul-14	0	0	0.00	0	0	0.00	0	0	0.00
9	Dahlberg	CT Oil	Aug-14	0	0	0.00	0	0	0.00	0	0	0.00
10	Dahlberg	CT Oil	Sep-14	0	0	0.00	0	0	0.00	0	0	0.00
11	Dahlberg	CT Oil	Oct-14	0	0	0.00	0	0	0.00	0	0	0.00
12	Dahlberg	CT Oil	Nov-14	0	0	0.00	0	0	0.00	0	0	0.00
13	Dahlberg	CT Oil	Dec-14	0	0	0.00	0	0	0.00	0	0	0.00

14 Note: Gulf provides the fuel to operate these units per the Purchase Power Agreement.

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide conventional fuel account balances in dollars and quantities for each fuel type for the test year and the two preceeding years. Include Natural Gas even though no inventory is carried. (Give units in Barrels, Tons, or MCF)

Type of Data Shown:

X Projected Test Year Ended 12/31/14

____ Prior Year Ended 12/31/13

____ Historical Year Ended 12/31/12

Witness: M. L. Burroughs, S. D. Ritenour

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
				Fuel Issues (Other)			Adjustments			Ending Inventory		
Line No.	Plant	Fuel Type	Month	Units	($000)	$/Unit	Units	($000)	$/Unit	Units	($000)	$/Unit
1	Dahlberg	CT Oil	Dec-13	0	0	0.00	0	0	0.00	10,911	982	90.00
2	Dahlberg	CT Oil	Jan-14	0	0	0.00	0	0	0.00	10,911	982	90.00
3	Dahlberg	CT Oil	Feb-14	0	0	0.00	0	0	0.00	10,911	982	90.00
4	Dahlberg	CT Oil	Mar-14	0	0	0.00	0	0	0.00	10,911	982	90.00
5	Dahlberg	CT Oil	Apr-14	0	0	0.00	0	0	0.00	10,911	982	90.00
6	Dahlberg	CT Oil	May-14	0	0	0.00	0	0	0.00	10,911	982	90.00
7	Dahlberg	CT Oil	Jun-14	10,911	982	90.00	0	0	0.00	0	0	0.00
8	Dahlberg	CT Oil	Jul-14	0	0	0.00	0	0	0.00	0	0	0.00
9	Dahlberg	CT Oil	Aug-14	0	0	0.00	0	0	0.00	0	0	0.00
10	Dahlberg	CT Oil	Sep-14	0	0	0.00	0	0	0.00	0	0	0.00
11	Dahlberg	CT Oil	Oct-14	0	0	0.00	0	0	0.00	0	0	0.00
12	Dahlberg	CT Oil	Nov-14	0	0	0.00	0	0	0.00	0	0	0.00
13	Dahlberg	CT Oil	Dec-14	0	0	0.00	0	0	0.00	0	0	0.00
14	Total									65,466	5,892	
15	Dahlberg	CT Oil	13 mth avg							5,036	453	89.95

16 Note: Gulf provides the fuel to operate these units per the Purchase Power Agreement.

17 Totals may not add due to rounding.

Supporting Schedules:

Recap Schedules:

Schedule B-18 | FUEL INVENTORY BY PLANT | Page 17 of 114

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide conventional fuel account balances in dollars and quantities for each fuel type for the test year and the two preceeding years. Include Natural Gas even though no inventory is carried. (Give units in Barrels, Tons, or MCF)

Type of Data Shown:

X Projected Test Year Ended 12/31/14

____ Prior Year Ended 12/31/13

____ Historical Year Ended 12/31/12

Witness: M. L. Burroughs, S. D. Ritenour

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
				Beginning Inventory			Receipts			Fuel Issued to Generation		
Line No.	Plant	Fuel Type	Month	Units	($000)	$/Unit	Units	($000)	$/Unit	Units	($000)	$/Unit
1	Smith	CT Oil	Dec-13	7,143	778	108.92	0	0	0.00	0	0	0.00
2	Smith	CT Oil	Jan-14	7,143	778	108.92	0	0	0.00	0	0	0.00
3	Smith	CT Oil	Feb-14	7,143	778	108.92	0	0	0.00	0	0	0.00
4	Smith	CT Oil	Mar-14	7,143	778	108.92	0	0	0.00	0	0	0.00
5	Smith	CT Oil	Apr-14	7,143	778	108.92	0	0	0.00	0	0	0.00
6	Smith	CT Oil	May-14	7,143	778	108.92	0	0	0.00	0	0	0.00
7	Smith	CT Oil	Jun-14	7,143	778	108.92	0	0	0.00	0	0	0.00
8	Smith	CT Oil	Jul-14	7,143	778	108.92	0	0	0.00	0	0	0.00
9	Smith	CT Oil	Aug-14	7,143	778	108.92	0	0	0.00	0	0	0.00
10	Smith	CT Oil	Sep-14	7,143	778	108.92	0	0	0.00	0	0	0.00
11	Smith	CT Oil	Oct-14	7,143	778	108.92	0	0	0.00	0	0	0.00
12	Smith	CT Oil	Nov-14	7,143	778	108.92	0	0	0.00	0	0	0.00
13	Smith	CT Oil	Dec-14	7,143	778	108.92	0	0	0.00	0	0	0.00

14 Note: Gulf provides the fuel to operate these units per the Purchase Power Agreement.

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Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide conventional fuel account balances in dollars and quantities for each fuel type for the test year and the two preceeding years. Include Natural Gas even though no inventory is carried. (Give units in Barrels, Tons, or MCF)

Type of Data Shown:

X Projected Test Year Ended 12/31/14

____ Prior Year Ended 12/31/13

____ Historical Year Ended 12/31/12

Witness: M. L. Burroughs, S. D. Ritenour

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
				Fuel Issues (Other)			Adjustments			Ending Inventory		
Line No.	Plant	Fuel Type	Month	Units	($000)	$/Unit	Units	($000)	$/Unit	Units	($000)	$/Unit
1	Smith	CT Oil	Dec-13	0	0	0.00	0	0	0.00	7,143	778	108.92
2	Smith	CT Oil	Jan-14	0	0	0.00	0	0	0.00	7,143	778	108.92
3	Smith	CT Oil	Feb-14	0	0	0.00	0	0	0.00	7,143	778	108.92
4	Smith	CT Oil	Mar-14	0	0	0.00	0	0	0.00	7,143	778	108.92
5	Smith	CT Oil	Apr-14	0	0	0.00	0	0	0.00	7,143	778	108.92
6	Smith	CT Oil	May-14	0	0	0.00	0	0	0.00	7,143	778	108.92
7	Smith	CT Oil	Jun-14	0	0	0.00	0	0	0.00	7,143	778	108.92
8	Smith	CT Oil	Jul-14	0	0	0.00	0	0	0.00	7,143	778	108.92
9	Smith	CT Oil	Aug-14	0	0	0.00	0	0	0.00	7,143	778	108.92
10	Smith	CT Oil	Sep-14	0	0	0.00	0	0	0.00	7,143	778	108.92
11	Smith	CT Oil	Oct-14	0	0	0.00	0	0	0.00	7,143	778	108.92
12	Smith	CT Oil	Nov-14	0	0	0.00	0	0	0.00	7,143	778	108.92
13	Smith	CT Oil	Dec-14	0	0	0.00	0	0	0.00	7,143	778	108.92
14	Total									92,859	10,114	
15	Smith	CT Oil	13 mth avg							7,143	778	108.92

16 Note: Gulf provides the fuel to operate these units per the Purchase Power Agreement.

17 Totals may not add due to rounding.

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide conventional fuel account balances in dollars and quantities for each fuel type for the test year and the two preceeding years. Include Natural Gas even though no inventory is carried. (Give units in Barrels, Tons, or MCF)

Type of Data Shown:

X Projected Test Year Ended 12/31/14

____ Prior Year Ended 12/31/13

____ Historical Year Ended 12/31/12

Witness: M. L. Burroughs, S. D. Ritenour

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
				Beginning Inventory			Receipts			Fuel Issued to Generation		
Line No.	Plant	Fuel Type	Month	Units	($000)	$/Unit	Units	($000)	$/Unit	Units	($000)	$/Unit
1	Crist	Oil	Dec-13	4,286	534	124.59	182	23	126.37	182	22	120.88
2	Crist	Oil	Jan-14	4,286	535	124.83	182	22	120.88	182	22	120.88
3	Crist	Oil	Feb-14	4,286	535	124.83	182	22	120.88	182	22	120.88
4	Crist	Oil	Mar-14	4,286	535	124.83	57	6	105.26	57	7	122.81
5	Crist	Oil	Apr-14	4,286	534	124.59	154	19	123.38	154	19	123.38
6	Crist	Oil	May-14	4,286	534	124.59	182	22	120.88	182	22	120.88
7	Crist	Oil	Jun-14	4,286	534	124.59	154	19	123.38	154	19	123.38
8	Crist	Oil	Jul-14	4,286	534	124.59	182	22	120.88	182	22	120.88
9	Crist	Oil	Aug-14	4,286	534	124.59	182	22	120.88	182	22	120.88
10	Crist	Oil	Sep-14	4,286	534	124.59	154	19	123.38	154	19	123.38
11	Crist	Oil	Oct-14	4,286	534	124.59	182	22	120.88	182	22	120.88
12	Crist	Oil	Nov-14	4,286	534	124.59	182	22	120.88	182	22	120.88
13	Crist	Oil	Dec-14	4,286	534	124.59	154	19	123.38	154	19	123.38

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide conventional fuel account balances in dollars and quantities for each fuel type for the test year and the two preceeding years. Include Natural Gas even though no inventory is carried. (Give units in Barrels, Tons, or MCF)

Type of Data Shown:

X Projected Test Year Ended 12/31/14

_____ Prior Year Ended 12/31/13

_____ Historical Year Ended 12/31/12

Witness: M. L. Burroughs, S. D. Ritenour

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
				Fuel Issues (Other)			Adjustments			Ending Inventory		
Line No.	Plant	Fuel Type	Month	Units	($000)	$/Unit	Units	($000)	$/Unit	Units	($000)	$/Unit
1	Crist	Oil	Dec-13	0	0	0.00	0	0	0.00	4,286	535	124.83
2	Crist	Oil	Jan-14	0	0	0.00	0	0	0.00	4,286	535	124.83
3	Crist	Oil	Feb-14	0	0	0.00	0	0	0.00	4,286	535	124.83
4	Crist	Oil	Mar-14	0	0	0.00	0	0	0.00	4,286	534	124.59
5	Crist	Oil	Apr-14	0	0	0.00	0	0	0.00	4,286	534	124.59
6	Crist	Oil	May-14	0	0	0.00	0	0	0.00	4,286	534	124.59
7	Crist	Oil	Jun-14	0	0	0.00	0	0	0.00	4,286	534	124.59
8	Crist	Oil	Jul-14	0	0	0.00	0	0	0.00	4,286	534	124.59
9	Crist	Oil	Aug-14	0	0	0.00	0	0	0.00	4,286	534	124.59
10	Crist	Oil	Sep-14	0	0	0.00	0	0	0.00	4,286	534	124.59
11	Crist	Oil	Oct-14	0	0	0.00	0	0	0.00	4,286	534	124.59
12	Crist	Oil	Nov-14	0	0	0.00	0	0	0.00	4,286	534	124.59
13	Crist	Oil	Dec-14	0	0	0.00	0	0	0.00	4,286	534	124.59
14	Total									55,718	6,945	
15	Crist	Oil	13 mth avg							4,286	534	124.59

16 Totals may not add due to rounding.

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide conventional fuel account balances in dollars and quantities for each fuel type for the test year and the two preceeding years. Include Natural Gas even though no inventory is carried. (Give units in Barrels, Tons, or MCF)

Type of Data Shown:

X Projected Test Year Ended 12/31/14

____ Prior Year Ended 12/31/13

____ Historical Year Ended 12/31/12

Witness: M. L. Burroughs, S. D. Ritenour

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
				Beginning Inventory			Receipts			Fuel Issued to Generation		
Line No.	Plant	Fuel Type	Month	Units	($000)	$/Unit	Units	($000)	$/Unit	Units	($000)	$/Unit
1	Smith	Oil	Dec-13	476	61	128.15	399	51	127.82	399	51	127.82
2	Smith	Oil	Jan-14	476	61	128.15	399	49	122.81	399	50	125.31
3	Smith	Oil	Feb-14	476	60	126.05	399	50	125.31	399	50	125.31
4	Smith	Oil	Mar-14	476	60	126.05	399	49	122.81	399	50	125.31
5	Smith	Oil	Apr-14	476	59	123.95	399	50	125.31	399	50	125.31
6	Smith	Oil	May-14	476	59	123.95	399	50	125.31	399	50	125.31
7	Smith	Oil	Jun-14	476	59	123.95	399	50	125.31	399	50	125.31
8	Smith	Oil	Jul-14	476	59	123.95	399	50	125.31	399	50	125.31
9	Smith	Oil	Aug-14	476	59	123.95	399	50	125.31	399	50	125.31
10	Smith	Oil	Sep-14	476	59	123.95	399	50	125.31	399	50	125.31
11	Smith	Oil	Oct-14	476	59	123.95	399	50	125.31	399	50	125.31
12	Smith	Oil	Nov-14	476	59	123.95	399	50	125.31	399	50	125.31
13	Smith	Oil	Dec-14	476	59	123.95	399	50	125.31	399	50	125.31

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide conventional fuel account balances in dollars and quantities for each fuel type for the test year and the two preceeding years. Include Natural Gas even though no inventory is carried. (Give units in Barrels, Tons, or MCF)

Type of Data Shown:

X Projected Test Year Ended 12/31/14

____ Prior Year Ended 12/31/13

____ Historical Year Ended 12/31/12

Witness: M. L. Burroughs, S. D. Ritenour

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
				Fuel Issues (Other)			Adjustments			Ending Inventory		
Line No.	Plant	Fuel Type	Month	Units	($000)	$/Unit	Units	($000)	$/Unit	Units	($000)	$/Unit
1	Smith	Oil	Dec-13	0	0	0.00	0	0	0.00	476	61	128.15
2	Smith	Oil	Jan-14	0	0	0.00	0	0	0.00	476	60	126.05
3	Smith	Oil	Feb-14	0	0	0.00	0	0	0.00	476	60	126.05
4	Smith	Oil	Mar-14	0	0	0.00	0	0	0.00	476	59	123.95
5	Smith	Oil	Apr-14	0	0	0.00	0	0	0.00	476	59	123.95
6	Smith	Oil	May-14	0	0	0.00	0	0	0.00	476	59	123.95
7	Smith	Oil	Jun-14	0	0	0.00	0	0	0.00	476	59	123.95
8	Smith	Oil	Jul-14	0	0	0.00	0	0	0.00	476	59	123.95
9	Smith	Oil	Aug-14	0	0	0.00	0	0	0.00	476	59	123.95
10	Smith	Oil	Sep-14	0	0	0.00	0	0	0.00	476	59	123.95
11	Smith	Oil	Oct-14	0	0	0.00	0	0	0.00	476	59	123.95
12	Smith	Oil	Nov-14	0	0	0.00	0	0	0.00	476	59	123.95
13	Smith	Oil	Dec-14	0	0	0.00	0	0	0.00	476	59	123.95
14	Total									6,188	771	
15	Smith	Oil	13 mth avg							476	59	123.95

16 Totals may not add due to rounding.

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide conventional fuel account balances in dollars and quantities for each fuel type for the test year and the two preceeding years. Include Natural Gas even though no inventory is carried. (Give units in Barrels, Tons, or MCF)

Type of Data Shown:

X Projected Test Year Ended 12/31/14

____ Prior Year Ended 12/31/13

____ Historical Year Ended 12/31/12

Witness: M. L. Burroughs, S. D. Ritenour

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
				Beginning Inventory			Receipts			Fuel Issued to Generation		
Line No.	Plant	Fuel Type	Month	Units	($000)	$/Unit	Units	($000)	$/Unit	Units	($000)	$/Unit
1	Scholz	Oil	Dec-13	357	46	128.85	2	0	0.00	2	0	0.00
2	Scholz	Oil	Jan-14	357	46	128.85	4	0	0.00	4	0	0.00
3	Scholz	Oil	Feb-14	357	46	128.85	4	0	0.00	4	0	0.00
4	Scholz	Oil	Mar-14	357	46	128.85	4	0	0.00	4	0	0.00
5	Scholz	Oil	Apr-14	357	46	128.85	0	0	0.00	0	0	0.00
6	Scholz	Oil	May-14	357	46	128.85	0	0	0.00	0	0	0.00
7	Scholz	Oil	Jun-14	357	46	128.85	0	0	0.00	0	0	0.00
8	Scholz	Oil	Jul-14	357	46	128.85	0	0	0.00	0	0	0.00
9	Scholz	Oil	Aug-14	357	46	128.85	4	0	0.00	4	0	0.00
10	Scholz	Oil	Sep-14	357	46	128.85	4	0	0.00	4	0	0.00
11	Scholz	Oil	Oct-14	357	46	128.85	0	0	0.00	0	0	0.00
12	Scholz	Oil	Nov-14	357	46	128.85	2	0	0.00	2	0	0.00
13	Scholz	Oil	Dec-14	357	46	128.85	4	0	0.00	4	0	0.00

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide conventional fuel account balances in dollars and quantities for each fuel type for the test year and the two preceeding years. Include Natural Gas even though no inventory is carried. (Give units in Barrels, Tons, or MCF)

Type of Data Shown:

X Projected Test Year Ended 12/31/14

_____ Prior Year Ended 12/31/13

_____ Historical Year Ended 12/31/12

Witness: M. L. Burroughs, S. D. Ritenour

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
				Fuel Issues (Other)			Adjustments			Ending Inventory		
Line No.	Plant	Fuel Type	Month	Units	($000)	$/Unit	Units	($000)	$/Unit	Units	($000)	$/Unit
1	Scholz	Oil	Dec-13	0	0	0.00	0	0	0.00	357	46	128.85
2	Scholz	Oil	Jan-14	0	0	0.00	0	0	0.00	357	46	128.85
3	Scholz	Oil	Feb-14	0	0	0.00	0	0	0.00	357	46	128.85
4	Scholz	Oil	Mar-14	0	0	0.00	0	0	0.00	357	46	128.85
5	Scholz	Oil	Apr-14	0	0	0.00	0	0	0.00	357	46	128.85
6	Scholz	Oil	May-14	0	0	0.00	0	0	0.00	357	46	128.85
7	Scholz	Oil	Jun-14	0	0	0.00	0	0	0.00	357	46	128.85
8	Scholz	Oil	Jul-14	0	0	0.00	0	0	0.00	357	46	128.85
9	Scholz	Oil	Aug-14	0	0	0.00	0	0	0.00	357	46	128.85
10	Scholz	Oil	Sep-14	0	0	0.00	0	0	0.00	357	46	128.85
11	Scholz	Oil	Oct-14	0	0	0.00	0	0	0.00	357	46	128.85
12	Scholz	Oil	Nov-14	0	0	0.00	0	0	0.00	357	46	128.85
13	Scholz	Oil	Dec-14	0	0	0.00	0	0	0.00	357	46	128.85
14	Total									4,641	598	
15	Scholz	Oil	13 mth avg							357	46	128.85

16 Totals may not add due to rounding.

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide conventional fuel account balances in dollars and quantities for each fuel type for the test year and the two preceeding years. Include Natural Gas even though no inventory is carried. (Give units in Barrels, Tons, or MCF)

Type of Data Shown:

X Projected Test Year Ended 12/31/14

_____ Prior Year Ended 12/31/13

_____ Historical Year Ended 12/31/12

Witness: M. L. Burroughs, S. D. Ritenour

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
				Beginning Inventory			Receipts			Fuel Issued to Generation		
Line No.	Plant	Fuel Type	Month	Units	($000)	$/Unit	Units	($000)	$/Unit	Units	($000)	$/Unit
1	Daniel	Oil	Dec-13	2,404	323	134.36	276	35	126.81	276	37	134.06
2	Daniel	Oil	Jan-14	2,404	321	133.53	511	63	123.29	511	67	131.12
3	Daniel	Oil	Feb-14	2,404	317	131.86	276	34	123.19	276	36	130.43
4	Daniel	Oil	Mar-14	2,404	315	131.03	511	64	125.24	511	67	131.12
5	Daniel	Oil	Apr-14	2,404	312	129.78	235	29	123.40	235	30	127.66
6	Daniel	Oil	May-14	2,404	311	129.37	511	63	123.29	511	65	127.20
7	Daniel	Oil	Jun-14	2,404	309	128.54	511	63	123.29	511	65	127.20
8	Daniel	Oil	Jul-14	2,404	307	127.70	511	63	123.29	511	65	127.20
9	Daniel	Oil	Aug-14	2,404	305	126.87	511	64	125.24	511	65	127.20
10	Daniel	Oil	Sep-14	2,404	304	126.46	511	64	125.24	511	65	127.20
11	Daniel	Oil	Oct-14	2,404	303	126.04	511	64	125.24	511	65	127.20
12	Daniel	Oil	Nov-14	2,404	302	125.62	276	35	126.81	276	35	126.81
13	Daniel	Oil	Dec-14	2,404	302	125.62	0	0	0.00	0	0	0.00

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide conventional fuel account balances in dollars and quantities for each fuel type for the test year and the two preceeding years. Include Natural Gas even though no inventory is carried. (Give units in Barrels, Tons, or MCF)

Type of Data Shown:

X Projected Test Year Ended 12/31/14

____ Prior Year Ended 12/31/13

____ Historical Year Ended 12/31/12

Witness: M. L. Burroughs, S. D. Ritenour

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
				Fuel Issues (Other)			Adjustments			Ending Inventory		
Line No.	Plant	Fuel Type	Month	Units	($000)	$/Unit	Units	($000)	$/Unit	Units	($000)	$/Unit
1	Daniel	Oil	Dec-13	0	0	0.00	0	0	0.00	2,404	321	133.53
2	Daniel	Oil	Jan-14	0	0	0.00	0	0	0.00	2,404	317	131.86
3	Daniel	Oil	Feb-14	0	0	0.00	0	0	0.00	2,404	315	131.03
4	Daniel	Oil	Mar-14	0	0	0.00	0	0	0.00	2,404	312	129.78
5	Daniel	Oil	Apr-14	0	0	0.00	0	0	0.00	2,404	311	129.37
6	Daniel	Oil	May-14	0	0	0.00	0	0	0.00	2,404	309	128.54
7	Daniel	Oil	Jun-14	0	0	0.00	0	0	0.00	2,404	307	127.70
8	Daniel	Oil	Jul-14	0	0	0.00	0	0	0.00	2,404	305	126.87
9	Daniel	Oil	Aug-14	0	0	0.00	0	0	0.00	2,404	304	126.46
10	Daniel	Oil	Sep-14	0	0	0.00	0	0	0.00	2,404	303	126.04
11	Daniel	Oil	Oct-14	0	0	0.00	0	0	0.00	2,404	302	125.62
12	Daniel	Oil	Nov-14	0	0	0.00	0	0	0.00	2,404	302	125.62
13	Daniel	Oil	Dec-14	0	0	0.00	0	0	0.00	2,404	302	125.62
14	Total									31,252	4,010	
15	Daniel	Oil	13 mth avg							2,404	308	128.12

16 Totals may not add due to rounding.

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide conventional fuel account balances in dollars and quantities for each fuel type for the test year and the two preceeding years. Include Natural Gas even though no inventory is carried. (Give units in Barrels, Tons, or MCF)

Type of Data Shown:

X Projected Test Year Ended 12/31/14

____ Prior Year Ended 12/31/13

____ Historical Year Ended 12/31/12

Witness: M. L. Burroughs, S. D. Ritenour

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
				Beginning Inventory			Receipts			Fuel Issued to Generation		
Line No.	Plant	Fuel Type	Month	Units	($000)	$/Unit	Units	($000)	$/Unit	Units	($000)	$/Unit
1	Scherer	Oil	Dec-13	845	117	138.46	141	19	134.75	141	19	134.75
2	Scherer	Oil	Jan-14	845	117	138.46	141	18	127.66	141	19	134.75
3	Scherer	Oil	Feb-14	845	116	137.28	141	18	127.66	141	19	134.75
4	Scherer	Oil	Mar-14	845	115	136.09	141	19	134.75	141	19	134.75
5	Scherer	Oil	Apr-14	845	115	136.09	141	18	127.66	141	19	134.75
6	Scherer	Oil	May-14	845	114	134.91	141	19	134.75	141	19	134.75
7	Scherer	Oil	Jun-14	845	114	134.91	141	18	127.66	141	19	134.75
8	Scherer	Oil	Jul-14	845	113	133.73	141	19	134.75	141	19	134.75
9	Scherer	Oil	Aug-14	845	113	133.73	141	19	134.75	141	19	134.75
10	Scherer	Oil	Sep-14	845	113	133.73	141	18	127.66	141	19	134.75
11	Scherer	Oil	Oct-14	845	112	132.54	141	19	134.75	141	19	134.75
12	Scherer	Oil	Nov-14	845	112	132.54	0	0	0.00	0	0	0.00
13	Scherer	Oil	Dec-14	845	112	132.54	141	19	134.75	141	19	134.75

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide conventional fuel account balances in dollars and quantities for each fuel type for the test year and the two preceeding years. Include Natural Gas even though no inventory is carried. (Give units in Barrels, Tons, or MCF)

Type of Data Shown:

X Projected Test Year Ended 12/31/14

____ Prior Year Ended 12/31/13

____ Historical Year Ended 12/31/12

Witness: M. L. Burroughs, S. D. Ritenour

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
				Fuel Issues (Other)			Adjustments			Ending Inventory		
Line No.	Plant	Fuel Type	Month	Units	($000)	$/Unit	Units	($000)	$/Unit	Units	($000)	$/Unit
1	Scherer	Oil	Dec-13	0	0	0.00	0	0	0.00	845	117	138.46
2	Scherer	Oil	Jan-14	0	0	0.00	0	0	0.00	845	116	137.28
3	Scherer	Oil	Feb-14	0	0	0.00	0	0	0.00	845	115	136.09
4	Scherer	Oil	Mar-14	0	0	0.00	0	0	0.00	845	115	136.09
5	Scherer	Oil	Apr-14	0	0	0.00	0	0	0.00	845	114	134.91
6	Scherer	Oil	May-14	0	0	0.00	0	0	0.00	845	114	134.91
7	Scherer	Oil	Jun-14	0	0	0.00	0	0	0.00	845	113	133.73
8	Scherer	Oil	Jul-14	0	0	0.00	0	0	0.00	845	113	133.73
9	Scherer	Oil	Aug-14	0	0	0.00	0	0	0.00	845	113	133.73
10	Scherer	Oil	Sep-14	0	0	0.00	0	0	0.00	845	112	132.54
11	Scherer	Oil	Oct-14	0	0	0.00	0	0	0.00	845	112	132.54
12	Scherer	Oil	Nov-14	0	0	0.00	0	0	0.00	845	112	132.54
13	Scherer	Oil	Dec-14	0	0	0.00	0	0	0.00	845	112	132.54
14	Total									10,985	1,478	
15	Scherer	Oil	13 mth avg							845	114	134.91

16 Totals may not add due to rounding.

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide conventional fuel account balances in dollars and quantities for each fuel type for the test year and the two preceeding years. Include Natural Gas even though no inventory is carried. (Give units in Barrels, Tons, or MCF)

Type of Data Shown:

X Projected Test Year Ended 12/31/14

____ Prior Year Ended 12/31/13

____ Historical Year Ended 12/31/12

Witness: M. L. Burroughs, S. D. Ritenour

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
				Beginning Inventory			Receipts			Fuel Issued to Generation		
Line No.	Plant	Fuel Type	Month	Units	($000)	$/Unit	Units	($000)	$/Unit	Units	($000)	$/Unit
1	Smith	Nat. Gas	Dec-13	886,893	3,802	4.29	1,603,134	8,437	5.26	1,761,508	8,972	5.09
2	Smith	Nat. Gas	Jan-14	728,519	3,267	4.48	1,761,716	9,254	5.25	1,761,716	9,178	5.21
3	Smith	Nat. Gas	Feb-14	728,519	3,343	4.59	2,172,881	11,079	5.10	2,172,881	11,087	5.10
4	Smith	Nat. Gas	Mar-14	728,519	3,335	4.58	2,312,283	11,385	4.92	2,312,283	11,446	4.95
5	Smith	Nat. Gas	Apr-14	728,519	3,274	4.49	2,307,631	12,182	5.28	2,370,980	12,591	5.31
6	Smith	Nat. Gas	May-14	665,170	2,865	4.31	2,544,806	13,411	5.27	2,513,131	13,267	5.28
7	Smith	Nat. Gas	Jun-14	696,845	3,009	4.32	2,578,974	13,705	5.31	2,325,576	12,591	5.41
8	Smith	Nat. Gas	Jul-14	950,243	4,123	4.34	2,455,849	13,331	5.43	2,455,849	13,302	5.42
9	Smith	Nat. Gas	Aug-14	950,243	4,152	4.37	2,429,890	13,257	5.46	2,429,890	13,237	5.45
10	Smith	Nat. Gas	Sep-14	950,243	4,172	4.39	2,288,604	12,552	5.48	2,320,279	12,691	5.47
11	Smith	Nat. Gas	Oct-14	918,568	4,033	4.39	2,349,593	12,838	5.46	2,381,268	12,940	5.43
12	Smith	Nat. Gas	Nov-14	886,893	3,931	4.43	2,238,221	11,263	5.03	2,238,221	11,180	5.00
13	Smith	Nat. Gas	Dec-14	886,893	4,014	4.53	1,510,377	8,356	5.53	1,668,751	8,936	5.35

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide conventional fuel account balances in dollars and quantities for each fuel type for the test year and the two preceeding years. Include Natural Gas even though no inventory is carried. (Give units in Barrels, Tons, or MCF)

Type of Data Shown:

X Projected Test Year Ended 12/31/14

____ Prior Year Ended 12/31/13

____ Historical Year Ended 12/31/12

Witness: M. L. Burroughs, S. D. Ritenour

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
				Fuel Issues (Other)			Adjustments			Ending Inventory		
Line No.	Plant	Fuel Type	Month	Units	($000)	$/Unit	Units	($000)	$/Unit	Units	($000)	$/Unit
1	Smith	Nat. Gas	Dec-13	0	0	0.00	0	0	0.00	728,519	3,267	4.48
2	Smith	Nat. Gas	Jan-14	0	0	0.00	0	0	0.00	728,519	3,343	4.59
3	Smith	Nat. Gas	Feb-14	0	0	0.00	0	0	0.00	728,519	3,335	4.58
4	Smith	Nat. Gas	Mar-14	0	0	0.00	0	0	0.00	728,519	3,274	4.49
5	Smith	Nat. Gas	Apr-14	0	0	0.00	0	0	0.00	665,170	2,865	4.31
6	Smith	Nat. Gas	May-14	0	0	0.00	0	0	0.00	696,845	3,009	4.32
7	Smith	Nat. Gas	Jun-14	0	0	0.00	0	0	0.00	950,243	4,123	4.34
8	Smith	Nat. Gas	Jul-14	0	0	0.00	0	0	0.00	950,243	4,152	4.37
9	Smith	Nat. Gas	Aug-14	0	0	0.00	0	0	0.00	950,243	4,172	4.39
10	Smith	Nat. Gas	Sep-14	0	0	0.00	0	0	0.00	918,568	4,033	4.39
11	Smith	Nat. Gas	Oct-14	0	0	0.00	0	0	0.00	886,893	3,931	4.43
12	Smith	Nat. Gas	Nov-14	0	0	0.00	0	0	0.00	886,893	4,014	4.53
13	Smith	Nat. Gas	Dec-14	0	0	0.00	0	0	0.00	728,519	3,434	4.71
14	Total									10,547,693	46,952	
15	Smith	Nat. Gas	13 mth avg							811,361	3,612	4.45

16 Totals may not add due to rounding.

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide conventional fuel account balances in dollars and quantities for each fuel type for the test year and the two preceeding years. Include Natural Gas even though no inventory is carried. (Give units in Barrels, Tons, or MCF)

Type of Data Shown:

X Projected Test Year Ended 12/31/14

____ Prior Year Ended 12/31/13

____ Historical Year Ended 12/31/12

Witness: M. L. Burroughs, S. D. Ritenour

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
				Beginning Inventory			Receipts			Fuel Issued to Generation		
Line No.	Plant	Fuel Type	Month	Units	($000)	$/Unit	Units	($000)	$/Unit	Units	($000)	$/Unit
1	Crist	Nat. Gas	Dec-13	0	0	0.00	38,836	286	7.36	38,836	286	7.36
2	Crist	Nat. Gas	Jan-14	0	0	0.00	38,836	290	7.47	38,836	290	7.47
3	Crist	Nat. Gas	Feb-14	0	0	0.00	29,127	246	8.45	29,127	246	8.45
4	Crist	Nat. Gas	Mar-14	0	0	0.00	19,418	200	10.30	19,418	200	10.30
5	Crist	Nat. Gas	Apr-14	0	0	0.00	29,127	237	8.14	29,127	237	8.14
6	Crist	Nat. Gas	May-14	0	0	0.00	38,836	278	7.16	38,836	278	7.16
7	Crist	Nat. Gas	Jun-14	0	0	0.00	29,127	238	8.17	29,127	238	8.17
8	Crist	Nat. Gas	Jul-14	0	0	0.00	38,836	282	7.26	38,836	282	7.26
9	Crist	Nat. Gas	Aug-14	0	0	0.00	38,836	282	7.26	38,836	282	7.26
10	Crist	Nat. Gas	Sep-14	0	0	0.00	29,127	240	8.24	29,127	240	8.24
11	Crist	Nat. Gas	Oct-14	0	0	0.00	38,836	282	7.26	38,836	282	7.26
12	Crist	Nat. Gas	Nov-14	0	0	0.00	38,836	286	7.36	38,836	286	7.36
13	Crist	Nat. Gas	Dec-14	0	0	0.00	29,127	249	8.55	29,127	249	8.55

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide conventional fuel account balances in dollars and quantities for each fuel type for the test year and the two preceeding years. Include Natural Gas even though no inventory is carried. (Give units in Barrels, Tons, or MCF)

Type of Data Shown:

X Projected Test Year Ended 12/31/14

____ Prior Year Ended 12/31/13

____ Historical Year Ended 12/31/12

Witness: M. L. Burroughs, S. D. Ritenour

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
				Fuel Issues (Other)			Adjustments			Ending Inventory		
Line No.	Plant	Fuel Type	Month	Units	($000)	$/Unit	Units	($000)	$/Unit	Units	($000)	$/Unit
1	Crist	Nat. Gas	Dec-13	0	0	0.00	0	0	0.00	0	0	0.00
2	Crist	Nat. Gas	Jan-14	0	0	0.00	0	0	0.00	0	0	0.00
3	Crist	Nat. Gas	Feb-14	0	0	0.00	0	0	0.00	0	0	0.00
4	Crist	Nat. Gas	Mar-14	0	0	0.00	0	0	0.00	0	0	0.00
5	Crist	Nat. Gas	Apr-14	0	0	0.00	0	0	0.00	0	0	0.00
6	Crist	Nat. Gas	May-14	0	0	0.00	0	0	0.00	0	0	0.00
7	Crist	Nat. Gas	Jun-14	0	0	0.00	0	0	0.00	0	0	0.00
8	Crist	Nat. Gas	Jul-14	0	0	0.00	0	0	0.00	0	0	0.00
9	Crist	Nat. Gas	Aug-14	0	0	0.00	0	0	0.00	0	0	0.00
10	Crist	Nat. Gas	Sep-14	0	0	0.00	0	0	0.00	0	0	0.00
11	Crist	Nat. Gas	Oct-14	0	0	0.00	0	0	0.00	0	0	0.00
12	Crist	Nat. Gas	Nov-14	0	0	0.00	0	0	0.00	0	0	0.00
13	Crist	Nat. Gas	Dec-14	0	0	0.00	0	0	0.00	0	0	0.00
14	Total									0	0	
15	Crist	Nat. Gas	13 mth avg							0	0	0.00

16 Totals may not add due to rounding.

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide conventional fuel account balances in dollars and quantities for each fuel type for the test year and the two preceeding years. Include Natural Gas even though no inventory is carried. (Give units in Barrels, Tons, or MCF)

Type of Data Shown:

X Projected Test Year Ended 12/31/14

____ Prior Year Ended 12/31/13

____ Historical Year Ended 12/31/12

Witness: M. L. Burroughs, S. D. Ritenour

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
				Beginning Inventory			Receipts			Fuel Issued to Generation		
Line No.	Plant	Fuel Type	Month	Units	($000)	$/Unit	Units	($000)	$/Unit	Units	($000)	$/Unit
1	Baconton	Nat. Gas	Dec-13	0	0	0.00	0	0	0.00	0	0	0.00
2	Baconton	Nat. Gas	Jan-14	0	0	0.00	3,802	20	5.26	3,802	20	5.26
3	Baconton	Nat. Gas	Feb-14	0	0	0.00	0	0	0.00	0	0	0.00
4	Baconton	Nat. Gas	Mar-14	0	0	0.00	4,596	24	5.22	4,596	24	5.22
5	Baconton	Nat. Gas	Apr-14	0	0	0.00	0	0	0.00	0	0	0.00
6	Baconton	Nat. Gas	May-14	0	0	0.00	232,943	1,231	5.28	232,943	1,231	5.28
7	Baconton	Nat. Gas	Jun-14	0	0	0.00	0	0	0.00	0	0	0.00
8	Baconton	Nat. Gas	Jul-14	0	0	0.00	0	0	0.00	0	0	0.00
9	Baconton	Nat. Gas	Aug-14	0	0	0.00	0	0	0.00	0	0	0.00
10	Baconton	Nat. Gas	Sep-14	0	0	0.00	0	0	0.00	0	0	0.00
11	Baconton	Nat. Gas	Oct-14	0	0	0.00	0	0	0.00	0	0	0.00
12	Baconton	Nat. Gas	Nov-14	0	0	0.00	0	0	0.00	0	0	0.00
13	Baconton	Nat. Gas	Dec-14	0	0	0.00	0	0	0.00	0	0	0.00

14 Note: Gulf provides the fuel to operate these units per the Purchase Power Agreement.

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide conventional fuel account balances in dollars and quantities for each fuel type for the test year and the two preceeding years. Include Natural Gas even though no inventory is carried. (Give units in Barrels, Tons, or MCF)

Type of Data Shown:

X Projected Test Year Ended 12/31/14

____ Prior Year Ended 12/31/13

____ Historical Year Ended 12/31/12

Witness: M. L. Burroughs, S. D. Ritenour

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
				Fuel Issues (Other)			Adjustments			Ending Inventory		
Line No.	Plant	Fuel Type	Month	Units	($000)	$/Unit	Units	($000)	$/Unit	Units	($000)	$/Unit
1	Baconton	Nat. Gas	Dec-13	0	0	0.00	0	0	0.00	0	0	0.00
2	Baconton	Nat. Gas	Jan-14	0	0	0.00	0	0	0.00	0	0	0.00
3	Baconton	Nat. Gas	Feb-14	0	0	0.00	0	0	0.00	0	0	0.00
4	Baconton	Nat. Gas	Mar-14	0	0	0.00	0	0	0.00	0	0	0.00
5	Baconton	Nat. Gas	Apr-14	0	0	0.00	0	0	0.00	0	0	0.00
6	Baconton	Nat. Gas	May-14	0	0	0.00	0	0	0.00	0	0	0.00
7	Baconton	Nat. Gas	Jun-14	0	0	0.00	0	0	0.00	0	0	0.00
8	Baconton	Nat. Gas	Jul-14	0	0	0.00	0	0	0.00	0	0	0.00
9	Baconton	Nat. Gas	Aug-14	0	0	0.00	0	0	0.00	0	0	0.00
10	Baconton	Nat. Gas	Sep-14	0	0	0.00	0	0	0.00	0	0	0.00
11	Baconton	Nat. Gas	Oct-14	0	0	0.00	0	0	0.00	0	0	0.00
12	Baconton	Nat. Gas	Nov-14	0	0	0.00	0	0	0.00	0	0	0.00
13	Baconton	Nat. Gas	Dec-14	0	0	0.00	0	0	0.00	0	0	0.00
14	Total									0	0	
15	Baconton	Nat. Gas	13 mth avg							0	0	0.00

16 Note: Gulf provides the fuel to operate these units per the Purchase Power Agreement.

17 Totals may not add due to rounding.

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide conventional fuel account balances in dollars and quantities for each fuel type for the test year and the two preceeding years. Include Natural Gas even though no inventory is carried. (Give units in Barrels, Tons, or MCF)

Type of Data Shown:

X Projected Test Year Ended 12/31/14

____ Prior Year Ended 12/31/13

____ Historical Year Ended 12/31/12

Witness: M. L. Burroughs, S. D. Ritenour

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
				Beginning Inventory			Receipts			Fuel Issued to Generation		
Line No.	Plant	Fuel Type	Month	Units	($000)	$/Unit	Units	($000)	$/Unit	Units	($000)	$/Unit
1	Dahlberg	Nat. Gas	Dec-13	0	0	0.00	0	0	0.00	0	0	0.00
2	Dahlberg	Nat. Gas	Jan-14	0	0	0.00	0	0	0.00	0	0	0.00
3	Dahlberg	Nat. Gas	Feb-14	0	0	0.00	0	0	0.00	0	0	0.00
4	Dahlberg	Nat. Gas	Mar-14	0	0	0.00	0	0	0.00	0	0	0.00
5	Dahlberg	Nat. Gas	Apr-14	0	0	0.00	0	0	0.00	0	0	0.00
6	Dahlberg	Nat. Gas	May-14	0	0	0.00	19,266	182	9.45	19,266	182	9.45
7	Dahlberg	Nat. Gas	Jun-14	0	0	0.00	0	0	0.00	0	0	0.00
8	Dahlberg	Nat. Gas	Jul-14	0	0	0.00	0	0	0.00	0	0	0.00
9	Dahlberg	Nat. Gas	Aug-14	0	0	0.00	0	0	0.00	0	0	0.00
10	Dahlberg	Nat. Gas	Sep-14	0	0	0.00	0	0	0.00	0	0	0.00
11	Dahlberg	Nat. Gas	Oct-14	0	0	0.00	0	0	0.00	0	0	0.00
12	Dahlberg	Nat. Gas	Nov-14	0	0	0.00	0	0	0.00	0	0	0.00
13	Dahlberg	Nat. Gas	Dec-14	0	0	0.00	0	0	0.00	0	0	0.00

14 Note: Gulf provides the fuel to operate these units per the Purchase Power Agreement.

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide conventional fuel account balances in dollars and quantities for each fuel type for the test year and the two preceeding years. Include Natural Gas even though no inventory is carried. (Give units in Barrels, Tons, or MCF)

Type of Data Shown:

X Projected Test Year Ended 12/31/14

Prior Year Ended 12/31/13

Historical Year Ended 12/31/12

Witness: M. L. Burroughs, S. D. Ritenour

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
				Fuel Issues (Other)			Adjustments			Ending Inventory		
Line No.	Plant	Fuel Type	Month	Units	($000)	$/Unit	Units	($000)	$/Unit	Units	($000)	$/Unit
1	Dahlberg	Nat. Gas	Dec-13	0	0	0.00	0	0	0.00	0	0	0.00
2	Dahlberg	Nat. Gas	Jan-14	0	0	0.00	0	0	0.00	0	0	0.00
3	Dahlberg	Nat. Gas	Feb-14	0	0	0.00	0	0	0.00	0	0	0.00
4	Dahlberg	Nat. Gas	Mar-14	0	0	0.00	0	0	0.00	0	0	0.00
5	Dahlberg	Nat. Gas	Apr-14	0	0	0.00	0	0	0.00	0	0	0.00
6	Dahlberg	Nat. Gas	May-14	0	0	0.00	0	0	0.00	0	0	0.00
7	Dahlberg	Nat. Gas	Jun-14	0	0	0.00	0	0	0.00	0	0	0.00
8	Dahlberg	Nat. Gas	Jul-14	0	0	0.00	0	0	0.00	0	0	0.00
9	Dahlberg	Nat. Gas	Aug-14	0	0	0.00	0	0	0.00	0	0	0.00
10	Dahlberg	Nat. Gas	Sep-14	0	0	0.00	0	0	0.00	0	0	0.00
11	Dahlberg	Nat. Gas	Oct-14	0	0	0.00	0	0	0.00	0	0	0.00
12	Dahlberg	Nat. Gas	Nov-14	0	0	0.00	0	0	0.00	0	0	0.00
13	Dahlberg	Nat. Gas	Dec-14	0	0	0.00	0	0	0.00	0	0	0.00
14	Total									0	0	
15	Dahlberg	Nat. Gas	13 mth avg							0	0	0.00

16 Note: Gulf provides the fuel to operate these units per the Purchase Power Agreement.

17 Totals may not add due to rounding.

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide conventional fuel account balances in dollars and quantities for each fuel type for the test year and the two preceeding years. Include Natural Gas even though no Inventory is carried. (Give units in Barrels, Tons, or MCF)

Type of Data Shown:

X Projected Test Year Ended 12/31/14

____ Prior Year Ended 12/31/13

____ Historical Year Ended 12/31/12

Witness: M. L. Burroughs, S. D. Ritenour

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
				Beginning Inventory			Receipts			Fuel Issued to Generation		
Line No.	Plant	Fuel Type	Month	Units	($000)	$/Unit	Units	($000)	$/Unit	Units	($000)	$/Unit
1	Cent. AL	Nat. Gas	Dec-13	883,495	3,787	4.29	3,315,036	16,407	4.95	3,472,803	16,940	4.88
2	Cent. AL	Nat. Gas	Jan-14	725,728	3,254	4.48	3,047,830	15,492	5.08	3,047,830	15,416	5.06
3	Cent. AL	Nat. Gas	Feb-14	725,728	3,330	4.59	2,461,566	12,651	5.14	2,461,566	12,659	5.14
4	Cent. AL	Nat. Gas	Mar-14	725,728	3,322	4.58	1,726,917	9,008	5.22	1,726,917	9,068	5.25
5	Cent. AL	Nat. Gas	Apr-14	725,728	3,262	4.49	1,164,592	6,186	5.31	1,227,699	6,594	5.37
6	Cent. AL	Nat. Gas	May-14	662,621	2,854	4.31	1,281,463	6,845	5.34	1,249,909	6,702	5.36
7	Cent. AL	Nat. Gas	Jun-14	694,175	2,997	4.32	3,424,946	16,171	4.72	3,172,519	15,061	4.75
8	Cent. AL	Nat. Gas	Jul-14	946,602	4,107	4.34	3,718,909	17,568	4.72	3,718,909	17,539	4.72
9	Cent. AL	Nat. Gas	Aug-14	946,602	4,136	4.37	3,716,107	17,625	4.74	3,716,107	17,605	4.74
10	Cent. AL	Nat. Gas	Sep-14	946,602	4,156	4.39	3,296,487	15,700	4.76	3,328,040	15,838	4.76
11	Cent. AL	Nat. Gas	Oct-14	915,049	4,018	4.39	1,370,002	7,410	5.41	1,401,556	7,512	5.36
12	Cent. AL	Nat. Gas	Nov-14	883,495	3,916	4.43	2,588,278	13,107	5.06	2,588,278	13,025	5.03
13	Cent. AL	Nat. Gas	Dec-14	883,495	3,998	4.53	3,042,692	15,876	5.22	3,200,459	16,454	5.14

14 Note: Gulf provides the fuel to operate these units per the Purchase Power Agreement.

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide conventional fuel account balances in dollars and quantities for each fuel type for the test year and the two preceeding years. Include Natural Gas even though no inventory is carried. (Give units in Barrels, Tons, or MCF)

Type of Data Shown:

X Projected Test Year Ended 12/31/14

____ Prior Year Ended 12/31/13

____ Historical Year Ended 12/31/12

Witness: M. L. Burroughs, S. D. Ritenour

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
				Fuel Issues (Other)			Adjustments			Ending Inventory		
Line No.	Plant	Fuel Type	Month	Units	($000)	$/Unit	Units	($000)	$/Unit	Units	($000)	$/Unit
1	Cent. AL	Nat. Gas	Dec-13	0	0	0.00	0	0	0.00	725,728	3,254	4.48
2	Cent. AL	Nat. Gas	Jan-14	0	0	0.00	0	0	0.00	725,728	3,330	4.59
3	Cent. AL	Nat. Gas	Feb-14	0	0	0.00	0	0	0.00	725,728	3,322	4.58
4	Cent. AL	Nat. Gas	Mar-14	0	0	0.00	0	0	0.00	725,728	3,262	4.49
5	Cent. AL	Nat. Gas	Apr-14	0	0	0.00	0	0	0.00	662,621	2,854	4.31
6	Cent. AL	Nat. Gas	May-14	0	0	0.00	0	0	0.00	694,175	2,997	4.32
7	Cent. AL	Nat. Gas	Jun-14	0	0	0.00	0	0	0.00	946,602	4,107	4.34
8	Cent. AL	Nat. Gas	Jul-14	0	0	0.00	0	0	0.00	946,602	4,136	4.37
9	Cent. AL	Nat. Gas	Aug-14	0	0	0.00	0	0	0.00	946,602	4,156	4.39
10	Cent. AL	Nat. Gas	Sep-14	0	0	0.00	0	0	0.00	915,049	4,018	4.39
11	Cent. AL	Nat. Gas	Oct-14	0	0	0.00	0	0	0.00	883,495	3,916	4.43
12	Cent. AL	Nat. Gas	Nov-14	0	0	0.00	0	0	0.00	883,495	3,998	4.53
13	Cent. AL	Nat. Gas	Dec-14	0	0	0.00	0	0	0.00	725,728	3,420	4.71
14	Total									10,507,281	46,770	
15	Cent. AL	Nat. Gas	13 mth avg							808,252	3,598	4.45

16 Note: Gulf provides the fuel to operate these units per the Purchase Power Agreement.

17 Totals may not add due to rounding.

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide conventional fuel account balances in dollars and quantities for each fuel type for the test year and the two preceeding years. Include Natural Gas even though no inventory is carried. (Give units in Barrels, Tons, or MCF)

Type of Data Shown:

_____ Projected Test Year Ended 12/31/14

X Prior Year Ended 12/31/13

_____ Historical Year Ended 12/31/12

Witness: M. L. Burroughs, S. D. Ritenour

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
				Beginning Inventory			Receipts			Fuel Issued to Generation		
Line No.	Plant	Fuel Type	Month	Units	($000)	$/Unit	Units	($000)	$/Unit	Units	($000)	$/Unit
1	Crist	Coal (tons)	Dec-12	282,573	29,016	102.68	90,154	8,939	99.15	94,997	9,673	101.82
2	Crist	Coal (tons)	Jan-13	277,731	28,281	101.83	113,785	14,162	124.46	117,835	12,774	108.41
3	Crist	Coal (tons)	Feb-13	273,681	29,669	108.41	107,000	11,846	110.71	111,744	12,186	109.05
4	Crist	Coal (tons)	Mar-13	268,937	29,329	109.06	127,000	12,546	98.79	122,826	12,990	105.76
5	Crist	Coal (tons)	Apr-13	273,111	28,885	105.76	124,000	12,003	96.80	117,609	12,110	102.97
6	Crist	Coal (tons)	May-13	279,502	28,778	102.96	135,001	13,550	100.37	128,045	13,075	102.11
7	Crist	Coal (tons)	Jun-13	286,458	29,253	102.12	141,999	14,203	100.02	135,605	13,754	101.43
8	Crist	Coal (tons)	Jul-13	292,852	29,702	101.42	165,000	16,515	100.09	157,157	15,864	100.94
9	Crist	Coal (tons)	Aug-13	300,695	30,353	100.94	163,000	15,998	98.15	155,467	15,541	99.96
10	Crist	Coal (tons)	Sep-13	308,228	30,810	99.96	127,999	12,640	98.75	127,970	12,746	99.60
11	Crist	Coal (tons)	Oct-13	308,257	30,704	99.61	131,000	13,010	99.31	128,138	12,752	99.52
12	Crist	Coal (tons)	Nov-13	311,119	30,962	99.52	124,000	12,502	100.82	119,048	11,892	99.89
13	Crist	Coal (tons)	Dec-13	316,071	31,572	99.89	132,000	13,338	101.05	128,094	12,840	100.24

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide conventional fuel account balances in dollars and quantities for each fuel type for the test year and the two preceeding years. Include Natural Gas even though no inventory is carried. (Give units in Barrels, Tons, or MCF)

Type of Data Shown:

____ Projected Test Year Ended 12/31/14

X Prior Year Ended 12/31/13

____ Historical Year Ended 12/31/12

Witness: M. L. Burroughs, S. D. Ritenour

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
				Fuel Issues (Other)			Adjustments			Ending Inventory		
Line No.	Plant	Fuel Type	Month	Units	($000)	$/Unit	Units	($000)	$/Unit	Units	($000)	$/Unit
1	Crist	Coal (tons)	Dec-12	0	0	0.00	0	0	0.00	277,731	28,281	101.83
2	Crist	Coal (tons)	Jan-13	0	0	0.00	0	0	0.00	273,681	29,669	108.41
3	Crist	Coal (tons)	Feb-13	0	0	0.00	0	0	0.00	268,937	29,329	109.06
4	Crist	Coal (tons)	Mar-13	0	0	0.00	0	0	0.00	273,111	28,885	105.76
5	Crist	Coal (tons)	Apr-13	0	0	0.00	0	0	0.00	279,502	28,778	102.96
6	Crist	Coal (tons)	May-13	0	0	0.00	0	0	0.00	286,458	29,253	102.12
7	Crist	Coal (tons)	Jun-13	0	0	0.00	0	0	0.00	292,852	29,702	101.42
8	Crist	Coal (tons)	Jul-13	0	0	0.00	0	0	0.00	300,695	30,353	100.94
9	Crist	Coal (tons)	Aug-13	0	0	0.00	0	0	0.00	308,228	30,810	99.96
10	Crist	Coal (tons)	Sep-13	0	0	0.00	0	0	0.00	308,257	30,704	99.61
11	Crist	Coal (tons)	Oct-13	0	0	0.00	0	0	0.00	311,119	30,962	99.52
12	Crist	Coal (tons)	Nov-13	0	0	0.00	0	0	0.00	316,071	31,572	99.89
13	Crist	Coal (tons)	Dec-13	0	0	0.00	0	0	0.00	319,977	32,070	100.23
14	Total									3,816,619	390,368	
15	Crist	Coal (tons)	13 mth avg							293,586	30,028	102.28

16 Totals may not add due to rounding.

Supporting Schedules:

Recap Schedules:

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FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide conventional fuel account balances in dollars and quantities for each fuel type for the test year and the two preceeding years. Include Natural Gas even though no inventory is carried. (Give units in Barrels, Tons, or MCF)

Type of Data Shown:
- Projected Test Year Ended 12/31/14
- X — Prior Year Ended 12/31/13
- Historical Year Ended 12/31/12

Witness: M. L. Burroughs, S. D. Ritenour

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
				Beginning Inventory			Receipts			Fuel Issued to Generation		
Line No.	Plant	Fuel Type	Month	Units	($000)	$/Unit	Units	($000)	$/Unit	Units	($000)	$/Unit
1	Smith	Coal (tons)	Dec-12	211,418	23,497	111.14	24,241	2,463	101.60	24,646	2,715	110.16
2	Smith	Coal (tons)	Jan-13	211,013	23,245	110.16	37,999	6,727	177.03	41,963	5,051	120.37
3	Smith	Coal (tons)	Feb-13	207,049	24,921	120.36	33,999	4,624	136.00	33,979	4,165	122.58
4	Smith	Coal (tons)	Mar-13	207,069	25,380	122.57	38,001	5,081	133.71	48,341	6,009	124.30
5	Smith	Coal (tons)	Apr-13	196,729	24,452	124.29	44,000	5,733	130.30	44,183	5,540	125.39
6	Smith	Coal (tons)	May-13	196,546	24,645	125.39	30,000	4,164	138.80	30,383	3,864	127.18
7	Smith	Coal (tons)	Jun-13	196,163	24,945	127.16	30,001	4,163	138.76	33,009	4,248	128.69
8	Smith	Coal (tons)	Jul-13	193,155	24,860	128.70	30,001	4,164	138.80	44,556	5,795	130.06
9	Smith	Coal (tons)	Aug-13	178,600	23,229	130.06	29,999	4,163	138.77	42,604	5,594	131.30
10	Smith	Coal (tons)	Sep-13	165,995	21,798	131.32	30,001	4,164	138.80	29,954	3,968	132.47
11	Smith	Coal (tons)	Oct-13	166,042	21,994	132.46	30,000	4,164	138.80	36,238	4,835	133.42
12	Smith	Coal (tons)	Nov-13	159,804	21,323	133.43	29,999	4,163	138.77	35,107	4,714	134.28
13	Smith	Coal (tons)	Dec-13	154,696	20,772	134.28	30,000	4,164	138.80	44,213	5,969	135.01

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide conventional fuel account balances in dollars and quantities for each fuel type for the test year and the two preceeding years. Include Natural Gas even though no inventory is carried. (Give units in Barrels, Tons, or MCF)

Type of Data Shown:

_____ Projected Test Year Ended 12/31/14

X Prior Year Ended 12/31/13

_____ Historical Year Ended 12/31/12

Witness: M. L. Burroughs, S. D. Ritenour

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
				Fuel Issues (Other)			Adjustments			Ending Inventory		
Line No.	Plant	Fuel Type	Month	Units	($000)	$/Unit	Units	($000)	$/Unit	Units	($000)	$/Unit
1	Smith	Coal (tons)	Dec-12	0	0	0.00	0	0	0.00	211,013	23,245	110.16
2	Smith	Coal (tons)	Jan-13	0	0	0.00	0	0	0.00	207,049	24,921	120.36
3	Smith	Coal (tons)	Feb-13	0	0	0.00	0	0	0.00	207,069	25,380	122.57
4	Smith	Coal (tons)	Mar-13	0	0	0.00	0	0	0.00	196,729	24,452	124.29
5	Smith	Coal (tons)	Apr-13	0	0	0.00	0	0	0.00	196,546	24,645	125.39
6	Smith	Coal (tons)	May-13	0	0	0.00	0	0	0.00	196,163	24,945	127.16
7	Smith	Coal (tons)	Jun-13	0	0	0.00	0	0	0.00	193,155	24,860	128.70
8	Smith	Coal (tons)	Jul-13	0	0	0.00	0	0	0.00	178,600	23,229	130.06
9	Smith	Coal (tons)	Aug-13	0	0	0.00	0	0	0.00	165,995	21,798	131.32
10	Smith	Coal (tons)	Sep-13	0	0	0.00	0	0	0.00	166,042	21,994	132.46
11	Smith	Coal (tons)	Oct-13	0	0	0.00	0	0	0.00	159,804	21,323	133.43
12	Smith	Coal (tons)	Nov-13	0	0	0.00	0	0	0.00	154,696	20,772	134.28
13	Smith	Coal (tons)	Dec-13	0	0	0.00	0	0	0.00	140,483	18,967	135.01
14	Total									2,373,344	300,531	
15	Smith	Coal (tons)	13 mth avg							182,565	23,118	126.63

16 Totals may not add due to rounding.

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide conventional fuel account balances in dollars and quantities for each fuel type for the test year and the two preceeding years. Include Natural Gas even though no inventory is carried. (Give units in Barrels, Tons, or MCF)

Type of Data Shown:
_____ Projected Test Year Ended 12/31/14
X Prior Year Ended 12/31/13
_____ Historical Year Ended 12/31/12

Witness: M. L. Burroughs, S. D. Ritenour

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
				Beginning Inventory			Receipts			Fuel Issued to Generation		
Line No.	Plant	Fuel Type	Month	Units	($000)	$/Unit	Units	($000)	$/Unit	Units	($000)	$/Unit
1	Scholz	Coal (tons)	Dec-12	37,396	3,252	86.96	0	0	0.00	0	0	0.00
2	Scholz	Coal (tons)	Jan-13	37,396	3,252	86.96	-1	-1	1000.00	2,468	214	86.71
3	Scholz	Coal (tons)	Feb-13	34,927	3,037	86.95	1	0	0.00	1,197	104	86.88
4	Scholz	Coal (tons)	Mar-13	33,731	2,933	86.95	0	0	0.00	0	0	0.00
5	Scholz	Coal (tons)	Apr-13	33,731	2,933	86.95	0	0	0.00	0	0	0.00
6	Scholz	Coal (tons)	May-13	33,731	2,933	86.95	0	0	0.00	0	0	0.00
7	Scholz	Coal (tons)	Jun-13	33,731	2,933	86.95	1	0	0.00	2,067	180	87.08
8	Scholz	Coal (tons)	Jul-13	31,665	2,753	86.94	0	-1	0.00	2,078	180	86.62
9	Scholz	Coal (tons)	Aug-13	29,587	2,572	86.93	-1	0	0.00	3,718	323	86.87
10	Scholz	Coal (tons)	Sep-13	25,868	2,249	86.94	0	0	0.00	0	0	0.00
11	Scholz	Coal (tons)	Oct-13	25,868	2,249	86.94	0	0	0.00	0	0	0.00
12	Scholz	Coal (tons)	Nov-13	25,868	2,249	86.94	0	0	0.00	0	0	0.00
13	Scholz	Coal (tons)	Dec-13	25,868	2,249	86.94	1	0	0.00	1,197	104	86.88

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide conventional fuel account balances in dollars and quantities for each fuel type for the test year and the two preceeding years. Include Natural Gas even though no Inventory is carried. (Give units in Barrels, Tons, or MCF)

Type of Data Shown:
_____ Projected Test Year Ended 12/31/14
X Prior Year Ended 12/31/13
_____ Historical Year Ended 12/31/12
Witness: M. L. Burroughs, S. D. Ritenour

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
				Fuel Issues (Other)			Adjustments			Ending Inventory		
Line No.	Plant	Fuel Type	Month	Units	($000)	$/Unit	Units	($000)	$/Unit	Units	($000)	$/Unit
1	Scholz	Coal (tons)	Dec-12	0	0	0.00	0	0	0.00	37,396	3,252	86.96
2	Scholz	Coal (tons)	Jan-13	0	0	0.00	0	0	0.00	34,927	3,037	86.95
3	Scholz	Coal (tons)	Feb-13	0	0	0.00	0	0	0.00	33,731	2,933	86.95
4	Scholz	Coal (tons)	Mar-13	0	0	0.00	0	0	0.00	33,731	2,933	86.95
5	Scholz	Coal (tons)	Apr-13	0	0	0.00	0	0	0.00	33,731	2,933	86.95
6	Scholz	Coal (tons)	May-13	0	0	0.00	0	0	0.00	33,731	2,933	86.95
7	Scholz	Coal (tons)	Jun-13	0	0	0.00	0	0	0.00	31,665	2,753	86.94
8	Scholz	Coal (tons)	Jul-13	0	0	0.00	0	0	0.00	29,587	2,572	86.93
9	Scholz	Coal (tons)	Aug-13	0	0	0.00	0	0	0.00	25,868	2,249	86.94
10	Scholz	Coal (tons)	Sep-13	0	0	0.00	0	0	0.00	25,868	2,249	86.94
11	Scholz	Coal (tons)	Oct-13	0	0	0.00	0	0	0.00	25,868	2,249	86.94
12	Scholz	Coal (tons)	Nov-13	0	0	0.00	0	0	0.00	25,868	2,249	86.94
13	Scholz	Coal (tons)	Dec-13	0	0	0.00	0	0	0.00	24,672	2,145	86.94
14	Total									396,643	34,487	
15	Scholz	Coal (tons)	13 mth avg							30,511	2,653	86.95

16 Totals may not add due to rounding.

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide conventional fuel account balances in dollars and quantities for each fuel type for the test year and the two preceeding years. Include Natural Gas even though no inventory is carried. (Give units in Barrels, Tons, or MCF)

Type of Data Shown:

_____ Projected Test Year Ended 12/31/14

X Prior Year Ended 12/31/13

_____ Historical Year Ended 12/31/12

Witness: M. L. Burroughs, S. D. Ritenour

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
				Beginning Inventory			Receipts			Fuel Issued to Generation		
Line No.	Plant	Fuel Type	Month	Units	($000)	$/Unit	Units	($000)	$/Unit	Units	($000)	$/Unit
1	Daniel	Coal (tons)	Dec-12	375,296	38,959	103.81	36,772	5,142	139.83	0	0	0.00
2	Daniel	Coal (tons)	Jan-13	412,068	44,101	107.02	12,200	284	23.28	34,240	3,582	104.61
3	Daniel	Coal (tons)	Feb-13	390,028	40,803	104.62	12,201	1,532	125.56	2,872	302	105.15
4	Daniel	Coal (tons)	Mar-13	399,357	42,033	105.25	18,300	2,282	124.70	0	0	0.00
5	Daniel	Coal (tons)	Apr-13	417,657	44,315	106.10	12,200	1,519	124.51	0	0	0.00
6	Daniel	Coal (tons)	May-13	429,857	45,834	106.63	12,200	1,527	125.16	0	0	0.00
7	Daniel	Coal (tons)	Jun-13	442,057	47,361	107.14	18,300	2,305	125.96	46,587	5,026	107.88
8	Daniel	Coal (tons)	Jul-13	413,770	44,640	107.89	30,499	3,836	125.77	74,825	8,164	109.11
9	Daniel	Coal (tons)	Aug-13	369,444	40,312	109.12	30,500	3,847	126.13	77,337	8,539	110.41
10	Daniel	Coal (tons)	Sep-13	322,607	35,620	110.41	30,501	3,891	127.57	44,576	4,988	111.90
11	Daniel	Coal (tons)	Oct-13	308,532	34,523	111.89	30,500	3,905	128.03	9,462	1,072	113.30
12	Daniel	Coal (tons)	Nov-13	329,570	37,356	113.35	30,500	3,895	127.70	17,018	1,949	114.53
13	Daniel	Coal (tons)	Dec-13	343,052	39,302	114.57	28,074	3,600	128.23	9,839	1,137	115.56

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide conventional fuel account balances in dollars and quantities for each fuel type for the test year and the two preceeding years. Include Natural Gas even though no inventory is carried. (Give units in Barrels, Tons, or MCF)

Type of Data Shown:
____ Projected Test Year Ended 12/31/14
X Prior Year Ended 12/31/13
____ Historical Year Ended 12/31/12

Witness: M. L. Burroughs, S. D. Ritenour

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
				Fuel Issues (Other)			Adjustments			Ending Inventory		
Line No.	Plant	Fuel Type	Month	Units	($000)	$/Unit	Units	($000)	$/Unit	Units	($000)	$/Unit
1	Daniel	Coal (tons)	Dec-12	0	0	0.00	0	0	0.00	412,068	44,101	107.02
2	Daniel	Coal (tons)	Jan-13	0	0	0.00	0	0	0.00	390,028	40,803	104.62
3	Daniel	Coal (tons)	Feb-13	0	0	0.00	0	0	0.00	399,357	42,033	105.25
4	Daniel	Coal (tons)	Mar-13	0	0	0.00	0	0	0.00	417,657	44,315	106.10
5	Daniel	Coal (tons)	Apr-13	0	0	0.00	0	0	0.00	429,857	45,834	106.63
6	Daniel	Coal (tons)	May-13	0	0	0.00	0	0	0.00	442,057	47,361	107.14
7	Daniel	Coal (tons)	Jun-13	0	0	0.00	0	0	0.00	413,770	44,640	107.89
8	Daniel	Coal (tons)	Jul-13	0	0	0.00	0	0	0.00	369,444	40,312	109.12
9	Daniel	Coal (tons)	Aug-13	0	0	0.00	0	0	0.00	322,607	35,620	110.41
10	Daniel	Coal (tons)	Sep-13	0	0	0.00	0	0	0.00	308,532	34,523	111.89
11	Daniel	Coal (tons)	Oct-13	0	0	0.00	0	0	0.00	329,570	37,356	113.35
12	Daniel	Coal (tons)	Nov-13	0	0	0.00	0	0	0.00	343,052	39,302	114.57
13	Daniel	Coal (tons)	Dec-13	0	0	0.00	0	0	0.00	361,287	41,765	115.60
14	Total									4,939,286	537,965	
15	Daniel	Coal (tons)	13 mth avg							379,945	41,382	108.92

16 Totals may not add due to rounding.

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide conventional fuel account balances in dollars and quantities for each fuel type for the test year and the two preceeding years. Include Natural Gas even though no inventory is carried. (Give units in Barrels, Tons, or MCF)

Type of Data Shown:
____ Projected Test Year Ended 12/31/14
X Prior Year Ended 12/31/13
____ Historical Year Ended 12/31/12

Witness: M. L. Burroughs, S. D. Ritenour

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
				Beginning Inventory			Receipts			Fuel Issued to Generation		
Line No.	Plant	Fuel Type	Month	Units	($000)	$/Unit	Units	($000)	$/Unit	Units	($000)	$/Unit
1	Scherer	Coal (tons)	Dec-12	166,774	7,409	44.43	51,608	2,387	46.25	59,629	2,675	44.86
2	Scherer	Coal (tons)	Jan-13	172,410	7,728	44.82	47,358	1,707	36.04	74,565	3,201	42.93
3	Scherer	Coal (tons)	Feb-13	145,203	6,234	42.93	38,696	1,744	45.07	19,161	831	43.37
4	Scherer	Coal (tons)	Mar-13	164,738	7,147	43.38	38,039	1,704	44.80	0	0	0.00
5	Scherer	Coal (tons)	Apr-13	202,777	8,851	43.65	55,824	2,495	44.69	57,873	2,539	43.87
6	Scherer	Coal (tons)	May-13	200,728	8,807	43.88	54,575	2,448	44.88	72,818	3,210	44.08
7	Scherer	Coal (tons)	Jun-13	182,485	8,045	44.09	55,978	2,513	44.89	73,476	3,253	44.27
8	Scherer	Coal (tons)	Jul-13	164,987	7,305	44.28	68,325	3,061	44.80	77,410	3,439	44.43
9	Scherer	Coal (tons)	Aug-13	155,902	6,927	44.43	65,353	2,937	44.94	77,767	3,467	44.58
10	Scherer	Coal (tons)	Sep-13	143,488	6,397	44.58	67,013	3,021	45.08	74,026	3,312	44.74
11	Scherer	Coal (tons)	Oct-13	136,475	6,106	44.74	71,232	3,225	45.27	78,897	3,544	44.92
12	Scherer	Coal (tons)	Nov-13	128,810	5,787	44.93	71,587	3,239	45.25	74,423	3,352	45.04
13	Scherer	Coal (tons)	Dec-13	125,974	5,674	45.04	66,100	2,996	45.33	82,743	3,735	45.14

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide conventional fuel account balances in dollars and quantities for each fuel type for the test year and the two preceeding years. Include Natural Gas even though no inventory is carried. (Give units in Barrels, Tons, or MCF)

Type of Data Shown:
_____ Projected Test Year Ended 12/31/14
X Prior Year Ended 12/31/13
_____ Historical Year Ended 12/31/12
Witness: M. L. Burroughs, S. D. Ritenour

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
				Fuel Issues (Other)			Adjustments			Ending Inventory		
Line No.	Plant	Fuel Type	Month	Units	($000)	$/Unit	Units	($000)	$/Unit	Units	($000)	$/Unit
1	Scherer	Coal (tons)	Dec-12	0	0	0.00	13,658	606	0.00	172,410	7,728	44.82
2	Scherer	Coal (tons)	Jan-13	0	0	0.00	0	0	0.00	145,203	6,234	42.93
3	Scherer	Coal (tons)	Feb-13	0	0	0.00	0	0	0.00	164,738	7,147	43.38
4	Scherer	Coal (tons)	Mar-13	0	0	0.00	0	0	0.00	202,777	8,851	43.65
5	Scherer	Coal (tons)	Apr-13	0	0	0.00	0	0	0.00	200,728	8,807	43.88
6	Scherer	Coal (tons)	May-13	0	0	0.00	0	0	0.00	182,485	8,045	44.09
7	Scherer	Coal (tons)	Jun-13	0	0	0.00	0	0	0.00	164,987	7,305	44.28
8	Scherer	Coal (tons)	Jul-13	0	0	0.00	0	0	0.00	155,902	6,927	44.43
9	Scherer	Coal (tons)	Aug-13	0	0	0.00	0	0	0.00	143,488	6,397	44.58
10	Scherer	Coal (tons)	Sep-13	0	0	0.00	0	0	0.00	136,475	6,106	44.74
11	Scherer	Coal (tons)	Oct-13	0	0	0.00	0	0	0.00	128,810	5,787	44.93
12	Scherer	Coal (tons)	Nov-13	0	0	0.00	0	0	0.00	125,974	5,674	45.04
13	Scherer	Coal (tons)	Dec-13	0	0	0.00	0	0	0.00	109,331	4,935	45.14
14	Total									2,033,308	89,943	
15	Scherer	Coal (tons)	13 mth avg							156,408	6,919	44.24

16 Totals may not add due to rounding.

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide conventional fuel account balances in dollars and quantities for each fuel type for the test year and the two preceeding years. Include Natural Gas even though no inventory is carried. (Give units in Barrels, Tons, or MCF)

Type of Data Shown:

____ Projected Test Year Ended 12/31/14

X Prior Year Ended 12/31/13

____ Historical Year Ended 12/31/12

Witness: M. L. Burroughs, S. D. Ritenour

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
				Beginning Inventory			Receipts			Fuel Issued to Generation		
Line No.	Plant	Fuel Type	Month	Units	($000)	$/Unit	Units	($000)	$/Unit	Units	($000)	$/Unit
1	Cent. AL	CT Oil	Dec-12	9,283	770	82.95	0	0	0.00	0	0	0.00
2	Cent. AL	CT Oil	Jan-13	9,283	770	82.95	0	0	0.00	0	0	0.00
3	Cent. AL	CT Oil	Feb-13	9,283	770	82.95	0	0	0.00	0	0	0.00
4	Cent. AL	CT Oil	Mar-13	9,283	770	82.95	0	0	0.00	0	0	0.00
5	Cent. AL	CT Oil	Apr-13	9,283	770	82.95	0	0	0.00	0	0	0.00
6	Cent. AL	CT Oil	May-13	9,283	770	82.95	0	0	0.00	0	0	0.00
7	Cent. AL	CT Oil	Jun-13	9,283	770	82.95	0	0	0.00	0	0	0.00
8	Cent. AL	CT Oil	Jul-13	9,283	770	82.95	0	0	0.00	0	0	0.00
9	Cent. AL	CT Oil	Aug-13	9,283	770	82.95	0	0	0.00	0	0	0.00
10	Cent. AL	CT Oil	Sep-13	9,283	770	82.95	0	0	0.00	0	0	0.00
11	Cent. AL	CT Oil	Oct-13	9,283	770	82.95	0	0	0.00	0	0	0.00
12	Cent. AL	CT Oil	Nov-13	9,283	770	82.95	0	0	0.00	0	0	0.00
13	Cent. AL	CT Oil	Dec-13	9,283	770	82.95	0	0	0.00	0	0	0.00

14 Note: Gulf provides the fuel to operate these units per the Purchase Power Agreement.

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide conventional fuel account balances in dollars and quantities for each fuel type for the test year and the two preceeding years. Include Natural Gas even though no inventory is carried. (Give units in Barrels, Tons, or MCF)

Type of Data Shown:

____ Projected Test Year Ended 12/31/14

X Prior Year Ended 12/31/13

____ Historical Year Ended 12/31/12

Witness: M. L. Burroughs, S. D. Ritenour

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
				Fuel Issues (Other)			Adjustments			Ending Inventory		
Line No.	Plant	Fuel Type	Month	Units	($000)	$/Unit	Units	($000)	$/Unit	Units	($000)	$/Unit
1	Cent. AL	CT Oil	Dec-12	0	0	0.00	0	0	0.00	9,283	770	82.95
2	Cent. AL	CT Oil	Jan-13	0	0	0.00	0	0	0.00	9,283	770	82.95
3	Cent. AL	CT Oil	Feb-13	0	0	0.00	0	0	0.00	9,283	770	82.95
4	Cent. AL	CT Oil	Mar-13	0	0	0.00	0	0	0.00	9,283	770	82.95
5	Cent. AL	CT Oil	Apr-13	0	0	0.00	0	0	0.00	9,283	770	82.95
6	Cent. AL	CT Oil	May-13	0	0	0.00	0	0	0.00	9,283	770	82.95
7	Cent. AL	CT Oil	Jun-13	0	0	0.00	0	0	0.00	9,283	770	82.95
8	Cent. AL	CT Oil	Jul-13	0	0	0.00	0	0	0.00	9,283	770	82.95
9	Cent. AL	CT Oil	Aug-13	0	0	0.00	0	0	0.00	9,283	770	82.95
10	Cent. AL	CT Oil	Sep-13	0	0	0.00	0	0	0.00	9,283	770	82.95
11	Cent. AL	CT Oil	Oct-13	0	0	0.00	0	0	0.00	9,283	770	82.95
12	Cent. AL	CT Oil	Nov-13	0	0	0.00	0	0	0.00	9,283	770	82.95
13	Cent. AL	CT Oil	Dec-13	0	0	0.00	0	0	0.00	9,283	770	82.95
14	Total									120,679	10,010	
15	Cent. AL	CT Oil	13 mth avg							9,283	770	82.95

16 Note: Gulf provides the fuel to operate these units per the Purchase Power Agreement.

17 Totals may not add due to rounding.

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide conventional fuel account balances in dollars and quantities for each fuel type for the test year and the two preceeding years. Include Natural Gas even though no inventory is carried. (Give units in Barrels, Tons, or MCF)

Type of Data Shown:

____ Projected Test Year Ended 12/31/14

X Prior Year Ended 12/31/13

____ Historical Year Ended 12/31/12

Witness: M. L. Burroughs, S. D. Ritenour

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
				Beginning Inventory			Receipts			Fuel Issued to Generation		
Line No.	Plant	Fuel Type	Month	Units	($000)	$/Unit	Units	($000)	$/Unit	Units	($000)	$/Unit
1	Baconton	CT Oil	Dec-12	8,077	696	86.17	0	0	0.00	0	0	0.00
2	Baconton	CT Oil	Jan-13	8,077	696	86.17	0	0	0.00	0	0	0.00
3	Baconton	CT Oil	Feb-13	8,077	696	86.17	0	0	0.00	0	0	0.00
4	Baconton	CT Oil	Mar-13	8,077	696	86.17	0	0	0.00	0	0	0.00
5	Baconton	CT Oil	Apr-13	8,077	696	86.17	0	0	0.00	0	0	0.00
6	Baconton	CT Oil	May-13	8,077	696	86.17	0	0	0.00	0	0	0.00
7	Baconton	CT Oil	Jun-13	8,077	696	86.17	0	0	0.00	0	0	0.00
8	Baconton	CT Oil	Jul-13	8,077	696	86.17	0	0	0.00	0	0	0.00
9	Baconton	CT Oil	Aug-13	8,077	696	86.17	0	0	0.00	0	0	0.00
10	Baconton	CT Oil	Sep-13	8,077	696	86.17	0	0	0.00	0	0	0.00
11	Baconton	CT Oil	Oct-13	8,077	696	86.17	0	0	0.00	0	0	0.00
12	Baconton	CT Oil	Nov-13	8,077	696	86.17	0	0	0.00	0	0	0.00
13	Baconton	CT Oil	Dec-13	8,077	696	86.17	0	0	0.00	0	0	0.00

14 Note: Gulf provides the fuel to operate these units per the Purchase Power Agreement.

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide conventional fuel account balances in dollars and quantities for each fuel type for the test year and the two preceeding years. Include Natural Gas even though no inventory is carried. (Give units in Barrels, Tons, or MCF)

Type of Data Shown:
____ Projected Test Year Ended 12/31/14
X Prior Year Ended 12/31/13
____ Historical Year Ended 12/31/12

Witness: M. L. Burroughs, S. D. Ritenour

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
				Fuel Issues (Other)			Adjustments			Ending Inventory		
Line No.	Plant	Fuel Type	Month	Units	($000)	$/Unit	Units	($000)	$/Unit	Units	($000)	$/Unit
1	Baconton	CT Oil	Dec-12	0	0	0.00	0	0	0.00	8,077	696	86.17
2	Baconton	CT Oil	Jan-13	0	0	0.00	0	0	0.00	8,077	696	86.17
3	Baconton	CT Oil	Feb-13	0	0	0.00	0	0	0.00	8,077	696	86.17
4	Baconton	CT Oil	Mar-13	0	0	0.00	0	0	0.00	8,077	696	86.17
5	Baconton	CT Oil	Apr-13	0	0	0.00	0	0	0.00	8,077	696	86.17
6	Baconton	CT Oil	May-13	0	0	0.00	0	0	0.00	8,077	696	86.17
7	Baconton	CT Oil	Jun-13	0	0	0.00	0	0	0.00	8,077	696	86.17
8	Baconton	CT Oil	Jul-13	0	0	0.00	0	0	0.00	8,077	696	86.17
9	Baconton	CT Oil	Aug-13	0	0	0.00	0	0	0.00	8,077	696	86.17
10	Baconton	CT Oil	Sep-13	0	0	0.00	0	0	0.00	8,077	696	86.17
11	Baconton	CT Oil	Oct-13	0	0	0.00	0	0	0.00	8,077	696	86.17
12	Baconton	CT Oil	Nov-13	0	0	0.00	0	0	0.00	8,077	696	86.17
13	Baconton	CT Oil	Dec-13	0	0	0.00	0	0	0.00	8,077	696	86.17
14	Total									105,001	9,048	
15	Baconton	CT Oil	13 mth avg							8,077	696	86.17

16 Note: Gulf provides the fuel to operate these units per the Purchase Power Agreement.
17 Totals may not add due to rounding.

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide conventional fuel account balances in dollars and quantities for each fuel type for the test year and the two preceeding years. Include Natural Gas even though no inventory is carried. (Give units in Barrels, Tons, or MCF)

Type of Data Shown:
____ Projected Test Year Ended 12/31/14
X Prior Year Ended 12/31/13
____ Historical Year Ended 12/31/12

Witness: M. L. Burroughs, S. D. Ritenour

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
				Beginning Inventory			Receipts			Fuel Issued to Generation		
Line No.	Plant	Fuel Type	Month	Units	($000)	$/Unit	Units	($000)	$/Unit	Units	($000)	$/Unit
1	Dahlberg	CT Oil	Dec-12	10,998	990	90.02	0	0	0.00	87	8	91.95
2	Dahlberg	CT Oil	Jan-13	10,911	982	90.00	0	0	0.00	0	0	0.00
3	Dahlberg	CT Oil	Feb-13	10,911	982	90.00	0	0	0.00	0	0	0.00
4	Dahlberg	CT Oil	Mar-13	10,911	982	90.00	0	0	0.00	0	0	0.00
5	Dahlberg	CT Oil	Apr-13	10,911	982	90.00	0	0	0.00	0	0	0.00
6	Dahlberg	CT Oil	May-13	10,911	982	90.00	0	0	0.00	0	0	0.00
7	Dahlberg	CT Oil	Jun-13	10,911	982	90.00	0	0	0.00	0	0	0.00
8	Dahlberg	CT Oil	Jul-13	10,911	982	90.00	0	0	0.00	0	0	0.00
9	Dahlberg	CT Oil	Aug-13	10,911	982	90.00	0	0	0.00	0	0	0.00
10	Dahlberg	CT Oil	Sep-13	10,911	982	90.00	0	0	0.00	0	0	0.00
11	Dahlberg	CT Oil	Oct-13	10,911	982	90.00	0	0	0.00	0	0	0.00
12	Dahlberg	CT Oil	Nov-13	10,911	982	90.00	0	0	0.00	0	0	0.00
13	Dahlberg	CT Oil	Dec-13	10,911	982	90.00	0	0	0.00	0	0	0.00

14 Note: Gulf provides the fuel to operate these units per the Purchase Power Agreement.

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide conventional fuel account balances in dollars and quantities for each fuel type for the test year and the two preceeding years. Include Natural Gas even though no inventory is carried. (Give units in Barrels, Tons, or MCF)

Type of Data Shown:

____ Projected Test Year Ended 12/31/14

X Prior Year Ended 12/31/13

____ Historical Year Ended 12/31/12

Witness: M. L. Burroughs, S. D. Ritenour

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
				Fuel Issues (Other)			Adjustments			Ending Inventory		
Line No.	Plant	Fuel Type	Month	Units	($000)	$/Unit	Units	($000)	$/Unit	Units	($000)	$/Unit
1	Dahlberg	CT Oil	Dec-12	0	0	0.00	0	0	0.00	10,911	982	90.00
2	Dahlberg	CT Oil	Jan-13	0	0	0.00	0	0	0.00	10,911	982	90.00
3	Dahlberg	CT Oil	Feb-13	0	0	0.00	0	0	0.00	10,911	982	90.00
4	Dahlberg	CT Oil	Mar-13	0	0	0.00	0	0	0.00	10,911	982	90.00
5	Dahlberg	CT Oil	Apr-13	0	0	0.00	0	0	0.00	10,911	982	90.00
6	Dahlberg	CT Oil	May-13	0	0	0.00	0	0	0.00	10,911	982	90.00
7	Dahlberg	CT Oil	Jun-13	0	0	0.00	0	0	0.00	10,911	982	90.00
8	Dahlberg	CT Oil	Jul-13	0	0	0.00	0	0	0.00	10,911	982	90.00
9	Dahlberg	CT Oil	Aug-13	0	0	0.00	0	0	0.00	10,911	982	90.00
10	Dahlberg	CT Oil	Sep-13	0	0	0.00	0	0	0.00	10,911	982	90.00
11	Dahlberg	CT Oil	Oct-13	0	0	0.00	0	0	0.00	10,911	982	90.00
12	Dahlberg	CT Oil	Nov-13	0	0	0.00	0	0	0.00	10,911	982	90.00
13	Dahlberg	CT Oil	Dec-13	0	0	0.00	0	0	0.00	10,911	982	90.00
14	Total									141,843	12,766	
15	Dahlberg	CT Oil	13 mth avg							10,911	982	90.00

16 Note: Gulf provides the fuel to operate these units per the Purchase Power Agreement.

17 Totals may not add due to rounding.

Supporting Schedules:

Recap Schedules:

Schedule B-18 | FUEL INVENTORY BY PLANT | Page 55 of 114

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide conventional fuel account balances in dollars and quantities for each fuel type for the test year and the two preceeding years. Include Natural Gas even though no inventory is carried. (Give units in Barrels, Tons, or MCF)

Type of Data Shown:
____ Projected Test Year Ended 12/31/14
X Prior Year Ended 12/31/13
____ Historical Year Ended 12/31/12
Witness: M. L. Burroughs, S. D. Ritenour

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
				Beginning Inventory			Receipts			Fuel Issued to Generation		
Line No.	Plant	Fuel Type	Month	Units	($000)	$/Unit	Units	($000)	$/Unit	Units	($000)	$/Unit
1	Smith	CT Oil	Dec-12	6,120	653	106.70	0	0	0.00	93	10	107.53
2	Smith	CT Oil	Jan-13	5,955	635	106.63	1188	143	120.37	0	0	0.00
3	Smith	CT Oil	Feb-13	7,143	778	108.92	0	0	0.00	0	0	0.00
4	Smith	CT Oil	Mar-13	7,143	778	108.92	0	0	0.00	0	0	0.00
5	Smith	CT Oil	Apr-13	7,143	778	108.92	0	0	0.00	0	0	0.00
6	Smith	CT Oil	May-13	7,143	778	108.92	0	0	0.00	0	0	0.00
7	Smith	CT Oil	Jun-13	7,143	778	108.92	0	0	0.00	0	0	0.00
8	Smith	CT Oil	Jul-13	7,143	778	108.92	0	0	0.00	0	0	0.00
9	Smith	CT Oil	Aug-13	7,143	778	108.92	0	0	0.00	0	0	0.00
10	Smith	CT Oil	Sep-13	7,143	778	108.92	0	0	0.00	0	0	0.00
11	Smith	CT Oil	Oct-13	7,143	778	108.92	0	0	0.00	0	0	0.00
12	Smith	CT Oil	Nov-13	7,143	778	108.92	0	0	0.00	0	0	0.00
13	Smith	CT Oil	Dec-13	7,143	778	108.92	0	0	0.00	0	0	0.00

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide conventional fuel account balances in dollars and quantities for each fuel type for the test year and the two preceeding years. Include Natural Gas even though no inventory is carried. (Give units in Barrels, Tons, or MCF)

Type of Data Shown:
____ Projected Test Year Ended 12/31/14
X Prior Year Ended 12/31/13
____ Historical Year Ended 12/31/12
Witness: M. L. Burroughs, S. D. Ritenour

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
				Fuel Issues (Other)			Adjustments			Ending Inventory		
Line No.	Plant	Fuel Type	Month	Units	($000)	$/Unit	Units	($000)	$/Unit	Units	($000)	$/Unit
1	Smith	CT Oil	Dec-12	0	0	0.00	-73	-8	109.59	5,955	635	106.63
2	Smith	CT Oil	Jan-13	0	0	0.00	0	0	0.00	7,143	778	108.92
3	Smith	CT Oil	Feb-13	0	0	0.00	0	0	0.00	7,143	778	108.92
4	Smith	CT Oil	Mar-13	0	0	0.00	0	0	0.00	7,143	778	108.92
5	Smith	CT Oil	Apr-13	0	0	0.00	0	0	0.00	7,143	778	108.92
6	Smith	CT Oil	May-13	0	0	0.00	0	0	0.00	7,143	778	108.92
7	Smith	CT Oil	Jun-13	0	0	0.00	0	0	0.00	7,143	778	108.92
8	Smith	CT Oil	Jul-13	0	0	0.00	0	0	0.00	7,143	778	108.92
9	Smith	CT Oil	Aug-13	0	0	0.00	0	0	0.00	7,143	778	108.92
10	Smith	CT Oil	Sep-13	0	0	0.00	0	0	0.00	7,143	778	108.92
11	Smith	CT Oil	Oct-13	0	0	0.00	0	0	0.00	7,143	778	108.92
12	Smith	CT Oil	Nov-13	0	0	0.00	0	0	0.00	7,143	778	108.92
13	Smith	CT Oil	Dec-13	0	0	0.00	0	0	0.00	7,143	778	108.92
14	Total									91,671	9,971	
15	Smith	CT Oil	13 mth avg							7,052	767	108.76

16 Totals may not add due to rounding.

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide conventional fuel account balances in dollars and quantities for each fuel type for the test year and the two preceeding years. Include Natural Gas even though no inventory is carried. (Give units in Barrels, Tons, or MCF)

Type of Data Shown:

____ Projected Test Year Ended 12/31/14

X Prior Year Ended 12/31/13

____ Historical Year Ended 12/31/12

Witness: M. L. Burroughs, S. D. Ritenour

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
				Beginning Inventory			Receipts			Fuel Issued to Generation		
Line No.	Plant	Fuel Type	Month	Units	($000)	$/Unit	Units	($000)	$/Unit	Units	($000)	$/Unit
1	Crist	Oil	Dec-12	2,826	340	120.31	0	0	0.00	175	21	120.00
2	Crist	Oil	Jan-13	2,652	319	120.29	1816	231	127.20	182	22	120.88
3	Crist	Oil	Feb-13	4,286	528	123.19	182	23	126.37	182	22	120.88
4	Crist	Oil	Mar-13	4,286	529	123.43	182	23	126.37	182	22	120.88
5	Crist	Oil	Apr-13	4,286	530	123.66	182	22	120.88	182	22	120.88
6	Crist	Oil	May-13	4,286	530	123.66	182	23	126.37	182	22	120.88
7	Crist	Oil	Jun-13	4,286	531	123.89	182	23	126.37	182	22	120.88
8	Crist	Oil	Jul-13	4,286	532	124.13	182	22	120.88	182	22	120.88
9	Crist	Oil	Aug-13	4,286	532	124.13	182	23	126.37	182	22	120.88
10	Crist	Oil	Sep-13	4,286	533	124.36	182	22	120.88	182	22	120.88
11	Crist	Oil	Oct-13	4,286	533	124.36	154	20	129.87	154	19	123.38
12	Crist	Oil	Nov-13	4,286	534	124.59	182	22	120.88	182	22	120.88
13	Crist	Oil	Dec-13	4,286	534	124.59	182	23	126.37	182	22	120.88

Supporting Schedules:

Recap Schedules:

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FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide conventional fuel account balances in dollars and quantities for each fuel type for the test year and the two preceeding years. Include Natural Gas even though no inventory is carried. (Give units in Barrels, Tons, or MCF)

Type of Data Shown:

____ Projected Test Year Ended 12/31/14

X Prior Year Ended 12/31/13

____ Historical Year Ended 12/31/12

Witness: M. L. Burroughs, S. D. Ritenour

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
				Fuel Issues (Other)			Adjustments			Ending Inventory		
Line No.	Plant	Fuel Type	Month	Units	($000)	$/Unit	Units	($000)	$/Unit	Units	($000)	$/Unit
1	Crist	Oil	Dec-12	0	0	0.00	0	0	0.00	2,652	319	120.29
2	Crist	Oil	Jan-13	0	0	0.00	0	0	0.00	4,286	528	123.19
3	Crist	Oil	Feb-13	0	0	0.00	0	0	0.00	4,286	529	123.43
4	Crist	Oil	Mar-13	0	0	0.00	0	0	0.00	4,286	530	123.66
5	Crist	Oil	Apr-13	0	0	0.00	0	0	0.00	4,286	530	123.66
6	Crist	Oil	May-13	0	0	0.00	0	0	0.00	4,286	531	123.89
7	Crist	Oil	Jun-13	0	0	0.00	0	0	0.00	4,286	532	124.13
8	Crist	Oil	Jul-13	0	0	0.00	0	0	0.00	4,286	532	124.13
9	Crist	Oil	Aug-13	0	0	0.00	0	0	0.00	4,286	533	124.36
10	Crist	Oil	Sep-13	0	0	0.00	0	0	0.00	4,286	533	124.36
11	Crist	Oil	Oct-13	0	0	0.00	0	0	0.00	4,286	534	124.59
12	Crist	Oil	Nov-13	0	0	0.00	0	0	0.00	4,286	534	124.59
13	Crist	Oil	Dec-13	0	0	0.00	0	0	0.00	4,286	535	124.83
14	Total									54,084	6,700	
15	Crist	Oil	13 mth avg							4,160	515	123.80

16 Totals may not add due to rounding.

Supporting Schedules:

Recap Schedules:

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FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide conventional fuel account balances in dollars and quantities for each fuel type for the test year and the two preceeding years. Include Natural Gas even though no inventory is carried. (Give units in Barrels, Tons, or MCF)

Type of Data Shown:

_____ Projected Test Year Ended 12/31/14

X Prior Year Ended 12/31/13

_____ Historical Year Ended 12/31/12

Witness: M. L. Burroughs, S. D. Ritenour

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
				Beginning Inventory			Receipts			Fuel Issued to Generation		
Line No.	Plant	Fuel Type	Month	Units	($000)	$/Unit	Units	($000)	$/Unit	Units	($000)	$/Unit
1	Smith	Oil	Dec-12	178	24	134.83	0	0	0.00	28	4	142.86
2	Smith	Oil	Jan-13	457	61	133.48	418	51	122.01	399	51	127.82
3	Smith	Oil	Feb-13	476	61	128.15	399	51	127.82	399	51	127.82
4	Smith	Oil	Mar-13	476	61	128.15	399	51	127.82	399	51	127.82
5	Smith	Oil	Apr-13	476	61	128.15	399	51	127.82	399	51	127.82
6	Smith	Oil	May-13	476	61	128.15	399	51	127.82	399	51	127.82
7	Smith	Oil	Jun-13	476	61	128.15	399	51	127.82	399	51	127.82
8	Smith	Oil	Jul-13	476	61	128.15	399	51	127.82	399	51	127.82
9	Smith	Oil	Aug-13	476	61	128.15	399	51	127.82	399	51	127.82
10	Smith	Oil	Sep-13	476	61	128.15	399	51	127.82	399	51	127.82
11	Smith	Oil	Oct-13	476	61	128.15	399	51	127.82	399	51	127.82
12	Smith	Oil	Nov-13	476	61	128.15	399	51	127.82	399	51	127.82
13	Smith	Oil	Dec-13	476	61	128.15	399	51	127.82	399	51	127.82

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide conventional fuel account balances in dollars and quantities for each fuel type for the test year and the two preceeding years. Include Natural Gas even though no inventory is carried. (Give units in Barrels, Tons, or MCF)

Type of Data Shown:

____ Projected Test Year Ended 12/31/14

X Prior Year Ended 12/31/13

____ Historical Year Ended 12/31/12

Witness: M. L. Burroughs, S. D. Ritenour

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
				Fuel Issues (Other)			Adjustments			Ending Inventory		
Line No.	Plant	Fuel Type	Month	Units	($000)	$/Unit	Units	($000)	$/Unit	Units	($000)	$/Unit
1	Smith	Oil	Dec-12	0	0	0.00	307	41	133.55	457	61	133.48
2	Smith	Oil	Jan-13	0	0	0.00	0	0	0.00	476	61	128.15
3	Smith	Oil	Feb-13	0	0	0.00	0	0	0.00	476	61	128.15
4	Smith	Oil	Mar-13	0	0	0.00	0	0	0.00	476	61	128.15
5	Smith	Oil	Apr-13	0	0	0.00	0	0	0.00	476	61	128.15
6	Smith	Oil	May-13	0	0	0.00	0	0	0.00	476	61	128.15
7	Smith	Oil	Jun-13	0	0	0.00	0	0	0.00	476	61	128.15
8	Smith	Oil	Jul-13	0	0	0.00	0	0	0.00	476	61	128.15
9	Smith	Oil	Aug-13	0	0	0.00	0	0	0.00	476	61	128.15
10	Smith	Oil	Sep-13	0	0	0.00	0	0	0.00	476	61	128.15
11	Smith	Oil	Oct-13	0	0	0.00	0	0	0.00	476	61	128.15
12	Smith	Oil	Nov-13	0	0	0.00	0	0	0.00	476	61	128.15
13	Smith	Oil	Dec-13	0	0	0.00	0	0	0.00	476	61	128.15
14	Total									6,169	793	
15	Smith	Oil	13 mth avg							475	61	128.42

16 Totals may not add due to rounding.

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide conventional fuel account balances in dollars and quantities for each fuel type for the test year and the two preceeding years. Include Natural Gas even though no inventory is carried. (Give units in Barrels, Tons, or MCF)

Type of Data Shown:
____ Projected Test Year Ended 12/31/14
X Prior Year Ended 12/31/13
____ Historical Year Ended 12/31/12

Witness: M. L. Burroughs, S. D. Ritenour

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
				Beginning Inventory			Receipts			Fuel Issued to Generation		
Line No.	Plant	Fuel Type	Month	Units	($000)	$/Unit	Units	($000)	$/Unit	Units	($000)	$/Unit
1	Scholz	Oil	Dec-12	263	34	129.28	0	0	0.00	2	0	0.00
2	Scholz	Oil	Jan-13	261	34	130.27	100	12	120.00	4	0	0.00
3	Scholz	Oil	Feb-13	357	46	128.85	2	0	0.00	2	0	0.00
4	Scholz	Oil	Mar-13	357	46	128.85	0	0	0.00	0	0	0.00
5	Scholz	Oil	Apr-13	357	46	128.85	0	0	0.00	0	0	0.00
6	Scholz	Oil	May-13	357	46	128.85	0	0	0.00	0	0	0.00
7	Scholz	Oil	Jun-13	357	46	128.85	4	0	0.00	4	0	0.00
8	Scholz	Oil	Jul-13	357	46	128.85	4	0	0.00	4	0	0.00
9	Scholz	Oil	Aug-13	357	46	128.85	4	0	0.00	4	0	0.00
10	Scholz	Oil	Sep-13	357	46	128.85	0	0	0.00	0	0	0.00
11	Scholz	Oil	Oct-13	357	46	128.85	0	0	0.00	0	0	0.00
12	Scholz	Oil	Nov-13	357	46	128.85	0	0	0.00	0	0	0.00
13	Scholz	Oil	Dec-13	357	46	128.85	2	0	0.00	2	0	0.00

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide conventional fuel account balances in dollars and quantities for each fuel type for the test year and the two preceeding years. Include Natural Gas even though no inventory is carried. (Give units in Barrels, Tons, or MCF)

Type of Data Shown:

_____ Projected Test Year Ended 12/31/14

__X__ Prior Year Ended 12/31/13

_____ Historical Year Ended 12/31/12

Witness: M. L. Burroughs, S. D. Ritenour

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
				Fuel Issues (Other)			Adjustments			Ending Inventory		
Line No.	Plant	Fuel Type	Month	Units	($000)	$/Unit	Units	($000)	$/Unit	Units	($000)	$/Unit
1	Scholz	Oil	Dec-12	0	0	0.00	0	0	0.00	261	34	130.27
2	Scholz	Oil	Jan-13	0	0	0.00	0	0	0.00	357	46	128.85
3	Scholz	Oil	Feb-13	0	0	0.00	0	0	0.00	357	46	128.85
4	Scholz	Oil	Mar-13	0	0	0.00	0	0	0.00	357	46	128.85
5	Scholz	Oil	Apr-13	0	0	0.00	0	0	0.00	357	46	128.85
6	Scholz	Oil	May-13	0	0	0.00	0	0	0.00	357	46	128.85
7	Scholz	Oil	Jun-13	0	0	0.00	0	0	0.00	357	46	128.85
8	Scholz	Oil	Jul-13	0	0	0.00	0	0	0.00	357	46	128.85
9	Scholz	Oil	Aug-13	0	0	0.00	0	0	0.00	357	46	128.85
10	Scholz	Oil	Sep-13	0	0	0.00	0	0	0.00	357	46	128.85
11	Scholz	Oil	Oct-13	0	0	0.00	0	0	0.00	357	46	128.85
12	Scholz	Oil	Nov-13	0	0	0.00	0	0	0.00	357	46	128.85
13	Scholz	Oil	Dec-13	0	0	0.00	0	0	0.00	357	46	128.85
14	Total									4,545	586	
15	Scholz	Oil	13 mth avg							350	45	128.57

16 Totals may not add due to rounding.

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide conventional fuel account balances in dollars and quantities for each fuel type for the test year and the two preceeding years. Include Natural Gas even though no inventory is carried. (Give units in Barrels, Tons, or MCF)

Type of Data Shown:

____ Projected Test Year Ended 12/31/14

X Prior Year Ended 12/31/13

____ Historical Year Ended 12/31/12

Witness: M. L. Burroughs, S. D. Ritenour

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
				Beginning Inventory			Receipts			Fuel Issued to Generation		
Line No.	Plant	Fuel Type	Month	Units	($000)	$/Unit	Units	($000)	$/Unit	Units	($000)	$/Unit
1	Daniel	Oil	Dec-12	2,598	357	137.41	0	0	0.00	0	0	0.00
2	Daniel	Oil	Jan-13	2,598	357	137.41	317	78	246.06	511	76	148.73
3	Daniel	Oil	Feb-13	2,404	359	149.33	235	30	127.66	235	35	148.94
4	Daniel	Oil	Mar-13	2,404	354	147.25	0	0	0.00	0	0	0.00
5	Daniel	Oil	Apr-13	2,404	354	147.25	0	0	0.00	0	0	0.00
6	Daniel	Oil	May-13	2,404	354	147.25	0	0	0.00	0	0	0.00
7	Daniel	Oil	Jun-13	2,404	354	147.25	511	66	129.16	511	74	144.81
8	Daniel	Oil	Jul-13	2,404	346	143.93	511	65	127.20	511	72	140.90
9	Daniel	Oil	Aug-13	2,404	339	141.01	511	65	127.20	511	71	138.94
10	Daniel	Oil	Sep-13	2,404	333	138.52	511	66	129.16	511	70	136.99
11	Daniel	Oil	Oct-13	2,404	329	136.86	276	34	123.19	276	37	134.06
12	Daniel	Oil	Nov-13	2,404	326	135.61	511	66	129.16	511	69	135.03
13	Daniel	Oil	Dec-13	2,404	323	134.36	276	35	126.81	276	37	134.06

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide conventional fuel account balances in dollars and quantities for each fuel type for the test year and the two preceeding years. Include Natural Gas even though no inventory is carried. (Give units in Barrels, Tons, or MCF)

Type of Data Shown:
____ Projected Test Year Ended 12/31/14
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____ Historical Year Ended 12/31/12

Witness: M. L. Burroughs, S. D. Ritenour

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
				Fuel Issues (Other)			Adjustments			Ending Inventory		
Line No.	Plant	Fuel Type	Month	Units	($000)	$/Unit	Units	($000)	$/Unit	Units	($000)	$/Unit
1	Daniel	Oil	Dec-12	0	0	0.00	0	0	0.00	2,598	357	137.41
2	Daniel	Oil	Jan-13	0	0	0.00	0	0	0.00	2,404	359	149.33
3	Daniel	Oil	Feb-13	0	0	0.00	0	0	0.00	2,404	354	147.25
4	Daniel	Oil	Mar-13	0	0	0.00	0	0	0.00	2,404	354	147.25
5	Daniel	Oil	Apr-13	0	0	0.00	0	0	0.00	2,404	354	147.25
6	Daniel	Oil	May-13	0	0	0.00	0	0	0.00	2,404	354	147.25
7	Daniel	Oil	Jun-13	0	0	0.00	0	0	0.00	2,404	346	143.93
8	Daniel	Oil	Jul-13	0	0	0.00	0	0	0.00	2,404	339	141.01
9	Daniel	Oil	Aug-13	0	0	0.00	0	0	0.00	2,404	333	138.52
10	Daniel	Oil	Sep-13	0	0	0.00	0	0	0.00	2,404	329	136.86
11	Daniel	Oil	Oct-13	0	0	0.00	0	0	0.00	2,404	326	135.61
12	Daniel	Oil	Nov-13	0	0	0.00	0	0	0.00	2,404	323	134.36
13	Daniel	Oil	Dec-13	0	0	0.00	0	0	0.00	2,404	321	133.53
14	Total									31,446	4,449	
15	Daniel	Oil	13 mth avg							2,419	342	141.38

16 Totals may not add due to rounding.

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide conventional fuel account balances in dollars and quantities for each fuel type for the test year and the two preceeding years. Include Natural Gas even though no inventory is carried. (Give units in Barrels, Tons, or MCF)

Type of Data Shown:

_____ Projected Test Year Ended 12/31/14

__X__ Prior Year Ended 12/31/13

_____ Historical Year Ended 12/31/12

Witness: M. L. Burroughs, S. D. Ritenour

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
				Beginning Inventory			Receipts			Fuel Issued to Generation		
Line No.	Plant	Fuel Type	Month	Units	($000)	$/Unit	Units	($000)	$/Unit	Units	($000)	$/Unit
1	Scherer	Oil	Dec-12	1,338	185	138.27	100	14	140.00	26	4	153.85
2	Scherer	Oil	Jan-13	1,246	172	138.04	-48	5	-104.17	141	21	148.94
3	Scherer	Oil	Feb-13	1,057	156	147.59	1	0	0.00	141	21	148.94
4	Scherer	Oil	Mar-13	917	135	147.22	0	0	0.00	0	0	0.00
5	Scherer	Oil	Apr-13	917	135	147.22	69	10	144.93	141	21	148.94
6	Scherer	Oil	May-13	845	124	146.75	141	18	127.66	141	20	141.84
7	Scherer	Oil	Jun-13	845	122	144.38	141	19	134.75	141	20	141.84
8	Scherer	Oil	Jul-13	845	121	143.20	141	19	134.75	141	20	141.84
9	Scherer	Oil	Aug-13	845	120	142.01	141	19	134.75	141	20	141.84
10	Scherer	Oil	Sep-13	845	119	140.83	141	20	141.84	141	20	141.84
11	Scherer	Oil	Oct-13	845	119	140.83	141	19	134.75	141	20	141.84
12	Scherer	Oil	Nov-13	845	118	139.64	141	19	134.75	141	20	141.84
13	Scherer	Oil	Dec-13	845	117	138.46	141	19	134.75	141	19	134.75

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

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EXPLANATION: Provide conventional fuel account balances in dollars and quantities for each fuel type for the test year and the two preceeding years. Include Natural Gas even though no inventory is carried. (Give units in Barrels, Tons, or MCF)

Type of Data Shown:

____ Projected Test Year Ended 12/31/14

X Prior Year Ended 12/31/13

____ Historical Year Ended 12/31/12

Witness: M. L. Burroughs, S. D. Ritenour

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
				Fuel Issues (Other)			Adjustments			Ending Inventory		
Line No.	Plant	Fuel Type	Month	Units	($000)	$/Unit	Units	($000)	$/Unit	Units	($000)	$/Unit
1	Scherer	Oil	Dec-12	0	0	0.00	-167	-23	137.72	1,246	172	138.04
2	Scherer	Oil	Jan-13	0	0	0.00	0	0	0.00	1,057	156	147.59
3	Scherer	Oil	Feb-13	0	0	0.00	0	0	0.00	917	135	147.22
4	Scherer	Oil	Mar-13	0	0	0.00	0	0	0.00	917	135	147.22
5	Scherer	Oil	Apr-13	0	0	0.00	0	0	0.00	845	124	146.75
6	Scherer	Oil	May-13	0	0	0.00	0	0	0.00	845	122	144.38
7	Scherer	Oil	Jun-13	0	0	0.00	0	0	0.00	845	121	143.20
8	Scherer	Oil	Jul-13	0	0	0.00	0	0	0.00	845	120	142.01
9	Scherer	Oil	Aug-13	0	0	0.00	0	0	0.00	845	119	140.83
10	Scherer	Oil	Sep-13	0	0	0.00	0	0	0.00	845	119	140.83
11	Scherer	Oil	Oct-13	0	0	0.00	0	0	0.00	845	118	139.64
12	Scherer	Oil	Nov-13	0	0	0.00	0	0	0.00	845	117	138.46
13	Scherer	Oil	Dec-13	0	0	0.00	0	0	0.00	845	117	138.46
14	Total									11,742	1,675	
15	Scherer	Oil	13 mth avg							903	129	142.86

16 Totals may not add due to rounding.

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide conventional fuel account balances in dollars and quantities for each fuel type for the test year and the two preceeding years. Include Natural Gas even though no inventory is carried. (Give units in Barrels, Tons, or MCF)

Type of Data Shown:
____ Projected Test Year Ended 12/31/14
X Prior Year Ended 12/31/13
____ Historical Year Ended 12/31/12

Witness: M. L. Burroughs, S. D. Ritenour

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
				Beginning Inventory			Receipts			Fuel Issued to Generation		
Line No.	Plant	Fuel Type	Month	Units	($000)	$/Unit	Units	($000)	$/Unit	Units	($000)	$/Unit
1	Smith	Nat. Gas	Dec-12	661,906	2,867	4.33	2,311,592	9,183	3.97	2,203,866	8,931	4.05
2	Smith	Nat. Gas	Jan-13	769,632	3,120	4.05	2,387,420	10,798	4.52	2,428,533	10,970	4.52
3	Smith	Nat. Gas	Feb-13	728,519	2,948	4.05	2,288,570	10,422	4.55	2,288,570	10,414	4.55
4	Smith	Nat. Gas	Mar-13	728,519	2,956	4.06	1,659,470	7,653	4.61	1,659,470	7,676	4.63
5	Smith	Nat. Gas	Apr-13	728,519	2,933	4.03	1,709,589	9,163	5.36	1,772,938	9,432	5.32
6	Smith	Nat. Gas	May-13	665,170	2,664	4.00	2,477,313	12,418	5.01	2,445,638	12,269	5.02
7	Smith	Nat. Gas	Jun-13	696,845	2,813	4.04	2,593,597	13,064	5.04	2,340,199	12,011	5.13
8	Smith	Nat. Gas	Jul-13	950,243	3,866	4.07	2,450,680	12,703	5.18	2,450,680	12,654	5.16
9	Smith	Nat. Gas	Aug-13	950,243	3,915	4.12	2,456,718	12,716	5.18	2,456,718	12,706	5.17
10	Smith	Nat. Gas	Sep-13	950,243	3,925	4.13	2,268,515	11,893	5.24	2,300,190	12,014	5.22
11	Smith	Nat. Gas	Oct-13	918,568	3,804	4.14	2,415,643	12,483	5.17	2,447,318	12,587	5.14
12	Smith	Nat. Gas	Nov-13	886,893	3,700	4.17	2,227,180	10,687	4.80	2,227,180	10,585	4.75
13	Smith	Nat. Gas	Dec-13	886,893	3,802	4.29	1,603,134	8,437	5.26	1,761,508	8,972	5.09

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide conventional fuel account balances in dollars and quantities for each fuel type for the test year and the two preceeding years. Include Natural Gas even though no inventory is carried. (Give units in Barrels, Tons, or MCF)

Type of Data Shown:

_____ Projected Test Year Ended 12/31/14

X Prior Year Ended 12/31/13

_____ Historical Year Ended 12/31/12

Witness: M. L. Burroughs, S. D. Ritenour

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
				Fuel Issues (Other)			Adjustments			Ending Inventory		
Line No.	Plant	Fuel Type	Month	Units	($000)	$/Unit	Units	($000)	$/Unit	Units	($000)	$/Unit
1	Smith	Nat. Gas	Dec-12	0	0	0.00	0	0	0.00	769,632	3,120	4.05
2	Smith	Nat. Gas	Jan-13	0	0	0.00	0	0	0.00	728,519	2,948	4.05
3	Smith	Nat. Gas	Feb-13	0	0	0.00	0	0	0.00	728,519	2,956	4.06
4	Smith	Nat. Gas	Mar-13	0	0	0.00	0	0	0.00	728,519	2,933	4.03
5	Smith	Nat. Gas	Apr-13	0	0	0.00	0	0	0.00	665,170	2,664	4.00
6	Smith	Nat. Gas	May-13	0	0	0.00	0	0	0.00	696,845	2,813	4.04
7	Smith	Nat. Gas	Jun-13	0	0	0.00	0	0	0.00	950,243	3,866	4.07
8	Smith	Nat. Gas	Jul-13	0	0	0.00	0	0	0.00	950,243	3,915	4.12
9	Smith	Nat. Gas	Aug-13	0	0	0.00	0	0	0.00	950,243	3,925	4.13
10	Smith	Nat. Gas	Sep-13	0	0	0.00	0	0	0.00	918,568	3,804	4.14
11	Smith	Nat. Gas	Oct-13	0	0	0.00	0	0	0.00	886,893	3,700	4.17
12	Smith	Nat. Gas	Nov-13	0	0	0.00	0	0	0.00	886,893	3,802	4.29
13	Smith	Nat. Gas	Dec-13	0	0	0.00	0	0	0.00	728,519	3,267	4.48
14	Total									10,588,806	43,713	
15	Smith	Nat. Gas	13 mth avg							814,524	3,363	4.13

16 Totals may not add due to rounding.

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide conventional fuel account balances in dollars and quantities for each fuel type for the test year and the two preceeding years. Include Natural Gas even though no inventory is carried. (Give units in Barrels, Tons, or MCF)

Type of Data Shown:
____ Projected Test Year Ended 12/31/14
_X_ Prior Year Ended 12/31/13
____ Historical Year Ended 12/31/12

Witness: M. L. Burroughs, S. D. Ritenour

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
				Beginning Inventory			Receipts			Fuel Issued to Generation		
Line No.	Plant	Fuel Type	Month	Units	($000)	$/Unit	Units	($000)	$/Unit	Units	($000)	$/Unit
1	Crist	Nat. Gas	Dec-12	0	0	0.00	139,646	581	4.16	139,646	581	4.16
2	Crist	Nat. Gas	Jan-13	0	0	0.00	38,836	268	6.90	38,836	268	6.90
3	Crist	Nat. Gas	Feb-13	0	0	0.00	38,836	269	6.93	38,836	269	6.93
4	Crist	Nat. Gas	Mar-13	0	0	0.00	38,836	268	6.90	38,836	268	6.90
5	Crist	Nat. Gas	Apr-13	0	0	0.00	38,836	267	6.88	38,836	267	6.88
6	Crist	Nat. Gas	May-13	0	0	0.00	38,836	268	6.90	38,836	268	6.90
7	Crist	Nat. Gas	Jun-13	0	0	0.00	38,836	269	6.93	38,836	269	6.93
8	Crist	Nat. Gas	Jul-13	0	0	0.00	38,836	271	6.98	38,836	271	6.98
9	Crist	Nat. Gas	Aug-13	0	0	0.00	38,836	272	7.00	38,836	272	7.00
10	Crist	Nat. Gas	Sep-13	0	0	0.00	38,836	272	7.00	38,836	272	7.00
11	Crist	Nat. Gas	Oct-13	0	0	0.00	29,127	233	8.00	29,127	233	8.00
12	Crist	Nat. Gas	Nov-13	0	0	0.00	38,836	278	7.16	38,836	278	7.16
13	Crist	Nat. Gas	Dec-13	0	0	0.00	38,836	288	7.36	38,836	286	7.36

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide conventional fuel account balances in dollars and quantities for each fuel type for the test year and the two preceeding years. Include Natural Gas even though no inventory is carried. (Give units in Barrels, Tons, or MCF)

Type of Data Shown:

____ Projected Test Year Ended 12/31/14

_X_ Prior Year Ended 12/31/13

____ Historical Year Ended 12/31/12

Witness: M. L. Burroughs, S. D. Ritenour

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
				Fuel Issues (Other)			Adjustments			Ending Inventory		
Line No.	Plant	Fuel Type	Month	Units	($000)	$/Unit	Units	($000)	$/Unit	Units	($000)	$/Unit
1	Crist	Nat. Gas	Dec-12	0	0	0.00	0	0	0.00	0	0	0.00
2	Crist	Nat. Gas	Jan-13	0	0	0.00	0	0	0.00	0	0	0.00
3	Crist	Nat. Gas	Feb-13	0	0	0.00	0	0	0.00	0	0	0.00
4	Crist	Nat. Gas	Mar-13	0	0	0.00	0	0	0.00	0	0	0.00
5	Crist	Nat. Gas	Apr-13	0	0	0.00	0	0	0.00	0	0	0.00
6	Crist	Nat. Gas	May-13	0	0	0.00	0	0	0.00	0	0	0.00
7	Crist	Nat. Gas	Jun-13	0	0	0.00	0	0	0.00	0	0	0.00
8	Crist	Nat. Gas	Jul-13	0	0	0.00	0	0	0.00	0	0	0.00
9	Crist	Nat. Gas	Aug-13	0	0	0.00	0	0	0.00	0	0	0.00
10	Crist	Nat. Gas	Sep-13	0	0	0.00	0	0	0.00	0	0	0.00
11	Crist	Nat. Gas	Oct-13	0	0	0.00	0	0	0.00	0	0	0.00
12	Crist	Nat. Gas	Nov-13	0	0	0.00	0	0	0.00	0	0	0.00
13	Crist	Nat. Gas	Dec-13	0	0	0.00	0	0	0.00	0	0	0.00
14	Total									0	0	
15	Crist	Nat. Gas	13 mth avg							0	0	0.00

16 Totals may not add due to rounding.

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide conventional fuel account balances in dollars and quantities for each fuel type for the test year and the two preceeding years. Include Natural Gas even though no inventory is carried. (Give units in Barrels, Tons, or MCF)

Type of Data Shown:
____ Projected Test Year Ended 12/31/14
X Prior Year Ended 12/31/13
____ Historical Year Ended 12/31/12

Witness: M. L. Burroughs, S. D. Ritenour

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
				Beginning Inventory			Receipts			Fuel Issued to Generation		
Line No.	Plant	Fuel Type	Month	Units	($000)	$/Unit	Units	($000)	$/Unit	Units	($000)	$/Unit
1	Baconton	Nat. Gas	Dec-12	0	0	0.00	81,062	310	3.82	81,062	310	3.82
2	Baconton	Nat. Gas	Jan-13	0	0	0.00	20,022	94	4.69	20,022	94	4.69
3	Baconton	Nat. Gas	Feb-13	0	0	0.00	0	0	0.00	0	0	0.00
4	Baconton	Nat. Gas	Mar-13	0	0	0.00	8,416	39	4.63	8,416	39	4.63
5	Baconton	Nat. Gas	Apr-13	0	0	0.00	0	0	0.00	0	0	0.00
6	Baconton	Nat. Gas	May-13	0	0	0.00	179,998	915	5.08	179,998	915	5.08
7	Baconton	Nat. Gas	Jun-13	0	0	0.00	264,693	1,322	4.99	264,693	1,322	4.99
8	Baconton	Nat. Gas	Jul-13	0	0	0.00	349,669	1,741	4.98	349,669	1,741	4.98
9	Baconton	Nat. Gas	Aug-13	0	0	0.00	322,236	1,614	5.01	322,236	1,614	5.01
10	Baconton	Nat. Gas	Sep-13	0	0	0.00	152,508	806	5.28	152,508	806	5.28
11	Baconton	Nat. Gas	Oct-13	0	0	0.00	42,748	205	4.80	42,748	205	4.80
12	Baconton	Nat. Gas	Nov-13	0	0	0.00	0	0	0.00	0	0	0.00
13	Baconton	Nat. Gas	Dec-13	0	0	0.00	0	0	0.00	0	0	0.00

14 Note: Gulf provides the fuel to operate these units per the Purchase Power Agreement.

Supporting Schedules: Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide conventional fuel account balances in dollars and quantities for each fuel type for the test year and the two preceeding years. Include Natural Gas even though no Inventory is carried. (Give units in Barrels, Tons, or MCF)

Type of Data Shown:
____ Projected Test Year Ended 12/31/14
X Prior Year Ended 12/31/13
____ Historical Year Ended 12/31/12
Witness: M. L. Burroughs, S. D. Ritenour

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
				Fuel Issues (Other)			Adjustments			Ending Inventory		
Line No.	Plant	Fuel Type	Month	Units	($000)	$/Unit	Units	($000)	$/Unit	Units	($000)	$/Unit
1	Baconton	Nat. Gas	Dec-12	0	0	0.00	0	0	0.00	0	0	0.00
2	Baconton	Nat. Gas	Jan-13	0	0	0.00	0	0	0.00	0	0	0.00
3	Baconton	Nat. Gas	Feb-13	0	0	0.00	0	0	0.00	0	0	0.00
4	Baconton	Nat. Gas	Mar-13	0	0	0.00	0	0	0.00	0	0	0.00
5	Baconton	Nat. Gas	Apr-13	0	0	0.00	0	0	0.00	0	0	0.00
6	Baconton	Nat. Gas	May-13	0	0	0.00	0	0	0.00	0	0	0.00
7	Baconton	Nat. Gas	Jun-13	0	0	0.00	0	0	0.00	0	0	0.00
8	Baconton	Nat. Gas	Jul-13	0	0	0.00	0	0	0.00	0	0	0.00
9	Baconton	Nat. Gas	Aug-13	0	0	0.00	0	0	0.00	0	0	0.00
10	Baconton	Nat. Gas	Sep-13	0	0	0.00	0	0	0.00	0	0	0.00
11	Baconton	Nat. Gas	Oct-13	0	0	0.00	0	0	0.00	0	0	0.00
12	Baconton	Nat. Gas	Nov-13	0	0	0.00	0	0	0.00	0	0	0.00
13	Baconton	Nat. Gas	Dec-13	0	0	0.00	0	0	0.00	0	0	0.00
14	Total									0	0	
15	Baconton	Nat. Gas	13 mth avg							0	0	0.00

16 Note: Gulf provides the fuel to operate these units per the Purchase Power Agreement.
17 Totals may not add due to rounding.

Supporting Schedules: Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide conventional fuel account balances in dollars and quantities for each fuel type for the test year and the two preceeding years. Include Natural Gas even though no inventory is carried. (Give units in Barrels, Tons, or MCF)

Type of Data Shown:

_____ Projected Test Year Ended 12/31/14

X Prior Year Ended 12/31/13

_____ Historical Year Ended 12/31/12

Witness: M. L. Burroughs, S. D. Ritenour

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
				Beginning Inventory			Receipts			Fuel Issued to Generation		
Line No.	Plant	Fuel Type	Month	Units	($000)	$/Unit	Units	($000)	$/Unit	Units	($000)	$/Unit
1	Dahlberg	Nat. Gas	Dec-12	0	0	0.00	410	1	2.44	410	1	2.44
2	Dahlberg	Nat. Gas	Jan-13	0	0	0.00	0	0	0.00	0	0	0.00
3	Dahlberg	Nat. Gas	Feb-13	0	0	0.00	0	0	0.00	0	0	0.00
4	Dahlberg	Nat. Gas	Mar-13	0	0	0.00	0	0	0.00	0	0	0.00
5	Dahlberg	Nat. Gas	Apr-13	0	0	0.00	0	0	0.00	0	0	0.00
6	Dahlberg	Nat. Gas	May-13	0	0	0.00	68,395	388	5.67	68,395	388	5.67
7	Dahlberg	Nat. Gas	Jun-13	0	0	0.00	201,257	975	4.84	201,257	975	4.84
8	Dahlberg	Nat. Gas	Jul-13	0	0	0.00	240,790	1,161	4.82	240,790	1,161	4.82
9	Dahlberg	Nat. Gas	Aug-13	0	0	0.00	144,134	733	5.09	144,134	733	5.09
10	Dahlberg	Nat. Gas	Sep-13	0	0	0.00	127,423	658	5.16	127,423	658	5.16
11	Dahlberg	Nat. Gas	Oct-13	0	0	0.00	0	0	0.00	0	0	0.00
12	Dahlberg	Nat. Gas	Nov-13	0	0	0.00	0	0	0.00	0	0	0.00
13	Dahlberg	Nat. Gas	Dec-13	0	0	0.00	0	0	0.00	0	0	0.00

14 Note: Gulf provides the fuel to operate these units per the Purchase Power Agreement.

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide conventional fuel account balances in dollars and quantities for each fuel type for the test year and the two preceeding years. Include Natural Gas even though no inventory is carried. (Give units in Barrels, Tons, or MCF)

Type of Data Shown:
___ Projected Test Year Ended 12/31/14
X Prior Year Ended 12/31/13
___ Historical Year Ended 12/31/12

Witness: M. L. Burroughs, S. D. Ritenour

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
				Fuel Issues (Other)			Adjustments			Ending Inventory		
Line No.	Plant	Fuel Type	Month	Units	($000)	$/Unit	Units	($000)	$/Unit	Units	($000)	$/Unit
1	Dahlberg	Nat. Gas	Dec-12	0	0	0.00	0	0	0.00	0	0	0.00
2	Dahlberg	Nat. Gas	Jan-13	0	0	0.00	0	0	0.00	0	0	0.00
3	Dahlberg	Nat. Gas	Feb-13	0	0	0.00	0	0	0.00	0	0	0.00
4	Dahlberg	Nat. Gas	Mar-13	0	0	0.00	0	0	0.00	0	0	0.00
5	Dahlberg	Nat. Gas	Apr-13	0	0	0.00	0	0	0.00	0	0	0.00
6	Dahlberg	Nat. Gas	May-13	0	0	0.00	0	0	0.00	0	0	0.00
7	Dahlberg	Nat. Gas	Jun-13	0	0	0.00	0	0	0.00	0	0	0.00
8	Dahlberg	Nat. Gas	Jul-13	0	0	0.00	0	0	0.00	0	0	0.00
9	Dahlberg	Nat. Gas	Aug-13	0	0	0.00	0	0	0.00	0	0	0.00
10	Dahlberg	Nat. Gas	Sep-13	0	0	0.00	0	0	0.00	0	0	0.00
11	Dahlberg	Nat. Gas	Oct-13	0	0	0.00	0	0	0.00	0	0	0.00
12	Dahlberg	Nat. Gas	Nov-13	0	0	0.00	0	0	0.00	0	0	0.00
13	Dahlberg	Nat. Gas	Dec-13	0	0	0.00	0	0	0.00	0	0	0.00
14	Total									0	0	
15	Dahlberg	Nat. Gas	13 mth avg							0	0	0.00

16 Note: Gulf provides the fuel to operate these units per the Purchase Power Agreement.
17 Totals may not add due to rounding.

Supporting Schedules: Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide conventional fuel account balances in dollars and quantities for each fuel type for the test year and the two preceeding years. Include Natural Gas even though no inventory is carried. (Give units in Barrels, Tons, or MCF)

Type of Data Shown:

____ Projected Test Year Ended 12/31/14

X Prior Year Ended 12/31/13

____ Historical Year Ended 12/31/12

Witness: M. L. Burroughs, S. D. Ritenour

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
				Beginning Inventory			Receipts			Fuel Issued to Generation		
Line No.	Plant	Fuel Type	Month	Units	($000)	$/Unit	Units	($000)	$/Unit	Units	($000)	$/Unit
1	Cent. AL	Nat. Gas	Dec-12	0	0	0.00	3,901,194	15,171	3.89	3,901,194	15,171	3.89
2	Cent. AL	Nat. Gas	Jan-13	0	0	0.00	2,364,512	10,499	4.44	2,364,512	10,499	4.44
3	Cent. AL	Nat. Gas	Feb-13	0	0	0.00	2,057,434	9,136	4.44	2,057,434	9,136	4.44
4	Cent. AL	Nat. Gas	Mar-13	0	0	0.00	766,194	3,362	4.39	766,194	3,362	4.39
5	Cent. AL	Nat. Gas	Apr-13	0	0	0.00	1,411,966	6,173	4.37	749,345	3,519	4.70
6	Cent. AL	Nat. Gas	May-13	662,621	2,654	4.01	1,797,353	8,161	4.54	1,765,799	8,013	4.54
7	Cent. AL	Nat. Gas	Jun-13	694,175	2,802	4.04	3,754,318	16,581	4.42	3,501,891	15,532	4.44
8	Cent. AL	Nat. Gas	Jul-13	946,602	3,851	4.07	3,899,443	17,395	4.46	3,899,443	17,346	4.45
9	Cent. AL	Nat. Gas	Aug-13	946,602	3,900	4.12	3,935,921	17,547	4.46	3,935,921	17,537	4.46
10	Cent. AL	Nat. Gas	Sep-13	946,602	3,910	4.13	3,615,060	16,188	4.48	3,646,613	16,309	4.47
11	Cent. AL	Nat. Gas	Oct-13	915,049	3,789	4.14	1,276,842	6,658	5.21	1,308,396	6,761	5.17
12	Cent. AL	Nat. Gas	Nov-13	883,495	3,686	4.17	2,380,796	11,617	4.88	2,380,796	11,516	4.84
13	Cent. AL	Nat. Gas	Dec-13	883,495	3,787	4.29	3,315,036	16,407	4.95	3,472,803	16,940	4.88

14 Note: Gulf provides the fuel to operate these units per the Purchase Power Agreement.

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide conventional fuel account balances in dollars and quantities for each fuel type for the test year and the two preceeding years. Include Natural Gas even though no inventory is carried. (Give units in Barrels, Tons, or MCF)

Type of Data Shown:
____ Projected Test Year Ended 12/31/14
X Prior Year Ended 12/31/13
____ Historical Year Ended 12/31/12
Witness: M. L. Burroughs, S. D. Ritenour

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
				Fuel Issues (Other)			Adjustments			Ending Inventory		
Line No.	Plant	Fuel Type	Month	Units	($000)	$/Unit	Units	($000)	$/Unit	Units	($000)	$/Unit
1	Cent. AL	Nat. Gas	Dec-12	0	0	0.00	0	0	0.00	0	0	0.00
2	Cent. AL	Nat. Gas	Jan-13	0	0	0.00	0	0	0.00	0	0	0.00
3	Cent. AL	Nat. Gas	Feb-13	0	0	0.00	0	0	0.00	0	0	0.00
4	Cent. AL	Nat. Gas	Mar-13	0	0	0.00	0	0	0.00	0	0	0.00
5	Cent. AL	Nat. Gas	Apr-13	0	0	0.00	0	0	0.00	662,621	2,654	4.01
6	Cent. AL	Nat. Gas	May-13	0	0	0.00	0	0	0.00	694,175	2,802	4.04
7	Cent. AL	Nat. Gas	Jun-13	0	0	0.00	0	0	0.00	946,602	3,851	4.07
8	Cent. AL	Nat. Gas	Jul-13	0	0	0.00	0	0	0.00	946,602	3,900	4.12
9	Cent. AL	Nat. Gas	Aug-13	0	0	0.00	0	0	0.00	946,602	3,910	4.13
10	Cent. AL	Nat. Gas	Sep-13	0	0	0.00	0	0	0.00	915,049	3,789	4.14
11	Cent. AL	Nat. Gas	Oct-13	0	0	0.00	0	0	0.00	883,495	3,686	4.17
12	Cent. AL	Nat. Gas	Nov-13	0	0	0.00	0	0	0.00	883,495	3,787	4.29
13	Cent. AL	Nat. Gas	Dec-13	0	0	0.00	0	0	0.00	725,728	3,254	4.48
14	Total									7,604,369	31,633	
15	Cent. AL	Nat. Gas	13 mth avg							584,951	2,433	4.16

16 Note: Gulf provides the fuel to operate these units per the Purchase Power Agreement.
17 Totals may not add due to rounding.

Supporting Schedules: Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide conventional fuel account balances in dollars and quantities for each fuel type for the test year and the two preceeding years. Include Natural Gas even though no inventory is carried. (Give units in Barrels, Tons, or MCF)

Type of Data Shown:

_____ Projected Test Year Ended 12/31/14

_____ Prior Year Ended 12/31/13

X Historical Year Ended 12/31/12

Witness: M. L. Burroughs, S. D. Ritenour

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
				Beginning Inventory			Receipts			Fuel Issued to Generation		
Line No.	Plant	Fuel Type	Month	Units	($000)	$/Unit	Units	($000)	$/Unit	Units	($000)	$/Unit
1	Crist	Coal (tons)	Dec-11	256,440	28,436	110.89	94,813	12,306	129.79	91,972	10,668	115.99
2	Crist	Coal (tons)	Jan-12	259,280	30,074	115.99	102,137	11,924	116.75	91,404	10,621	116.20
3	Crist	Coal (tons)	Feb-12	270,013	31,376	116.20	78,684	6,838	86.90	78,111	8,560	109.59
4	Crist	Coal (tons)	Mar-12	270,586	29,654	109.59	78,371	8,211	104.77	84,664	9,148	108.05
5	Crist	Coal (tons)	Apr-12	269,071	29,072	108.05	97,039	9,477	97.66	87,982	9,264	105.29
6	Crist	Coal (tons)	May-12	278,128	29,284	105.29	130,696	14,023	107.29	132,672	14,054	105.93
7	Crist	Coal (tons)	Jun-12	276,152	29,253	105.93	137,560	18,888	137.31	143,251	17,150	119.72
8	Crist	Coal (tons)	Jul-12	270,461	30,992	114.59	108,238	9,269	85.64	109,271	11,149	102.03
9	Crist	Coal (tons)	Aug-12	269,428	29,112	108.05	103,448	10,419	100.72	125,307	13,285	106.02
10	Crist	Coal (tons)	Sep-12	247,580	26,247	106.01	92,890	8,090	87.09	77,192	7,791	100.93
11	Crist	Coal (tons)	Oct-12	268,093	27,057	100.92	80,306	8,190	101.98	75,985	7,687	101.16
12	Crist	Coal (tons)	Nov-12	272,414	27,560	101.17	69,898	7,591	108.60	59,738	6,134	102.68
13	Crist	Coal (tons)	Dec-12	282,573	29,016	102.68	90,154	8,939	99.15	94,997	9,673	101.82

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide conventional fuel account balances in dollars and quantities for each fuel type for the test year and the two preceeding years. Include Natural Gas even though no inventory is carried. (Give units in Barrels, Tons, or MCF)

Type of Data Shown:
____ Projected Test Year Ended 12/31/14
____ Prior Year Ended 12/31/13
X Historical Year Ended 12/31/12
Witness: M. L. Burroughs, S. D. Ritenour

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
				Fuel Issues (Other)			Adjustments			Ending Inventory		
Line No.	Plant	Fuel Type	Month	Units	($000)	$/Unit	Units	($000)	$/Unit	Units	($000)	$/Unit
1	Crist	Coal (tons)	Dec-11	0	0	0.00	0	0	0.00	259,280	30,074	115.99
2	Crist	Coal (tons)	Jan-12	0	0	0.00	0	0	0.00	270,013	31,376	116.20
3	Crist	Coal (tons)	Feb-12	0	0	0.00	0	0	0.00	270,586	29,654	109.59
4	Crist	Coal (tons)	Mar-12	0	0	0.00	4,778	354	74.09	269,071	29,072	108.05
5	Crist	Coal (tons)	Apr-12	0	0	0.00	0	0	0.00	278,128	29,284	105.29
6	Crist	Coal (tons)	May-12	0	0	0.00	0	0	0.00	276,152	29,253	105.93
7	Crist	Coal (tons)	Jun-12	0	0	0.00	0	0	0.00	270,461	30,992	114.59
8	Crist	Coal (tons)	Jul-12	0	0	0.00	0	0	0.00	269,428	29,112	108.05
9	Crist	Coal (tons)	Aug-12	0	0	0.00	11	1	90.91	247,580	26,247	106.01
10	Crist	Coal (tons)	Sep-12	0	0	0.00	4,815	510	105.92	268,093	27,057	100.92
11	Crist	Coal (tons)	Oct-12	0	0	0.00	0	0	0.00	272,414	27,560	101.17
12	Crist	Coal (tons)	Nov-12	0	0	0.00	0	0	0.00	282,573	29,016	102.68
13	Crist	Coal (tons)	Dec-12	0	0	0.00	0	0	0.00	277,731	28,281	101.83
14	Total									3,511,510	376,978	
15	Crist	Coal (tons)	13 mth avg							270,116	28,998	107.35

16 Totals may not add due to rounding.

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide conventional fuel account balances in dollars and quantities for each fuel type for the test year and the two preceeding years. Include Natural Gas even though no Inventory is carried. (Give units in Barrels, Tons, or MCF)

Type of Data Shown:

_____ Projected Test Year Ended 12/31/14

_____ Prior Year Ended 12/31/13

X Historical Year Ended 12/31/12

Witness: M. L. Burroughs, S. D. Ritenour

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
				Beginning Inventory			Receipts			Fuel Issued to Generation		
Line No.	Plant	Fuel Type	Month	Units	($000)	$/Unit	Units	($000)	$/Unit	Units	($000)	$/Unit
1	Smith	Coal (tons)	Dec-11	224,551	27,228	121.26	28,236	4,412	156.25	37,122	4,646	125.15
2	Smith	Coal (tons)	Jan-12	215,666	26,993	125.16	27,012	3,399	125.83	25,890	3,242	125.22
3	Smith	Coal (tons)	Feb-12	216,787	27,150	125.24	23,588	4,348	184.33	24,500	3,210	131.02
4	Smith	Coal (tons)	Mar-12	215,875	28,288	131.04	47,326	5,322	112.45	24,702	3,162	128.01
5	Smith	Coal (tons)	Apr-12	248,628	31,821	127.99	54,049	6,143	113.66	38,202	4,792	125.44
6	Smith	Coal (tons)	May-12	264,476	33,172	125.43	29,569	3,045	102.98	38,779	4,776	123.16
7	Smith	Coal (tons)	Jun-12	255,266	31,441	123.17	25,122	2,719	108.23	24,122	3,016	125.03
8	Smith	Coal (tons)	Jul-12	256,265	31,144	121.53	39,650	3,869	97.58	53,918	6,379	118.31
9	Smith	Coal (tons)	Aug-12	241,997	28,634	118.32	36,047	3,684	102.20	49,994	5,811	116.23
10	Smith	Coal (tons)	Sep-12	228,051	26,507	116.23	20,543	1,962	95.51	35,575	4,074	114.52
11	Smith	Coal (tons)	Oct-12	213,018	24,395	114.52	22,529	2,308	102.45	25,182	2,855	113.37
12	Smith	Coal (tons)	Nov-12	210,365	23,848	113.36	30,745	2,949	95.92	29,692	3,300	111.14
13	Smith	Coal (tons)	Dec-12	211,418	23,497	111.14	24,241	2,463	101.60	24,646	2,715	110.16

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide conventional fuel account balances in dollars and quantities for each fuel type for the test year and the two preceeding years. Include Natural Gas even though no inventory is carried. (Give units in Barrels, Tons, or MCF)

Type of Data Shown:

_____ Projected Test Year Ended 12/31/14

_____ Prior Year Ended 12/31/13

X Historical Year Ended 12/31/12

Witness: M. L. Burroughs, S. D. Ritenour

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
				Fuel Issues (Other)			Adjustments			Ending Inventory		
Line No.	Plant	Fuel Type	Month	Units	($000)	$/Unit	Units	($000)	$/Unit	Units	($000)	$/Unit
1	Smith	Coal (tons)	Dec-11	0	0	0.00	0	0	0.00	215,666	26,993	125.16
2	Smith	Coal (tons)	Jan-12	0	0	0.00	0	0	0.00	216,787	27,150	125.24
3	Smith	Coal (tons)	Feb-12	0	0	0.00	0	0	0.00	215,875	28,288	131.04
4	Smith	Coal (tons)	Mar-12	0	0	0.00	10,130	1,373	135.54	248,628	31,821	127.99
5	Smith	Coal (tons)	Apr-12	0	0	0.00	0	0	0.00	264,476	33,172	125.43
6	Smith	Coal (tons)	May-12	0	0	0.00	0	0	0.00	255,266	31,441	123.17
7	Smith	Coal (tons)	Jun-12	0	0	0.00	0	0	0.00	256,265	31,144	121.53
8	Smith	Coal (tons)	Jul-12	0	0	0.00	0	0	0.00	241,997	28,634	118.32
9	Smith	Coal (tons)	Aug-12	0	0	0.00	0	0	0.00	228,051	26,507	116.23
10	Smith	Coal (tons)	Sep-12	0	0	0.00	0	0	0.00	213,018	24,395	114.52
11	Smith	Coal (tons)	Oct-12	0	0	0.00	0	0	0.00	210,365	23,848	113.36
12	Smith	Coal (tons)	Nov-12	0	0	0.00	0	0	0.00	211,418	23,497	111.14
13	Smith	Coal (tons)	Dec-12	0	0	0.00	0	0	0.00	211,013	23,245	110.16
14	Total									2,988,825	360,135	
15	Smith	Coal (tons)	13 mth avg							229,910	27,703	120.49

16 Totals may not add due to rounding.

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide conventional fuel account balances in dollars and quantities for each fuel type for the test year and the two preceeding years. Include Natural Gas even though no inventory is carried. (Give units in Barrels, Tons, or MCF)

Type of Data Shown:

_____ Projected Test Year Ended 12/31/14

_____ Prior Year Ended 12/31/13

X Historical Year Ended 12/31/12

Witness: M. L. Burroughs, S. D. Ritenour

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
				Beginning Inventory			Receipts			Fuel Issued to Generation		
Line No.	Plant	Fuel Type	Month	Units	($000)	$/Unit	Units	($000)	$/Unit	Units	($000)	$/Unit
1	Scholz	Coal (tons)	Dec-11	41,167	3,583	87.04	0	0	0.00	0	0	0.00
2	Scholz	Coal (tons)	Jan-12	41,167	3,583	87.04	0	20	0.00	0	0	0.00
3	Scholz	Coal (tons)	Feb-12	41,167	3,603	87.52	0	-25	0.00	0	0	0.00
4	Scholz	Coal (tons)	Mar-12	41,167	3,578	86.91	0	0	0.00	0	0	0.00
5	Scholz	Coal (tons)	Apr-12	41,167	3,578	86.91	0	0	0.00	0	0	0.00
6	Scholz	Coal (tons)	May-12	41,167	3,578	86.91	0	0	0.00	0	0	0.00
7	Scholz	Coal (tons)	Jun-12	41,167	3,579	86.94	0	0	0.00	11	1	90.91
8	Scholz	Coal (tons)	Jul-12	41,157	3,578	86.94	0	0	0.00	3,748	326	86.98
9	Scholz	Coal (tons)	Aug-12	37,409	3,252	86.93	0	0	0.00	13	1	76.92
10	Scholz	Coal (tons)	Sep-12	37,396	3,251	86.93	0	1	0.00	0	0	0.00
11	Scholz	Coal (tons)	Oct-12	37,396	3,252	86.96	0	0	0.00	0	0	0.00
12	Scholz	Coal (tons)	Nov-12	37,396	3,252	86.96	0	0	0.00	0	0	0.00
13	Scholz	Coal (tons)	Dec-12	37,396	3,252	86.96	0	0	0.00	0	0	0.00

Supporting Schedules:

Recap Schedules:

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FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide conventional fuel account balances in dollars and quantities for each fuel type for the test year and the two preceeding years. Include Natural Gas even though no inventory is carried. (Give units in Barrels, Tons, or MCF)

Type of Data Shown:
____ Projected Test Year Ended 12/31/14
____ Prior Year Ended 12/31/13
X Historical Year Ended 12/31/12
Witness: M. L. Burroughs, S. D. Ritenour

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
				Fuel Issues (Other)			Adjustments			Ending Inventory		
Line No.	Plant	Fuel Type	Month	Units	($000)	$/Unit	Units	($000)	$/Unit	Units	($000)	$/Unit
1	Scholz	Coal (tons)	Dec-11	0	0	0.00	0	0	0.00	41,167	3,583	87.04
2	Scholz	Coal (tons)	Jan-12	0	0	0.00	0	0	0.00	41,167	3,603	87.52
3	Scholz	Coal (tons)	Feb-12	0	0	0.00	0	0	0.00	41,167	3,578	86.91
4	Scholz	Coal (tons)	Mar-12	0	0	0.00	0	0	0.00	41,167	3,578	86.91
5	Scholz	Coal (tons)	Apr-12	0	0	0.00	0	0	0.00	41,167	3,578	86.91
6	Scholz	Coal (tons)	May-12	0	0	0.00	0	0	0.00	41,167	3,579	86.94
7	Scholz	Coal (tons)	Jun-12	0	0	0.00	0	0	0.00	41,157	3,578	86.94
8	Scholz	Coal (tons)	Jul-12	0	0	0.00	0	0	0.00	37,409	3,252	86.93
9	Scholz	Coal (tons)	Aug-12	0	0	0.00	0	0	0.00	37,396	3,251	86.93
10	Scholz	Coal (tons)	Sep-12	0	0	0.00	0	0	0.00	37,396	3,252	86.96
11	Scholz	Coal (tons)	Oct-12	0	0	0.00	0	0	0.00	37,396	3,252	86.96
12	Scholz	Coal (tons)	Nov-12	0	0	0.00	0	0	0.00	37,396	3,252	86.96
13	Scholz	Coal (tons)	Dec-12	0	0	0.00	0	0	0.00	37,396	3,252	86.96
14	Total									512,548	44,588	
15	Scholz	Coal (tons)	13 mth avg							39,427	3,430	87.00

16 Totals may not add due to rounding.

Supporting Schedules:

Recap Schedules:

Schedule B-18 | FUEL INVENTORY BY PLANT | Page 83 of 114

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide conventional fuel account balances in dollars and quantities for each fuel type for the test year and the two preceeding years. Include Natural Gas even though no inventory is carried. (Give units in Barrels, Tons, or MCF)

Type of Data Shown:
_____ Projected Test Year Ended 12/31/14
_____ Prior Year Ended 12/31/13
X Historical Year Ended 12/31/12
Witness: M. L. Burroughs, S. D. Ritenour

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
				Beginning Inventory			Receipts			Fuel Issued to Generation		
Line No.	Plant	Fuel Type	Month	Units	($000)	$/Unit	Units	($000)	$/Unit	Units	($000)	$/Unit
1	Daniel	Coal (tons)	Dec-11	381,036	33,168	87.05	66,142	5,804	87.75	61,943	5,398	87.14
2	Daniel	Coal (tons)	Jan-12	385,236	33,573	87.15	0	265	0.00	36,960	3,255	88.07
3	Daniel	Coal (tons)	Feb-12	348,276	30,584	87.82	30,836	3,114	100.99	32	3	93.75
4	Daniel	Coal (tons)	Mar-12	379,079	33,695	88.89	39,210	3,632	92.63	58,483	5,219	89.24
5	Daniel	Coal (tons)	Apr-12	359,806	32,108	89.24	57,030	5,936	104.09	63,381	5,769	91.02
6	Daniel	Coal (tons)	May-12	375,355	34,165	91.02	35,845	4,258	118.79	46,031	4,301	93.44
7	Daniel	Coal (tons)	Jun-12	365,169	34,122	93.44	43,895	5,078	115.69	37,199	3,565	95.84
8	Daniel	Coal (tons)	Jul-12	371,865	35,635	95.83	35,614	3,963	111.28	91,579	8,899	97.17
9	Daniel	Coal (tons)	Aug-12	315,900	30,698	97.18	24,170	2,836	117.34	75,270	7,422	98.61
10	Daniel	Coal (tons)	Sep-12	264,801	26,112	98.61	43,044	4,819	111.96	0	0	0.00
11	Daniel	Coal (tons)	Oct-12	308,075	30,954	100.48	61,252	6,949	113.45	7,823	803	102.65
12	Daniel	Coal (tons)	Nov-12	361,505	37,101	102.63	61,140	6,774	110.79	47,349	4,915	103.80
13	Daniel	Coal (tons)	Dec-12	375,296	38,959	103.81	36,772	5,142	139.83	0	0	0.00

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide conventional fuel account balances in dollars and quantities for each fuel type for the test year and the two preceeding years. Include Natural Gas even though no inventory is carried. (Give units in Barrels, Tons, or MCF)

Type of Data Shown:

____ Projected Test Year Ended 12/31/14

____ Prior Year Ended 12/31/13

X Historical Year Ended 12/31/12

Witness: M. L. Burroughs, S. D. Ritenour

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
				Fuel Issues (Other)			Adjustments			Ending Inventory		
Line No.	Plant	Fuel Type	Month	Units	($000)	$/Unit	Units	($000)	$/Unit	Units	($000)	$/Unit
1	Daniel	Coal (tons)	Dec-11	0	0	0.00	0	0	0.00	385,236	33,573	87.15
2	Daniel	Coal (tons)	Jan-12	0	0	0.00	0	0	0.00	348,276	30,584	87.82
3	Daniel	Coal (tons)	Feb-12	0	0	0.00	0	0	0.00	379,079	33,695	88.89
4	Daniel	Coal (tons)	Mar-12	0	0	0.00	0	0	0.00	359,806	32,108	89.24
5	Daniel	Coal (tons)	Apr-12	0	0	0.00	21,899	1,890	86.31	375,355	34,165	91.02
6	Daniel	Coal (tons)	May-12	0	0	0.00	0	0	0.00	365,169	34,122	93.44
7	Daniel	Coal (tons)	Jun-12	0	0	0.00	0	0	0.00	371,865	35,635	95.83
8	Daniel	Coal (tons)	Jul-12	0	0	0.00	0	0	0.00	315,900	30,698	97.18
9	Daniel	Coal (tons)	Aug-12	0	0	0.00	0	0	0.00	264,801	26,112	98.61
10	Daniel	Coal (tons)	Sep-12	0	0	0.00	231	23	99.57	308,075	30,954	100.48
11	Daniel	Coal (tons)	Oct-12	0	0	0.00	0	0	0.00	361,505	37,101	102.63
12	Daniel	Coal (tons)	Nov-12	0	0	0.00	0	0	0.00	375,296	38,959	103.81
13	Daniel	Coal (tons)	Dec-12	0	0	0.00	0	0	0.00	412,068	44,101	107.02
14	Total									4,622,431	441,807	
15	Daniel	Coal (tons)	13 mth avg							355,572	33,985	95.58

16 Totals may not add due to rounding.

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide conventional fuel account balances in dollars and quantities for each fuel type for the test year and the two preceeding years. Include Natural Gas even though no inventory is carried. (Give units in Barrels, Tons, or MCF)

Type of Data Shown:

_____ Projected Test Year Ended 12/31/14

_____ Prior Year Ended 12/31/13

X Historical Year Ended 12/31/12

Witness: M. L. Burroughs, S. D. Ritenour

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
				Beginning Inventory			Receipts			Fuel Issued to Generation		
Line No.	Plant	Fuel Type	Month	Units	($000)	$/Unit	Units	($000)	$/Unit	Units	($000)	$/Unit
1	Scherer	Coal (tons)	Dec-11	150,961	6,430	42.59	76,196	3,296	43.26	54,881	2,347	42.77
2	Scherer	Coal (tons)	Jan-12	173,666	7,438	42.83	68,208	3,046	44.66	25,873	1,121	43.33
3	Scherer	Coal (tons)	Feb-12	220,753	9,568	43.34	50,414	2,349	46.59	58,792	2,587	44.00
4	Scherer	Coal (tons)	Mar-12	216,136	9,460	43.77	66,031	3,098	45.54	75,244	3,318	44.10
5	Scherer	Coal (tons)	Apr-12	212,722	9,400	44.19	66,652	3,010	45.16	76,367	3,392	44.42
6	Scherer	Coal (tons)	May-12	198,077	8,803	44.44	56,585	2,643	46.71	63,405	2,850	44.95
7	Scherer	Coal (tons)	Jun-12	192,141	8,636	44.95	51,065	2,328	45.59	65,549	2,951	45.02
8	Scherer	Coal (tons)	Jul-12	178,979	8,073	45.11	59,157	2,737	46.27	75,487	3,427	45.40
9	Scherer	Coal (tons)	Aug-12	163,054	7,402	45.40	79,846	3,433	43.00	72,458	3,233	44.62
10	Scherer	Coal (tons)	Sep-12	170,989	7,626	44.60	65,276	2,913	44.63	59,472	2,653	44.61
11	Scherer	Coal (tons)	Oct-12	176,349	7,866	44.60	71,628	3,189	44.52	62,604	2,791	44.58
12	Scherer	Coal (tons)	Nov-12	182,850	8,051	44.03	62,688	2,799	44.65	61,361	2,711	44.18
13	Scherer	Coal (tons)	Dec-12	166,774	7,409	44.43	51,608	2,387	46.25	59,629	2,675	44.86

Supporting Schedules:

Recap Schedules:

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FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide conventional fuel account balances in dollars and quantities for each fuel type for the test year and the two preceeding years. Include Natural Gas even though no inventory is carried. (Give units in Barrels, Tons, or MCF)

Type of Data Shown:
_____ Projected Test Year Ended 12/31/14
_____ Prior Year Ended 12/31/13
X Historical Year Ended 12/31/12
Witness: M. L. Burroughs, S. D. Ritenour

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
				Fuel Issues (Other)			Adjustments			Ending Inventory		
Line No.	Plant	Fuel Type	Month	Units	($000)	$/Unit	Units	($000)	$/Unit	Units	($000)	$/Unit
1	Scherer	Coal (tons)	Dec-11	0	0	0.00	1,390	59	42.45	173,666	7,438	42.83
2	Scherer	Coal (tons)	Jan-12	0	0	0.00	4,751	206	43.36	220,753	9,568	43.34
3	Scherer	Coal (tons)	Feb-12	0	0	0.00	3,761	130	34.57	216,136	9,460	43.77
4	Scherer	Coal (tons)	Mar-12	0	0	0.00	3,799	160	42.12	212,722	9,400	44.19
5	Scherer	Coal (tons)	Apr-12	0	0	0.00	-4,930	-215	43.61	198,077	8,803	44.44
6	Scherer	Coal (tons)	May-12	0	0	0.00	884	40	45.25	192,141	8,636	44.95
7	Scherer	Coal (tons)	Jun-12	0	0	0.00	1,323	60	45.35	178,979	8,073	45.11
8	Scherer	Coal (tons)	Jul-12	0	0	0.00	404	18	44.55	163,054	7,402	45.40
9	Scherer	Coal (tons)	Aug-12	0	0	0.00	547	24	43.88	170,989	7,626	44.60
10	Scherer	Coal (tons)	Sep-12	0	0	0.00	-444	-20	45.05	176,349	7,866	44.60
11	Scherer	Coal (tons)	Oct-12	0	0	0.00	-2,522	-213	84.46	182,850	8,051	44.03
12	Scherer	Coal (tons)	Nov-12	0	0	0.00	-17,403	-730	41.95	166,774	7,409	44.43
13	Scherer	Coal (tons)	Dec-12	0	0	0.00	13,658	606	44.37	172,410	7,728	44.82
14	Total									2,424,900	107,460	
15	Scherer	Coal (tons)	13 mth avg							186,531	8,266	44.31

16 Totals may not add due to rounding.

Supporting Schedules:

Recap Schedules:

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FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide conventional fuel account balances in dollars and quantities for each fuel type for the test year and the two preceeding years. Include Natural Gas even though no inventory is carried. (Give units in Barrels, Tons, or MCF)

Type of Data Shown:

_____ Projected Test Year Ended 12/31/14

_____ Prior Year Ended 12/31/13

X Historical Year Ended 12/31/12

Witness: M. L. Burroughs, S. D. Ritenour

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
				Beginning Inventory			Receipts			Fuel Issued to Generation		
Line No.	Plant	Fuel Type	Month	Units	($000)	$/Unit	Units	($000)	$/Unit	Units	($000)	$/Unit
1	Cent. AL	CT Oil	Dec-11	9,283	770	82.95	0	0	0.00	0	0	0.00
2	Cent. AL	CT Oil	Jan-12	9,283	770	82.95	0	0	0.00	0	0	0.00
3	Cent. AL	CT Oil	Feb-12	9,283	770	82.95	0	0	0.00	0	0	0.00
4	Cent. AL	CT Oil	Mar-12	9,283	770	82.95	0	0	0.00	0	0	0.00
5	Cent. AL	CT Oil	Apr-12	9,283	770	82.95	0	0	0.00	0	0	0.00
6	Cent. AL	CT Oil	May-12	9,283	770	82.95	0	0	0.00	0	0	0.00
7	Cent. AL	CT Oil	Jun-12	9,283	770	82.95	0	0	0.00	0	0	0.00
8	Cent. AL	CT Oil	Jul-12	9,283	770	82.95	0	0	0.00	0	0	0.00
9	Cent. AL	CT Oil	Aug-12	9,283	770	82.95	0	0	0.00	0	0	0.00
10	Cent. AL	CT Oil	Sep-12	9,283	770	82.95	0	0	0.00	0	0	0.00
11	Cent. AL	CT Oil	Oct-12	9,283	770	82.95	0	0	0.00	0	0	0.00
12	Cent. AL	CT Oil	Nov-12	9,283	770	82.95	0	0	0.00	0	0	0.00
13	Cent. AL	CT Oil	Dec-12	9,283	770	82.95	0	0	0.00	0	0	0.00

14 Note: Gulf provides the fuel to operate these units per the Purchase Power Agreement.

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide conventional fuel account balances in dollars and quantities for each fuel type for the test year and the two preceeding years. Include Natural Gas even though no inventory is carried. (Give units In Barrels, Tons, or MCF)

Type of Data Shown:

____ Projected Test Year Ended 12/31/14

____ Prior Year Ended 12/31/13

X Historical Year Ended 12/31/12

Witness: M. L. Burroughs, S. D. Ritenour

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
				Fuel Issues (Other)			Adjustments			Ending Inventory		
Line No.	Plant	Fuel Type	Month	Units	($000)	$/Unit	Units	($000)	$/Unit	Units	($000)	$/Unit
1	Cent. AL	CT Oil	Dec-11	0	0	0.00	0	0	0.00	9,283	770	82.95
2	Cent. AL	CT Oil	Jan-12	0	0	0.00	0	0	0.00	9,283	770	82.95
3	Cent. AL	CT Oil	Feb-12	0	0	0.00	0	0	0.00	9,283	770	82.95
4	Cent. AL	CT Oil	Mar-12	0	0	0.00	0	0	0.00	9,283	770	82.95
5	Cent. AL	CT Oil	Apr-12	0	0	0.00	0	0	0.00	9,283	770	82.95
6	Cent. AL	CT Oil	May-12	0	0	0.00	0	0	0.00	9,283	770	82.95
7	Cent. AL	CT Oil	Jun-12	0	0	0.00	0	0	0.00	9,283	770	82.95
8	Cent. AL	CT Oil	Jul-12	0	0	0.00	0	0	0.00	9,283	770	82.95
9	Cent. AL	CT Oil	Aug-12	0	0	0.00	0	0	0.00	9,283	770	82.95
10	Cent. AL	CT Oil	Sep-12	0	0	0.00	0	0	0.00	9,283	770	82.95
11	Cent. AL	CT Oil	Oct-12	0	0	0.00	0	0	0.00	9,283	770	82.95
12	Cent. AL	CT Oil	Nov-12	0	0	0.00	0	0	0.00	9,283	770	82.95
13	Cent. AL	CT Oil	Dec-12	0	0	0.00	0	0	0.00	9,283	770	82.95
14	Total									120,679	10,010	
15	Cent. AL	CT Oil	13 mth avg							9,283	770	82.95

16 Note: Gulf provides the fuel to operate these units per the Purchase Power Agreement.

17 Totals may not add due to rounding.

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide conventional fuel account balances in dollars and quantities for each fuel type for the test year and the two preceeding years. Include Natural Gas even though no inventory is carried. (Give units in Barrels, Tons, or MCF)

Type of Data Shown:

____ Projected Test Year Ended 12/31/14

____ Prior Year Ended 12/31/13

X Historical Year Ended 12/31/12

Witness: M. L. Burroughs, S. D. Ritenour

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
				Beginning Inventory			Receipts			Fuel Issued to Generation		
Line No.	Plant	Fuel Type	Month	Units	($000)	$/Unit	Units	($000)	$/Unit	Units	($000)	$/Unit
1	Baconton	CT Oil	Dec-11	8,609	742	86.19	0	0	0.00	0	0	0.00
2	Baconton	CT Oil	Jan-12	8,609	742	86.19	0	0	0.00	0	0	0.00
3	Baconton	CT Oil	Feb-12	8,609	742	86.19	0	0	0.00	570	49	85.96
4	Baconton	CT Oil	Mar-12	8,039	693	86.20	0	0	0.00	0	0	0.00
5	Baconton	CT Oil	Apr-12	8,077	696	86.17	0	0	0.00	0	0	0.00
6	Baconton	CT Oil	May-12	8,077	696	86.17	0	0	0.00	0	0	0.00
7	Baconton	CT Oil	Jun-12	8,077	696	86.17	0	0	0.00	0	0	0.00
8	Baconton	CT Oil	Jul-12	8,077	696	86.17	0	0	0.00	0	0	0.00
9	Baconton	CT Oil	Aug-12	8,077	696	86.17	0	0	0.00	0	0	0.00
10	Baconton	CT Oil	Sep-12	8,077	696	86.17	0	0	0.00	0	0	0.00
11	Baconton	CT Oil	Oct-12	8,077	696	86.17	0	0	0.00	0	0	0.00
12	Baconton	CT Oil	Nov-12	8,077	696	86.17	0	0	0.00	0	0	0.00
13	Baconton	CT Oil	Dec-12	8,077	696	86.17	0	0	0.00	0	0	0.00

14 Note: Gulf provides the fuel to operate these units per the Purchase Power Agreement.

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide conventional fuel account balances in dollars and quantities for each fuel type for the test year and the two preceeding years. Include Natural Gas even though no inventory is carried. (Give units in Barrels, Tons, or MCF)

Type of Data Shown:

_____ Projected Test Year Ended 12/31/14

_____ Prior Year Ended 12/31/13

X Historical Year Ended 12/31/12

Witness: M. L. Burroughs, S. D. Ritenour

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
				Fuel Issues (Other)			Adjustments			Ending Inventory		
Line No.	Plant	Fuel Type	Month	Units	($000)	$/Unit	Units	($000)	$/Unit	Units	($000)	$/Unit
1	Baconton	CT Oil	Dec-11	0	0	0.00	0	0	0.00	8,609	742	86.19
2	Baconton	CT Oil	Jan-12	0	0	0.00	0	0	0.00	8,609	742	86.19
3	Baconton	CT Oil	Feb-12	0	0	0.00	0	0	0.00	8,039	693	86.20
4	Baconton	CT Oil	Mar-12	0	0	0.00	38	3	78.95	8,077	696	86.17
5	Baconton	CT Oil	Apr-12	0	0	0.00	0	0	0.00	8,077	696	86.17
6	Baconton	CT Oil	May-12	0	0	0.00	0	0	0.00	8,077	696	86.17
7	Baconton	CT Oil	Jun-12	0	0	0.00	0	0	0.00	8,077	696	86.17
8	Baconton	CT Oil	Jul-12	0	0	0.00	0	0	0.00	8,077	696	86.17
9	Baconton	CT Oil	Aug-12	0	0	0.00	0	0	0.00	8,077	696	86.17
10	Baconton	CT Oil	Sep-12	0	0	0.00	0	0	0.00	8,077	696	86.17
11	Baconton	CT Oil	Oct-12	0	0	0.00	0	0	0.00	8,077	696	86.17
12	Baconton	CT Oil	Nov-12	0	0	0.00	0	0	0.00	8,077	696	86.17
13	Baconton	CT Oil	Dec-12	0	0	0.00	0	0	0.00	8,077	696	86.17
14	Total									106,027	9,137	
15	Baconton	CT Oil	13 mth avg							8,156	703	86.19

16 Note: Gulf provides the fuel to operate these units per the Purchase Power Agreement.

17 Totals may not add due to rounding.

Supporting Schedules:

Recap Schedules:

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FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide conventional fuel account balances in dollars and quantities for each fuel type for the test year and the two preceeding years. Include Natural Gas even though no inventory is carried. (Give units in Barrels, Tons, or MCF)

Type of Data Shown:

____ Projected Test Year Ended 12/31/14

____ Prior Year Ended 12/31/13

X Historical Year Ended 12/31/12

Witness: M. L. Burroughs, S. D. Ritenour

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
				Beginning Inventory			Receipts			Fuel Issued to Generation		
Line No.	Plant	Fuel Type	Month	Units	($000)	$/Unit	Units	($000)	$/Unit	Units	($000)	$/Unit
1	Dahlberg	CT Oil	Dec-11	11,455	1,031	90.00	0	0	0.00	201	18	89.55
2	Dahlberg	CT Oil	Jan-12	11,254	1,013	90.01	0	0	0.00	0	0	0.00
3	Dahlberg	CT Oil	Feb-12	11,254	1,013	90.01	0	0	0.00	0	0	0.00
4	Dahlberg	CT Oil	Mar-12	11,254	1,013	90.01	0	0	0.00	0	0	0.00
5	Dahlberg	CT Oil	Apr-12	11,254	1,013	90.01	0	0	0.00	0	0	0.00
6	Dahlberg	CT Oil	May-12	11,254	1,013	90.01	0	0	0.00	0	0	0.00
7	Dahlberg	CT Oil	Jun-12	11,254	1,013	90.01	0	0	0.00	0	0	0.00
8	Dahlberg	CT Oil	Jul-12	11,254	1,013	90.01	0	0	0.00	0	0	0.00
9	Dahlberg	CT Oil	Aug-12	11,254	1,013	90.01	0	0	0.00	0	0	0.00
10	Dahlberg	CT Oil	Sep-12	11,254	1,013	90.01	0	0	0.00	0	0	0.00
11	Dahlberg	CT Oil	Oct-12	11,254	1,013	90.01	0	0	0.00	0	0	0.00
12	Dahlberg	CT Oil	Nov-12	11,254	1,013	90.01	0	0	0.00	256	23	89.84
13	Dahlberg	CT Oil	Dec-12	10,998	990	90.02	0	0	0.00	87	8	91.95

14 Note: Gulf provides the fuel to operate these units per the Purchase Power Agreement.

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide conventional fuel account balances in dollars and quantities for each fuel type for the test year and the two preceeding years. Include Natural Gas even though no inventory is carried. (Give units in Barrels, Tons, or MCF)

Type of Data Shown:
____ Projected Test Year Ended 12/31/14
____ Prior Year Ended 12/31/13
X Historical Year Ended 12/31/12
Witness: M. L. Burroughs, S. D. Ritenour

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
				Fuel Issues (Other)			Adjustments			Ending Inventory		
Line No.	Plant	Fuel Type	Month	Units	($000)	$/Unit	Units	($000)	$/Unit	Units	($000)	$/Unit
1	Dahlberg	CT Oil	Dec-11	0	0	0.00	0	0	0.00	11,254	1,013	90.01
2	Dahlberg	CT Oil	Jan-12	0	0	0.00	0	0	0.00	11,254	1,013	90.01
3	Dahlberg	CT Oil	Feb-12	0	0	0.00	0	0	0.00	11,254	1,013	90.01
4	Dahlberg	CT Oil	Mar-12	0	0	0.00	0	0	0.00	11,254	1,013	90.01
5	Dahlberg	CT Oil	Apr-12	0	0	0.00	0	0	0.00	11,254	1,013	90.01
6	Dahlberg	CT Oil	May-12	0	0	0.00	0	0	0.00	11,254	1,013	90.01
7	Dahlberg	CT Oil	Jun-12	0	0	0.00	0	0	0.00	11,254	1,013	90.01
8	Dahlberg	CT Oil	Jul-12	0	0	0.00	0	0	0.00	11,254	1,013	90.01
9	Dahlberg	CT Oil	Aug-12	0	0	0.00	0	0	0.00	11,254	1,013	90.01
10	Dahlberg	CT Oil	Sep-12	0	0	0.00	0	0	0.00	11,254	1,013	90.01
11	Dahlberg	CT Oil	Oct-12	0	0	0.00	0	0	0.00	11,254	1,013	90.01
12	Dahlberg	CT Oil	Nov-12	0	0	0.00	0	0	0.00	10,998	990	90.02
13	Dahlberg	CT Oil	Dec-12	0	0	0.00	0	0	0.00	10,911	982	90.00
14	Total									145,703	13,115	
15	Dahlberg	CT Oil	13 mth avg							11,208	1,009	90.02

16 Note: Gulf provides the fuel to operate these units per the Purchase Power Agreement.
17 Totals may not add due to rounding.

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide conventional fuel account balances in dollars and quantities for each fuel type for the test year and the two preceeding years. Include Natural Gas even though no inventory is carried. (Give units in Barrels, Tons, or MCF)

Type of Data Shown:

____ Projected Test Year Ended 12/31/14

____ Prior Year Ended 12/31/13

X Historical Year Ended 12/31/12

Witness: M. L. Burroughs, S. D. Ritenour

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
				Beginning Inventory			Receipts			Fuel Issued to Generation		
Line No.	Plant	Fuel Type	Month	Units	($000)	$/Unit	Units	($000)	$/Unit	Units	($000)	$/Unit
1	Smith	CT Oil	Dec-11	5,219	467	89.48	1796	234	130.29	188	19	101.06
2	Smith	CT Oil	Jan-12	6,826	682	99.91	0	0	0.00	204	20	98.04
3	Smith	CT Oil	Feb-12	6,622	662	99.97	0	0	0.00	157	16	101.91
4	Smith	CT Oil	Mar-12	6,466	646	99.91	0	0	0.00	78	8	102.56
5	Smith	CT Oil	Apr-12	6,387	638	99.89	710	99	139.44	491	51	103.87
6	Smith	CT Oil	May-12	6,606	686	103.84	0	0	0.00	0	0	0.00
7	Smith	CT Oil	Jun-12	6,606	686	103.84	0	0	0.00	0	0	0.00
8	Smith	CT Oil	Jul-12	6,522	678	103.96	354	44	124.29	298	31	104.03
9	Smith	CT Oil	Aug-12	6,490	681	104.93	0	0	0.00	23	2	86.96
10	Smith	CT Oil	Sep-12	6,467	679	104.99	0	0	0.00	16	2	125.00
11	Smith	CT Oil	Oct-12	6,451	677	104.94	354	49	138.42	685	73	106.57
12	Smith	CT Oil	Nov-12	6,120	653	106.70	0	0	0.00	0	0	0.00
13	Smith	CT Oil	Dec-12	6,120	653	106.70	0	0	0.00	93	10	107.53

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Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide conventional fuel account balances in dollars and quantities for each fuel type for the test year and the two preceeding years. Include Natural Gas even though no inventory is carried. (Give units in Barrels, Tons, or MCF)

Type of Data Shown:

_____ Projected Test Year Ended 12/31/14

_____ Prior Year Ended 12/31/13

X Historical Year Ended 12/31/12

Witness: M. L. Burroughs, S. D. Ritenour

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
				Fuel Issues (Other)			Adjustments			Ending Inventory		
Line No.	Plant	Fuel Type	Month	Units	($000)	$/Unit	Units	($000)	$/Unit	Units	($000)	$/Unit
1	Smith	CT Oil	Dec-11	0	0	0.00	0	0	0.00	6,826	682	99.91
2	Smith	CT Oil	Jan-12	0	0	0.00	0	0	0.00	6,622	662	99.97
3	Smith	CT Oil	Feb-12	0	0	0.00	0	0	0.00	6,466	646	99.91
4	Smith	CT Oil	Mar-12	0	0	0.00	0	0	0.00	6,387	638	99.89
5	Smith	CT Oil	Apr-12	0	0	0.00	0	0	0.00	6,606	686	103.84
6	Smith	CT Oil	May-12	0	0	0.00	0	0	0.00	6,606	686	103.84
7	Smith	CT Oil	Jun-12	0	0	0.00	-85	-9	105.88	6,522	678	103.96
8	Smith	CT Oil	Jul-12	0	0	0.00	-88	-9	102.27	6,490	681	104.93
9	Smith	CT Oil	Aug-12	0	0	0.00	0	0	0.00	6,467	679	104.99
10	Smith	CT Oil	Sep-12	0	0	0.00	0	0	0.00	6,451	677	104.94
11	Smith	CT Oil	Oct-12	0	0	0.00	0	0	0.00	6,120	653	106.70
12	Smith	CT Oil	Nov-12	0	0	0.00	0	0	0.00	6,120	653	106.70
13	Smith	CT Oil	Dec-12	0	0	0.00	-73	-8	109.59	5,955	635	106.63
14	Total									83,638	8,656	
15	Smith	CT Oil	13 mth avg							6,434	666	103.51

16 Totals may not add due to rounding.

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide conventional fuel account balances in dollars and quantities for each fuel type for the test year and the two preceeding years. Include Natural Gas even though no inventory is carried. (Give units in Barrels, Tons, or MCF)

Type of Data Shown:

_____ Projected Test Year Ended 12/31/14

_____ Prior Year Ended 12/31/13

X Historical Year Ended 12/31/12

Witness: M. L. Burroughs, S. D. Ritenour

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
				Beginning Inventory			Receipts			Fuel Issued to Generation		
Line No.	Plant	Fuel Type	Month	Units	($000)	$/Unit	Units	($000)	$/Unit	Units	($000)	$/Unit
1	Crist	Oil	Dec-11	2,719	303	111.44	0	0	0.00	188	21	111.70
2	Crist	Oil	Jan-12	2,531	282	111.42	0	0	0.00	161	18	111.80
3	Crist	Oil	Feb-12	2,370	264	111.39	0	0	0.00	282	31	109.93
4	Crist	Oil	Mar-12	2,088	233	111.59	0	0	0.00	81	9	111.11
5	Crist	Oil	Apr-12	2,007	224	111.61	0	0	0.00	134	15	111.94
6	Crist	Oil	May-12	1,873	209	111.59	0	0	0.00	107	12	112.15
7	Crist	Oil	Jun-12	1,765	197	111.61	1,591	186	116.91	281	32	113.88
8	Crist	Oil	Jul-12	3,075	351	114.15	0	0	0.00	81	9	111.11
9	Crist	Oil	Aug-12	2,994	342	114.23	0	0	0.00	322	37	114.91
10	Crist	Oil	Sep-12	2,672	305	114.15	0	0	0.00	289	33	114.19
11	Crist	Oil	Oct-12	2,383	272	114.14	710	100	140.85	79	9	113.92
12	Crist	Oil	Nov-12	3,014	362	120.11	0	0	0.00	188	23	122.34
13	Crist	Oil	Dec-12	2,826	340	120.31	0	0	0.00	175	21	120.00

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

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Type of Data Shown:

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X Historical Year Ended 12/31/12

Witness: M. L. Burroughs, S. D. Ritenour

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
				Fuel Issues (Other)			Adjustments			Ending Inventory		
Line No.	Plant	Fuel Type	Month	Units	($000)	$/Unit	Units	($000)	$/Unit	Units	($000)	$/Unit
1	Crist	Oil	Dec-11	0	0	0.00	0	0	0.00	2,531	282	111.42
2	Crist	Oil	Jan-12	0	0	0.00	0	0	0.00	2,370	264	111.39
3	Crist	Oil	Feb-12	0	0	0.00	0	0	0.00	2,088	233	111.59
4	Crist	Oil	Mar-12	0	0	0.00	0	0	0.00	2,007	224	111.61
5	Crist	Oil	Apr-12	0	0	0.00	0	0	0.00	1,873	209	111.59
6	Crist	Oil	May-12	0	0	0.00	0	0	0.00	1,765	197	111.61
7	Crist	Oil	Jun-12	0	0	0.00	0	0	0.00	3,075	351	114.15
8	Crist	Oil	Jul-12	0	0	0.00	0	0	0.00	2,994	342	114.23
9	Crist	Oil	Aug-12	0	0	0.00	0	0	0.00	2,672	305	114.15
10	Crist	Oil	Sep-12	0	0	0.00	0	0	0.00	2,383	272	114.14
11	Crist	Oil	Oct-12	0	0	0.00	0	0	0.00	3,014	362	120.11
12	Crist	Oil	Nov-12	0	0	0.00	0	0	0.00	2,826	340	120.31
13	Crist	Oil	Dec-12	0	0	0.00	0	0	0.00	2,652	319	120.29
14	Total									32,250	3,700	
15	Crist	Oil	13 mth avg							2,481	285	114.87

16 Totals may not add due to rounding.

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide conventional fuel account balances in dollars and quantities for each fuel type for the test year and the two preceeding years. Include Natural Gas even though no inventory is carried. (Give units in Barrels, Tons, or MCF)

Type of Data Shown:

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X Historical Year Ended 12/31/12

Witness: M. L. Burroughs, S. D. Ritenour

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
				Beginning Inventory			Receipts			Fuel Issued to Generation		
Line No.	Plant	Fuel Type	Month	Units	($000)	$/Unit	Units	($000)	$/Unit	Units	($000)	$/Unit
1	Smith	Oil	Dec-11	245	32	130.61	357	44	123.25	404	51	126.24
2	Smith	Oil	Jan-12	198	25	126.26	0	0	0.00	88	11	125.00
3	Smith	Oil	Feb-12	110	14	127.27	178	25	140.45	138	18	130.43
4	Smith	Oil	Mar-12	151	20	132.45	178	25	140.45	193	27	139.90
5	Smith	Oil	Apr-12	135	19	140.74	710	100	140.85	711	100	140.65
6	Smith	Oil	May-12	134	19	141.79	529	68	128.54	403	52	129.03
7	Smith	Oil	Jun-12	261	34	130.27	0	0	0.00	167	22	131.74
8	Smith	Oil	Jul-12	93	12	129.03	707	90	127.30	669	85	127.06
9	Smith	Oil	Aug-12	131	17	129.77	1,061	146	137.61	1,080	147	136.11
10	Smith	Oil	Sep-12	112	15	133.93	883	123	139.30	860	120	139.53
11	Smith	Oil	Oct-12	135	19	140.74	178	24	134.83	147	20	136.05
12	Smith	Oil	Nov-12	165	23	139.39	535	71	132.71	522	70	134.10
13	Smith	Oil	Dec-12	178	24	134.83	0	0	0.00	28	4	142.86

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide conventional fuel account balances in dollars and quantities for each fuel type for the test year and the two preceeding years. Include Natural Gas even though no inventory is carried. (Give units in Barrels, Tons, or MCF)

Type of Data Shown:

____ Projected Test Year Ended 12/31/14

____ Prior Year Ended 12/31/13

X Historical Year Ended 12/31/12

Witness: M. L. Burroughs, S. D. Ritenour

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
				Fuel Issues (Other)			Adjustments			Ending Inventory		
Line No.	Plant	Fuel Type	Month	Units	($000)	$/Unit	Units	($000)	$/Unit	Units	($000)	$/Unit
1	Smith	Oil	Dec-11	0	0	0.00	0	0	0.00	198	25	126.26
2	Smith	Oil	Jan-12	0	0	0.00	0	0	0.00	110	14	127.27
3	Smith	Oil	Feb-12	0	0	0.00	0	0	0.00	151	20	132.45
4	Smith	Oil	Mar-12	0	0	0.00	0	0	0.00	135	19	140.74
5	Smith	Oil	Apr-12	0	0	0.00	0	0	0.00	134	19	141.79
6	Smith	Oil	May-12	0	0	0.00	0	0	0.00	261	34	130.27
7	Smith	Oil	Jun-12	0	0	0.00	0	0	0.00	93	12	129.03
8	Smith	Oil	Jul-12	0	0	0.00	0	0	0.00	131	17	129.77
9	Smith	Oil	Aug-12	0	0	0.00	0	0	0.00	112	15	133.93
10	Smith	Oil	Sep-12	0	0	0.00	0	0	0.00	135	19	140.74
11	Smith	Oil	Oct-12	0	0	0.00	0	0	0.00	165	23	139.39
12	Smith	Oil	Nov-12	0	0	0.00	0	0	0.00	178	24	134.83
13	Smith	Oil	Dec-12	0	0	0.00	307	41	133.55	457	61	133.48
14	Total									2,260	302	
15	Smith	Oil	13 mth avg							174	23	132.18

16 Totals may not add due to rounding.

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide conventional fuel account balances in dollars and quantities for each fuel type for the test year and the two preceeding years. Include Natural Gas even though no inventory is carried. (Give units in Barrels, Tons, or MCF)

Type of Data Shown:

____ Projected Test Year Ended 12/31/14

____ Prior Year Ended 12/31/13

X Historical Year Ended 12/31/12

Witness: M. L. Burroughs, S. D. Ritenour

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
				Beginning Inventory			Receipts			Fuel Issued to Generation		
Line No.	Plant	Fuel Type	Month	Units	($000)	$/Unit	Units	($000)	$/Unit	Units	($000)	$/Unit
1	Scholz	Oil	Dec-11	133	17	127.82	179	23	128.49	3	0	0.00
2	Scholz	Oil	Jan-12	308	39	126.62	0	0	0.00	0	0	0.00
3	Scholz	Oil	Feb-12	304	38	125.00	0	0	0.00	11	1	90.91
4	Scholz	Oil	Mar-12	293	37	126.28	0	0	0.00	8	1	125.00
5	Scholz	Oil	Apr-12	286	36	125.87	0	0	0.00	5	1	200.00
6	Scholz	Oil	May-12	280	35	125.00	0	0	0.00	0	0	0.00
7	Scholz	Oil	Jun-12	280	35	125.00	0	0	0.00	12	2	166.67
8	Scholz	Oil	Jul-12	268	34	126.87	0	0	0.00	59	8	135.59
9	Scholz	Oil	Aug-12	209	26	124.40	94	13	138.30	21	3	142.86
10	Scholz	Oil	Sep-12	282	37	131.21	0	0	0.00	8	1	125.00
11	Scholz	Oil	Oct-12	274	36	131.39	0	0	0.00	6	1	166.67
12	Scholz	Oil	Nov-12	268	35	130.60	0	0	0.00	5	1	200.00
13	Scholz	Oil	Dec-12	263	34	129.28	0	0	0.00	2	0	0.00

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

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DOCKET NO.: 130140-EI

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Type of Data Shown:

_____ Projected Test Year Ended 12/31/14

_____ Prior Year Ended 12/31/13

X Historical Year Ended 12/31/12

Witness: M. L. Burroughs, S. D. Ritenour

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
				Fuel Issues (Other)			Adjustments			Ending Inventory		
Line No.	Plant	Fuel Type	Month	Units	($000)	$/Unit	Units	($000)	$/Unit	Units	($000)	$/Unit
1	Scholz	Oil	Dec-11	0	0	0.00	0	0	0.00	308	39	126.62
2	Scholz	Oil	Jan-12	0	0	0.00	-4	-1	250.00	304	38	125.00
3	Scholz	Oil	Feb-12	0	0	0.00	0	0	0.00	293	37	126.28
4	Scholz	Oil	Mar-12	0	0	0.00	0	0	0.00	286	36	125.87
5	Scholz	Oil	Apr-12	0	0	0.00	0	0	0.00	280	35	125.00
6	Scholz	Oil	May-12	0	0	0.00	0	0	0.00	280	35	125.00
7	Scholz	Oil	Jun-12	0	0	0.00	0	0	0.00	268	34	126.87
8	Scholz	Oil	Jul-12	0	0	0.00	0	0	0.00	209	26	124.40
9	Scholz	Oil	Aug-12	0	0	0.00	0	0	0.00	282	37	131.21
10	Scholz	Oil	Sep-12	0	0	0.00	0	0	0.00	274	36	131.39
11	Scholz	Oil	Oct-12	0	0	0.00	0	0	0.00	268	35	130.60
12	Scholz	Oil	Nov-12	0	0	0.00	0	0	0.00	263	34	129.28
13	Scholz	Oil	Dec-12	0	0	0.00	0	0	0.00	261	34	130.27
14	Total									3,576	456	
15	Scholz	Oil	13 mth avg							275	35	127.27

16 Totals may not add due to rounding.

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide conventional fuel account balances in dollars and quantities for each fuel type for the test year and the two preceeding years. Include Natural Gas even though no inventory is carried. (Give units in Barrels, Tons, or MCF)

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X Historical Year Ended 12/31/12

Witness: M. L. Burroughs, S. D. Ritenour

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
				Beginning Inventory			Receipts			Fuel Issued to Generation		
Line No.	Plant	Fuel Type	Month	Units	($000)	$/Unit	Units	($000)	$/Unit	Units	($000)	$/Unit
1	Daniel	Oil	Dec-11	2,028	250	123.27	1,879	236	125.60	1,556	194	124.68
2	Daniel	Oil	Jan-12	2,351	293	124.63	977	129	132.04	879	111	126.28
3	Daniel	Oil	Feb-12	2,448	310	126.63	266	35	131.58	0	0	0.00
4	Daniel	Oil	Mar-12	2,714	345	127.12	0	0	0.00	683	87	127.38
5	Daniel	Oil	Apr-12	2,032	258	126.97	0	0	0.00	41	5	121.95
6	Daniel	Oil	May-12	1,990	253	127.14	2,462	313	127.13	1,976	251	127.02
7	Daniel	Oil	Jun-12	2,476	315	127.22	439	50	113.90	486	61	125.51
8	Daniel	Oil	Jul-12	2,429	304	125.15	527	64	121.44	345	43	124.64
9	Daniel	Oil	Aug-12	2,611	326	124.86	36	11	305.56	2,099	267	127.20
10	Daniel	Oil	Sep-12	547	70	127.97	2,565	351	136.84	0	0	0.00
11	Daniel	Oil	Oct-12	3,112	421	135.28	0	7	0.00	356	49	137.64
12	Daniel	Oil	Nov-12	2,756	379	137.52	0	0	0.00	159	22	138.36
13	Daniel	Oil	Dec-12	2,598	357	137.41	0	0	0.00	0	0	0.00

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide conventional fuel account balances in dollars and quantities for each fuel type for the test year and the two preceeding years. Include Natural Gas even though no inventory is carried. (Give units in Barrels, Tons, or MCF)

Type of Data Shown:
____ Projected Test Year Ended 12/31/14
____ Prior Year Ended 12/31/13
X Historical Year Ended 12/31/12
Witness: M. L. Burroughs, S. D. Ritenour

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
				Fuel Issues (Other)			Adjustments			Ending Inventory		
Line No.	Plant	Fuel Type	Month	Units	($000)	$/Unit	Units	($000)	$/Unit	Units	($000)	$/Unit
1	Daniel	Oil	Dec-11	0	0	0.00	0	0	0.00	2,351	293	124.63
2	Daniel	Oil	Jan-12	0	0	0.00	0	0	0.00	2,448	310	126.63
3	Daniel	Oil	Feb-12	0	0	0.00	0	0	0.00	2,714	345	127.12
4	Daniel	Oil	Mar-12	0	0	0.00	0	0	0.00	2,032	258	126.97
5	Daniel	Oil	Apr-12	0	0	0.00	0	0	0.00	1,990	253	127.14
6	Daniel	Oil	May-12	0	0	0.00	0	0	0.00	2,476	315	127.22
7	Daniel	Oil	Jun-12	0	0	0.00	0	0	0.00	2,429	304	125.15
8	Daniel	Oil	Jul-12	0	0	0.00	0	0	0.00	2,611	326	124.86
9	Daniel	Oil	Aug-12	0	0	0.00	0	0	0.00	547	70	127.97
10	Daniel	Oil	Sep-12	0	0	0.00	0	0	0.00	3,112	421	135.28
11	Daniel	Oil	Oct-12	0	0	0.00	0	0	0.00	2,756	379	137.52
12	Daniel	Oil	Nov-12	0	0	0.00	0	0	0.00	2,598	357	137.41
13	Daniel	Oil	Dec-12	0	0	0.00	0	0	0.00	2,598	357	137.41
14	Total									30,662	3,988	
15	Daniel	Oil	13 mth avg							2,359	307	130.14

16 Totals may not add due to rounding.

Supporting Schedules:

Recap Schedules:

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FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide conventional fuel account balances in dollars and quantities for each fuel type for the test year and the two preceeding years. Include Natural Gas even though no inventory is carried. (Give units in Barrels, Tons, or MCF)

Type of Data Shown:

_____ Projected Test Year Ended 12/31/14

_____ Prior Year Ended 12/31/13

X Historical Year Ended 12/31/12

Witness: M. L. Burroughs, S. D. Ritenour

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
				Beginning Inventory			Receipts			Fuel Issued to Generation		
Line No.	Plant	Fuel Type	Month	Units	($000)	$/Unit	Units	($000)	$/Unit	Units	($000)	$/Unit
1	Scherer	Oil	Dec-11	1,284	167	130.06	526	69	131.18	735	96	130.61
2	Scherer	Oil	Jan-12	1,322	172	130.11	269	37	137.55	723	95	131.40
3	Scherer	Oil	Feb-12	1,338	176	131.54	269	39	144.98	377	50	132.63
4	Scherer	Oil	Mar-12	1,319	177	134.19	134	20	149.25	211	29	137.44
5	Scherer	Oil	Apr-12	1,287	174	135.20	134	20	149.25	112	15	133.93
6	Scherer	Oil	May-12	1,296	177	136.57	267	37	138.58	67	9	134.33
7	Scherer	Oil	Jun-12	1,336	183	136.98	44	5	113.64	65	9	138.46
8	Scherer	Oil	Jul-12	1,353	184	135.99	66	9	136.36	92	13	141.30
9	Scherer	Oil	Aug-12	1,311	178	135.77	133	19	142.86	102	14	137.25
10	Scherer	Oil	Sep-12	1,313	180	137.09	66	10	151.52	56	8	142.86
11	Scherer	Oil	Oct-12	1,324	182	137.46	133	19	142.86	48	7	145.83
12	Scherer	Oil	Nov-12	1,395	193	138.35	0	0	0.00	72	10	138.89
13	Scherer	Oil	Dec-12	1,338	185	138.27	100	14	140.00	26	4	153.85

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

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DOCKET NO.: 130140-EI

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Type of Data Shown:

_____ Projected Test Year Ended 12/31/14

_____ Prior Year Ended 12/31/13

X Historical Year Ended 12/31/12

Witness: M. L. Burroughs, S. D. Ritenour

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
				Fuel Issues (Other)			Adjustments			Ending Inventory		
Line No.	Plant	Fuel Type	Month	Units	($000)	$/Unit	Units	($000)	$/Unit	Units	($000)	$/Unit
1	Scherer	Oil	Dec-11	0	0	0.00	247	32	129.55	1,322	172	130.11
2	Scherer	Oil	Jan-12	0	0	0.00	471	62	131.63	1,338	176	131.54
3	Scherer	Oil	Feb-12	0	0	0.00	89	12	134.83	1,319	177	134.19
4	Scherer	Oil	Mar-12	0	0	0.00	45	6	133.33	1,287	174	135.20
5	Scherer	Oil	Apr-12	0	0	0.00	-13	-2	153.85	1,296	177	136.57
6	Scherer	Oil	May-12	0	0	0.00	-159	-22	138.36	1,336	183	136.98
7	Scherer	Oil	Jun-12	0	0	0.00	38	5	131.58	1,353	184	135.99
8	Scherer	Oil	Jul-12	0	0	0.00	-16	-2	125.00	1,311	178	135.77
9	Scherer	Oil	Aug-12	0	0	0.00	-29	-4	137.93	1,313	180	137.09
10	Scherer	Oil	Sep-12	0	0	0.00	1	0	0.00	1,324	182	137.46
11	Scherer	Oil	Oct-12	0	0	0.00	-14	-2	142.86	1,395	193	138.35
12	Scherer	Oil	Nov-12	0	0	0.00	15	2	133.33	1,338	185	138.27
13	Scherer	Oil	Dec-12	0	0	0.00	-167	-23	137.72	1,246	172	138.04
14	Total									17,178	2,333	
15	Scherer	Oil	13 mth avg							1,321	179	135.50

16 Totals may not add due to rounding.

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide conventional fuel account balances in dollars and quantities for each fuel type for the test year and the two preceeding years. Include Natural Gas even though no inventory is carried. (Give units in Barrels, Tons, or MCF)

Type of Data Shown:

_____ Projected Test Year Ended 12/31/14

_____ Prior Year Ended 12/31/13

X Historical Year Ended 12/31/12

Witness: M. L. Burroughs, S. D. Ritenour

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
				Beginning Inventory			Receipts			Fuel Issued to Generation		
Line No.	Plant	Fuel Type	Month	Units	($000)	$/Unit	Units	($000)	$/Unit	Units	($000)	$/Unit
1	Smith	Nat. Gas	Dec-11	813,899	3,293	4.05	2,217,868	8,238	3.71	2,017,404	7,673	3.80
2	Smith	Nat. Gas	Jan-12	1,014,363	3,858	3.80	2,514,745	8,157	3.24	2,523,855	8,599	3.41
3	Smith	Nat. Gas	Feb-12	988,972	3,369	3.41	2,470,800	7,427	3.01	2,470,800	7,710	3.12
4	Smith	Nat. Gas	Mar-12	988,972	3,086	3.12	2,458,726	6,777	2.76	2,425,898	6,936	2.86
5	Smith	Nat. Gas	Apr-12	1,021,800	2,927	2.86	1,691,009	6,107	3.61	1,691,009	5,627	3.33
6	Smith	Nat. Gas	May-12	1,021,800	3,407	3.33	2,210,464	8,423	3.81	2,210,464	8,086	3.66
7	Smith	Nat. Gas	Jun-12	1,021,800	3,745	3.67	2,725,586	10,084	3.70	2,236,572	8,671	3.88
8	Smith	Nat. Gas	Jul-12	920,263	3,563	3.87	2,563,275	11,152	4.35	2,285,883	9,834	4.30
9	Smith	Nat. Gas	Aug-12	922,064	3,962	4.30	2,464,339	10,405	4.22	2,338,772	10,075	4.31
10	Smith	Nat. Gas	Sep-12	840,326	3,627	4.32	3,389,739	13,175	3.89	2,168,050	9,381	4.33
11	Smith	Nat. Gas	Oct-12	776,301	3,359	4.33	3,190,530	14,121	4.43	2,081,770	9,779	4.70
12	Smith	Nat. Gas	Nov-12	758,210	3,569	4.71	3,115,635	12,464	4.00	2,161,643	9,353	4.33
13	Smith	Nat. Gas	Dec-12	661,906	2,867	4.33	2,311,592	9,183	3.97	2,203,866	8,931	4.05

Supporting Schedules: Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide conventional fuel account balances in dollars and quantities for each fuel type for the test year and the two preceeding years. Include Natural Gas even though no inventory is carried. (Give units in Barrels, Tons, or MCF)

Type of Data Shown:

_____ Projected Test Year Ended 12/31/14

_____ Prior Year Ended 12/31/13

X Historical Year Ended 12/31/12

Witness: M. L. Burroughs, S. D. Ritenour

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
				Fuel Issues (Other)			Adjustments			Ending Inventory		
Line No.	Plant	Fuel Type	Month	Units	($000)	$/Unit	Units	($000)	$/Unit	Units	($000)	$/Unit
1	Smith	Nat. Gas	Dec-11	0	0	0.00	0	0	0.00	1,014,363	3,858	3.80
2	Smith	Nat. Gas	Jan-12	16,280	47	2.89	0	0	0.00	988,972	3,369	3.41
3	Smith	Nat. Gas	Feb-12	0	0	0.00	0	0	0.00	988,972	3,086	3.12
4	Smith	Nat. Gas	Mar-12	0	0	0.00	0	0	0.00	1,021,800	2,927	2.86
5	Smith	Nat. Gas	Apr-12	0	0	0.00	0	0	0.00	1,021,800	3,407	3.33
6	Smith	Nat. Gas	May-12	0	0	0.00	0	0	0.00	1,021,800	3,745	3.67
7	Smith	Nat. Gas	Jun-12	590,551	1,595	2.70	0	0	0.00	920,263	3,563	3.87
8	Smith	Nat. Gas	Jul-12	275,591	919	3.33	0	0	0.00	922,064	3,962	4.30
9	Smith	Nat. Gas	Aug-12	207,305	665	3.21	0	0	0.00	840,326	3,627	4.32
10	Smith	Nat. Gas	Sep-12	1,285,714	4,062	3.16	0	0	0.00	776,301	3,359	4.33
11	Smith	Nat. Gas	Oct-12	1,126,851	4,132	3.67	0	0	0.00	758,210	3,569	4.71
12	Smith	Nat. Gas	Nov-12	1,050,296	3,812	3.63	0	0	0.00	661,906	2,867	4.33
13	Smith	Nat. Gas	Dec-12	0	0	0.00	0	0	0.00	769,632	3,120	4.05
14	Total									11,706,409	44,459	
15	Smith	Nat. Gas	13 mth avg							900,493	3,420	3.80

16 Totals may not add due to rounding.

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide conventional fuel account balances in dollars and quantities for each fuel type for the test year and the two preceeding years. Include Natural Gas even though no inventory is carried. (Give units in Barrels, Tons, or MCF)

Type of Data Shown:

____ Projected Test Year Ended 12/31/14

____ Prior Year Ended 12/31/13

X Historical Year Ended 12/31/12

Witness: M. L. Burroughs, S. D. Ritenour

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
				Beginning Inventory			Receipts			Fuel Issued to Generation		
Line No.	Plant	Fuel Type	Month	Units	($000)	$/Unit	Units	($000)	$/Unit	Units	($000)	$/Unit
1	Crist	Nat. Gas	Dec-11	0	0	0.00	9,002	122	13.55	9,002	122	13.55
2	Crist	Nat. Gas	Jan-12	0	0	0.00	252,581	756	2.99	252,581	756	2.99
3	Crist	Nat. Gas	Feb-12	0	0	0.00	534,631	1,530	2.86	534,631	1,530	2.86
4	Crist	Nat. Gas	Mar-12	0	0	0.00	600,768	1,498	2.49	600,768	1,498	2.49
5	Crist	Nat. Gas	Apr-12	0	0	0.00	554,975	1,282	2.31	554,975	1,282	2.31
6	Crist	Nat. Gas	May-12	0	0	0.00	444,340	1,283	2.89	444,340	1,283	2.89
7	Crist	Nat. Gas	Jun-12	0	0	0.00	425,770	1,235	2.90	425,770	1,235	2.90
8	Crist	Nat. Gas	Jul-12	0	0	0.00	585,265	1,940	3.31	585,265	1,940	3.31
9	Crist	Nat. Gas	Aug-12	0	0	0.00	395,567	1,330	3.36	395,567	1,330	3.36
10	Crist	Nat. Gas	Sep-12	0	0	0.00	4,982	119	23.89	4,982	119	23.89
11	Crist	Nat. Gas	Oct-12	0	0	0.00	3,871	126	32.55	3,871	126	32.55
12	Crist	Nat. Gas	Nov-12	0	0	0.00	129,264	601	4.65	129,264	601	4.65
13	Crist	Nat. Gas	Dec-12	0	0	0.00	139,646	581	4.16	139,646	581	4.16

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide conventional fuel account balances in dollars and quantities for each fuel type for the test year and the two preceeding years. Include Natural Gas even though no inventory is carried. (Give units in Barrels, Tons, or MCF)

Type of Data Shown:

_____ Projected Test Year Ended 12/31/14

_____ Prior Year Ended 12/31/13

X Historical Year Ended 12/31/12

Witness: M. L. Burroughs, S. D. Ritenour

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
				Fuel Issues (Other)			Adjustments			Ending Inventory		
Line No.	Plant	Fuel Type	Month	Units	($000)	$/Unit	Units	($000)	$/Unit	Units	($000)	$/Unit
1	Crist	Nat. Gas	Dec-11	0	0	0.00	0	0	0.00	0	0	0.00
2	Crist	Nat. Gas	Jan-12	0	0	0.00	0	0	0.00	0	0	0.00
3	Crist	Nat. Gas	Feb-12	0	0	0.00	0	0	0.00	0	0	0.00
4	Crist	Nat. Gas	Mar-12	0	0	0.00	0	0	0.00	0	0	0.00
5	Crist	Nat. Gas	Apr-12	0	0	0.00	0	0	0.00	0	0	0.00
6	Crist	Nat. Gas	May-12	0	0	0.00	0	0	0.00	0	0	0.00
7	Crist	Nat. Gas	Jun-12	0	0	0.00	0	0	0.00	0	0	0.00
8	Crist	Nat. Gas	Jul-12	0	0	0.00	0	0	0.00	0	0	0.00
9	Crist	Nat. Gas	Aug-12	0	0	0.00	0	0	0.00	0	0	0.00
10	Crist	Nat. Gas	Sep-12	0	0	0.00	0	0	0.00	0	0	0.00
11	Crist	Nat. Gas	Oct-12	0	0	0.00	0	0	0.00	0	0	0.00
12	Crist	Nat. Gas	Nov-12	0	0	0.00	0	0	0.00	0	0	0.00
13	Crist	Nat. Gas	Dec-12	0	0	0.00	0	0	0.00	0	0	0.00
14	Total									0	0	
15	Crist	Nat. Gas	13 mth avg							0	0	0.00

16 Totals may not add due to rounding.

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide conventional fuel account balances in dollars and quantities for each fuel type for the test year and the two preceeding years. Include Natural Gas even though no inventory is carried. (Give units in Barrels, Tons, or MCF)

Type of Data Shown:

_____ Projected Test Year Ended 12/31/14

_____ Prior Year Ended 12/31/13

X Historical Year Ended 12/31/12

Witness: M. L. Burroughs, S. D. Ritenour

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
				Beginning Inventory			Receipts			Fuel Issued to Generation		
Line No.	Plant	Fuel Type	Month	Units	($000)	$/Unit	Units	($000)	$/Unit	Units	($000)	$/Unit
1	Baconton	Nat. Gas	Dec-11	0	0	0.00	2,419	22	9.09	2,419	22	9.09
2	Baconton	Nat. Gas	Jan-12	0	0	0.00	60,375	190	3.15	60,375	190	3.15
3	Baconton	Nat. Gas	Feb-12	0	0	0.00	52,730	148	2.81	52,730	148	2.81
4	Baconton	Nat. Gas	Mar-12	0	0	0.00	292	2	6.85	292	2	6.85
5	Baconton	Nat. Gas	Apr-12	0	0	0.00	141,364	318	2.25	141,364	318	2.25
6	Baconton	Nat. Gas	May-12	0	0	0.00	8,518	43	5.05	8,518	43	5.05
7	Baconton	Nat. Gas	Jun-12	0	0	0.00	300,962	863	2.87	300,962	863	2.87
8	Baconton	Nat. Gas	Jul-12	0	0	0.00	460,612	1,529	3.32	460,612	1,529	3.32
9	Baconton	Nat. Gas	Aug-12	0	0	0.00	367,364	1,183	3.22	367,364	1,183	3.22
10	Baconton	Nat. Gas	Sep-12	0	0	0.00	226,407	693	3.06	226,407	693	3.06
11	Baconton	Nat. Gas	Oct-12	0	0	0.00	127,596	448	3.51	127,596	448	3.51
12	Baconton	Nat. Gas	Nov-12	0	0	0.00	137,119	537	3.92	137,119	537	3.92
13	Baconton	Nat. Gas	Dec-12	0	0	0.00	81,062	310	3.82	81,062	310	3.82

14 Note: Gulf provides the fuel to operate these units per the Purchase Power Agreement.

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide conventional fuel account balances in dollars and quantities for each fuel type for the test year and the two preceeding years. Include Natural Gas even though no inventory is carried. (Give units in Barrels, Tons, or MCF)

Type of Data Shown:
____ Projected Test Year Ended 12/31/14
____ Prior Year Ended 12/31/13
X Historical Year Ended 12/31/12
Witness: M. L. Burroughs, S. D. Ritenour

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
				Fuel Issues (Other)			Adjustments			Ending Inventory		
Line No.	Plant	Fuel Type	Month	Units	($000)	$/Unit	Units	($000)	$/Unit	Units	($000)	$/Unit
1	Baconton	Nat. Gas	Dec-11	0	0	0.00	0	0	0.00	0	0	0.00
2	Baconton	Nat. Gas	Jan-12	0	0	0.00	0	0	0.00	0	0	0.00
3	Baconton	Nat. Gas	Feb-12	0	0	0.00	0	0	0.00	0	0	0.00
4	Baconton	Nat. Gas	Mar-12	0	0	0.00	0	0	0.00	0	0	0.00
5	Baconton	Nat. Gas	Apr-12	0	0	0.00	0	0	0.00	0	0	0.00
6	Baconton	Nat. Gas	May-12	0	0	0.00	0	0	0.00	0	0	0.00
7	Baconton	Nat. Gas	Jun-12	0	0	0.00	0	0	0.00	0	0	0.00
8	Baconton	Nat. Gas	Jul-12	0	0	0.00	0	0	0.00	0	0	0.00
9	Baconton	Nat. Gas	Aug-12	0	0	0.00	0	0	0.00	0	0	0.00
10	Baconton	Nat. Gas	Sep-12	0	0	0.00	0	0	0.00	0	0	0.00
11	Baconton	Nat. Gas	Oct-12	0	0	0.00	0	0	0.00	0	0	0.00
12	Baconton	Nat. Gas	Nov-12	0	0	0.00	0	0	0.00	0	0	0.00
13	Baconton	Nat. Gas	Dec-12	0	0	0.00	0	0	0.00	0	0	0.00
14	Total									0	0	
15	Baconton	Nat. Gas	13 mth avg							0	0	0.00

16 Note: Gulf provides the fuel to operate these units per the Purchase Power Agreement.
17 Totals may not add due to rounding.

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide conventional fuel account balances in dollars and quantities for each fuel type for the test year and the two preceeding years. Include Natural Gas even though no inventory is carried. (Give units in Barrels, Tons, or MCF)

Type of Data Shown:

____ Projected Test Year Ended 12/31/14

____ Prior Year Ended 12/31/13

X Historical Year Ended 12/31/12

Witness: M. L. Burroughs, S. D. Ritenour

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
				Beginning Inventory			Receipts			Fuel Issued to Generation		
Line No.	Plant	Fuel Type	Month	Units	($000)	$/Unit	Units	($000)	$/Unit	Units	($000)	$/Unit
1	Dahlberg	Nat. Gas	Dec-11	0	0	0.00	7,778	28	3.60	7,778	28	3.60
2	Dahlberg	Nat. Gas	Jan-12	0	0	0.00	85	23	270.59	85	23	270.59
3	Dahlberg	Nat. Gas	Feb-12	0	0	0.00	29	22	758.62	29	22	758.62
4	Dahlberg	Nat. Gas	Mar-12	0	0	0.00	18	6	333.33	18	6	333.33
5	Dahlberg	Nat. Gas	Apr-12	0	0	0.00	13	0	0.00	13	0	0.00
6	Dahlberg	Nat. Gas	May-12	0	0	0.00	15,188	84	5.53	15,188	84	5.53
7	Dahlberg	Nat. Gas	Jun-12	0	0	0.00	156,056	475	3.04	156,056	475	3.04
8	Dahlberg	Nat. Gas	Jul-12	0	0	0.00	367,778	1,191	3.24	367,778	1,191	3.24
9	Dahlberg	Nat. Gas	Aug-12	0	0	0.00	89,260	359	4.02	89,260	359	4.02
10	Dahlberg	Nat. Gas	Sep-12	0	0	0.00	48,091	187	3.89	48,091	187	3.89
11	Dahlberg	Nat. Gas	Oct-12	0	0	0.00	1,106	6	5.42	1,106	6	5.42
12	Dahlberg	Nat. Gas	Nov-12	0	0	0.00	51,199	185	3.61	51,199	185	3.61
13	Dahlberg	Nat. Gas	Dec-12	0	0	0.00	410	1	2.44	410	1	2.44

14 Note: Gulf provides the fuel to operate these units per the Purchase Power Agreement.

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide conventional fuel account balances in dollars and quantities for each fuel type for the test year and the two preceeding years. Include Natural Gas even though no inventory is carried. (Give units in Barrels, Tons, or MCF)

Type of Data Shown:

_____ Projected Test Year Ended 12/31/14

_____ Prior Year Ended 12/31/13

X Historical Year Ended 12/31/12

Witness: M. L. Burroughs, S. D. Ritenour

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
				Fuel Issues (Other)			Adjustments			Ending Inventory		
Line No.	Plant	Fuel Type	Month	Units	($000)	$/Unit	Units	($000)	$/Unit	Units	($000)	$/Unit
1	Dahlberg	Nat. Gas	Dec-11	0	0	0.00	0	0	0.00	0	0	0.00
2	Dahlberg	Nat. Gas	Jan-12	0	0	0.00	0	0	0.00	0	0	0.00
3	Dahlberg	Nat. Gas	Feb-12	0	0	0.00	0	0	0.00	0	0	0.00
4	Dahlberg	Nat. Gas	Mar-12	0	0	0.00	0	0	0.00	0	0	0.00
5	Dahlberg	Nat. Gas	Apr-12	0	0	0.00	0	0	0.00	0	0	0.00
6	Dahlberg	Nat. Gas	May-12	0	0	0.00	0	0	0.00	0	0	0.00
7	Dahlberg	Nat. Gas	Jun-12	0	0	0.00	0	0	0.00	0	0	0.00
8	Dahlberg	Nat. Gas	Jul-12	0	0	0.00	0	0	0.00	0	0	0.00
9	Dahlberg	Nat. Gas	Aug-12	0	0	0.00	0	0	0.00	0	0	0.00
10	Dahlberg	Nat. Gas	Sep-12	0	0	0.00	0	0	0.00	0	0	0.00
11	Dahlberg	Nat. Gas	Oct-12	0	0	0.00	0	0	0.00	0	0	0.00
12	Dahlberg	Nat. Gas	Nov-12	0	0	0.00	0	0	0.00	0	0	0.00
13	Dahlberg	Nat. Gas	Dec-12	0	0	0.00	0	0	0.00	0	0	0.00
14	Total									0	0	
15	Dahlberg	Nat. Gas	13 mth avg							0	0	0.00

16 Note: Gulf provides the fuel to operate these units per the Purchase Power Agreement.

17 Totals may not add due to rounding.

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide conventional fuel account balances in dollars and quantities for each fuel type for the test year and the two preceeding years. Include Natural Gas even though no inventory is carried. (Give units in Barrels, Tons, or MCF)

Type of Data Shown:

_____ Projected Test Year Ended 12/31/14

_____ Prior Year Ended 12/31/13

X Historical Year Ended 12/31/12

Witness: M. L. Burroughs, S. D. Ritenour

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
				Beginning Inventory			Receipts			Fuel Issued to Generation		
Line No.	Plant	Fuel Type	Month	Units	($000)	$/Unit	Units	($000)	$/Unit	Units	($000)	$/Unit
1	Cent. AL	Nat. Gas	Dec-11	0	0	0.00	2,993,914	10,041	3.35	2,993,914	10,041	3.35
2	Cent. AL	Nat. Gas	Jan-12	0	0	0.00	3,468,715	10,385	2.99	3,468,715	10,385	2.99
3	Cent. AL	Nat. Gas	Feb-12	0	0	0.00	3,674,934	10,126	2.76	3,674,934	10,126	2.76
4	Cent. AL	Nat. Gas	Mar-12	0	0	0.00	4,035,207	9,095	2.25	4,035,207	9,095	2.25
5	Cent. AL	Nat. Gas	Apr-12	0	0	0.00	2,309,924	4,970	2.15	2,309,924	4,970	2.15
6	Cent. AL	Nat. Gas	May-12	0	0	0.00	3,802,760	9,853	2.59	3,802,760	9,853	2.59
7	Cent. AL	Nat. Gas	Jun-12	0	0	0.00	3,939,254	10,178	2.58	3,939,254	10,178	2.58
8	Cent. AL	Nat. Gas	Jul-12	0	0	0.00	4,137,255	12,902	3.12	4,137,255	12,902	3.12
9	Cent. AL	Nat. Gas	Aug-12	0	0	0.00	4,171,687	12,559	3.01	4,171,687	12,559	3.01
10	Cent. AL	Nat. Gas	Sep-12	0	0	0.00	3,796,331	11,346	2.99	3,796,331	11,346	2.99
11	Cent. AL	Nat. Gas	Oct-12	0	0	0.00	2,623,703	9,019	3.44	2,623,703	9,019	3.44
12	Cent. AL	Nat. Gas	Nov-12	0	0	0.00	2,926,641	12,452	4.25	2,926,641	12,452	4.25
13	Cent. AL	Nat. Gas	Dec-12	0	0	0.00	3,901,194	15,171	3.89	3,901,194	15,171	3.89

14 Note: Gulf provides the fuel to operate these units per the Purchase Power Agreement.

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide conventional fuel account balances in dollars and quantities for each fuel type for the test year and the two preceeding years. Include Natural Gas even though no inventory is carried. (Give units in Barrels, Tons, or MCF)

Type of Data Shown:

____ Projected Test Year Ended 12/31/14

____ Prior Year Ended 12/31/13

X Historical Year Ended 12/31/12

Witness: M. L. Burroughs, S. D. Ritenour

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
				Fuel Issues (Other)			Adjustments			Ending Inventory		
Line No.	Plant	Fuel Type	Month	Units	($000)	$/Unit	Units	($000)	$/Unit	Units	($000)	$/Unit
1	Cent. AL	Nat. Gas	Dec-11	0	0	0.00	0	0	0.00	0	0	0.00
2	Cent. AL	Nat. Gas	Jan-12	0	0	0.00	0	0	0.00	0	0	0.00
3	Cent. AL	Nat. Gas	Feb-12	0	0	0.00	0	0	0.00	0	0	0.00
4	Cent. AL	Nat. Gas	Mar-12	0	0	0.00	0	0	0.00	0	0	0.00
5	Cent. AL	Nat. Gas	Apr-12	0	0	0.00	0	0	0.00	0	0	0.00
6	Cent. AL	Nat. Gas	May-12	0	0	0.00	0	0	0.00	0	0	0.00
7	Cent. AL	Nat. Gas	Jun-12	0	0	0.00	0	0	0.00	0	0	0.00
8	Cent. AL	Nat. Gas	Jul-12	0	0	0.00	0	0	0.00	0	0	0.00
9	Cent. AL	Nat. Gas	Aug-12	0	0	0.00	0	0	0.00	0	0	0.00
10	Cent. AL	Nat. Gas	Sep-12	0	0	0.00	0	0	0.00	0	0	0.00
11	Cent. AL	Nat. Gas	Oct-12	0	0	0.00	0	0	0.00	0	0	0.00
12	Cent. AL	Nat. Gas	Nov-12	0	0	0.00	0	0	0.00	0	0	0.00
13	Cent. AL	Nat. Gas	Dec-12	0	0	0.00	0	0	0.00	0	0	0.00
14	Total									0	0	
15	Cent. AL	Nat. Gas	13 mth avg							0	0	0.00

16 Note: Gulf provides the fuel to operate these units per the Purchase Power Agreement.

17 Totals may not add due to rounding.

Supporting Schedules:

Recap Schedules:

SCHEDULE B-19 | MISCELLANEOUS DEFERRED DEBITS | Page 1 of 1

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide a schedule showing the following information for miscellaneous deferred debits for the test year. Minor items less than 5% of the account total, or amounts less than $10,000, whichever is greater, may be grouped by classes.

Type of Data Shown:
X Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
___ Historical Year Ended 12/31/12
Witness: S. D. Ritenour

(000's)

(1) LINE NO.	(2) DESCRIPTION	(3) BALANCE AT BEGINNING OF YEAR	(4) DEBITS	(5) CREDITS ACCOUNT	(6) CREDITS AMOUNT	(7) BALANCE AT END OF YEAR
1	Purchase Power Agreements	7,502	0	254	7,502	0
2	Site Acquisition Costs - North Escambia	149	0	Various	0	149
3	Customer Job Orders	1,270	0	Various	0	1,270
4	Total Deferred Debits	8,921	0		7,502	1,419

199

Supporting Schedules:

Recap Schedule: B-3

SCHEDULE B-20 | OTHER DEFERRED CREDITS | Page 1 of 1

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide a schedule showing the following information for other deferred credits for the test year. Minor items less than 5% of the account total, or amounts less than $10,000, whichever is greater, may be grouped by classes.

Type of Data Shown:
X Projected Test Year Ended 12/31/14
__ Prior Year Ended 12/31/13
__ Historical Year Ended 12/31/12
Witness: S. D. Ritenour

(000's)

(1) LINE NO.	(2) DESCRIPTION	(3) BALANCE AT BEGINNING OF YEAR	(4) DEBITS CONTRA ACCOUNTS	(5) DEBITS AMOUNT	(6) CREDITS	(7) BALANCE AT END OF YEAR
1	Other Deferred Credits - Misc	8,039	Various	403	0	7,636
2	Purchase Power Agreements	180,149	182	0	4,916	185,065
3	Environmental Liability	59,461	182	1,377	0	58,084
4	Total Deferred Credits	247,649		1,780	4,916	250,785

200

Supporting Schedules:

Recap Schedules: B-3

ACCUMULATED PROVISION ACCOUNTS

Schedule B-21 — 228.1, 228.2, and 228.4 —

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide a schedule of the amounts charged to operating expenses, and the amounts accrued and charged to the provision account balances, for the last calendar year and test year. Indicate desired reserve balances and basis for determining the desired balances.

Type of Data Shown:
X Projected Test Year Ended 12/31/14
_ Prior Year Ended 12/31/13
_ Historical Year Ended 12/31/12
Witness: C. J. Erickson

($000's)

(1) Line No.		(2) Year	(3) Balance Beginning of Period	(4) Current Year Accrual		(5) Amount Charged to Reserve	(6) Net Fund Income After Taxes	(7) Reserve Balance End of Period	(8) Description of Charge	(9) Charged to Operating Expenses
1	Account 228.1	2014	35,094	3,500	Note 1	319	-	38,715	Interest earned on the	3,500
2	Property Insurance								funded portion of the	
3									property insurance reserve.	
4						(440)	-		Estimate based on historical.	
5	FPSC Order No. PSC-12-0179-FOF-EI, Docket No. 110138-EI, issued April 3, 2012, authorized the Company to continue its $3.5 million annual									
6	accrual with a target level of $48 million to $55 million. Additional accruals are authorized above the $3.5 million at the Company's discretion.									
7	The original accrual was approved in FPSC Order No. PSC-96-1334-FOF-EI, Docket No. 951433-EI, issued November 5, 1996.									
8	Account 228.2	2014	3,256	1,600						1,600
9	Injuries & Damages					1,405	-	3,451	Estimate based on historical.	
10	The desired reserve balance is to provide adequate coverage for normal charges and estimated liabilities.									
11	Estimated workers' compensation liabilities are based on an actuarial study.									
12	Estimated legal liabilities are determined on a case by case basis.									
13	FPSC Order No. PSC-04-0453-PAA-EI, Docket No. 040218-EI, issued May 3, 2004, authorized the Company to increase its annual I&D									
14	accrual to $1.6 million. Additional accruals are authorized above the $1.6 million at the Company's discretion to the extent the balance									
15	in the reserve does not exceed $2 million.									
16	Note 1 - This amount in column (4) does not reflect the $5.5 million NOI adjustment presented in column (6) page 2 of 2 MFR C-38.									

Supporting Schedules:

Recap Schedules:

ACCUMULATED PROVISION ACCOUNTS
228.1, 228.2, and 228.4

Schedule B-21

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide a schedule of the amounts charged to operating expenses, and the amounts accrued and charged to the provision account balances, for the last calendar year and test year. Indicate desired reserve balances and basis for determining the desired balances.

Type of Data Shown:
_ Projected Test Year Ended 12/31/14
_ Prior Year Ended 12/31/13
X Historical Year Ended 12/31/12
Witness: C. J. Erickson

($000's)

(1) Line No.	(2) Year	(3) Balance Beginning of Period	(4) Current Year Accrual	(5) Amount Charged to Reserve	(6) Net Fund Income After Taxes	(7) Reserve Balance End of Period	(8) Description of Charge	(9) Charged to Operating Expenses
1 Account 228.1 Property Insurance	2012	30,473	3,500	2,017	-	31,956	Charges for storm restoration and interest earned on the funded portion of the property insurance reserve.	3,500

4 FPSC Order No. PSC-12-0179-FOF-EI, Docket No. 110138-EI, issued April 3, 2012, authorized the Company to continue its $3.5 million annual
5 accrual with a target level of $48 million to $55 million. Additional accruals are authorized above the $3.5 million at the Company's discretion.
6 The original accrual was approved in FPSC Order No. PSC-96-1334-FOF-EI, Docket No. 951433-EI, issued November 5, 1996.

7 Account 228.2 Injuries & Damages	2012	2,740	1,600	1,279	-	3,061	Charges for worker's compensation payments, general liability payments and automobile damages.	1,600

11 The desired reserve balance is to provide adequate coverage for normal charges and estimated liabilities.
12 Estimated workers' compensation liabilities are based on an actuarial study.
13 Estimated legal liabilities are determined on a case by case basis.

14 FPSC Order No. PSC-04-0453-PAA-EI, Docket No. 040218-EI, issued May 3, 2004, authorized the Company to increase its annual I&D
15 accrual to $1.6 million. Additional accruals are authorized above the $1.6 million at the Company's discretion to the extent the balance
16 in the reserve does not exceed $2 million.

Supporting Schedules:

Recap Schedules:

Schedule B-22 | TOTAL ACCUMULATED DEFERRED INCOME TAXES | Page 1 of 1

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: For each of the accumulated deferred income tax accounts (Nos. 190, 281, 282, 283), provide annual balances beginning with the historical base year in the last rate case and ending with the end of the test year.

(000's)

Type of Data Shown:
X Projected Test Year Ended 12/31/14
X Prior Year Ended 12/31/13
X Historical Year Ended 12/31/10 - 12/31/12
Witness: C. J. Erickson

(1) Line No.	(2) Annual Period	(3) Acct 190 Accumulated Deferred Income Taxes Dr(Cr)	(4) Acct 281 Accumulated Deferred Income Taxes Dr(Cr)	(5) Acct 282 Accumulated Deferred Income Taxes Dr(Cr)	(6) Acct 283 Accumulated Deferred Income Taxes Dr(Cr)	(7) Net Accumulated Deferred Income Taxes Dr(Cr)
1	2010	70,410	(57,375)	(347,381)	(54,734)	(389,080)
2	2011	72,725	(78,392)	(406,744)	(57,848)	(470,259)
3	2012	76,219	(141,628)	(518,939)	(62,632)	(646,980)
4	2013	74,155	(161,104)	(549,275)	(57,760)	(693,984)
5	2014	79,075	(181,679)	(561,419)	(55,936)	(719,959)

Supporting Schedules:

Recap Schedules:

Schedule B-23 | INVESTMENT TAX CREDITS - ANNUAL ANALYSIS | Page 1 of 1

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide an analysis of accumulated investment tax credits generated and amortization of investment tax credits on an annual basis beginning with the historical base year in the last rate case and ending with the end of the test year.

(000's)

Type of Data Shown:
X Projected Test Year Ended 12/31/14
X Prior Year Ended 12/31/13
X Historical Year Ended 12/31/10 - 12/31/12
Witness: C. J. Erickson

(1) Line No.	(2) Annual Period	(3) Beginning Balance	(4) Amortization	(5) Ending Balance
1	2010	(9,652)	1,543	(8,109)
2	2011	(8,109)	1,349	(6,760)
3	2012	(6,760)	1,352	(5,408)
4	2013	(5,408)	1,302	(4,106)
5	2014	(4,106)	1,226	(2,880)

Supporting Schedules:

Recap Schedules:

Schedule B-24 | LEASING ARRANGEMENTS | Page 1 of 1

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide the data specified for leasing arrangements in effect during the test year and prior year.

(000's)

Type of Data Shown:
X Projected Test Year Ended 12/31/14
X Prior Year Ended 12/31/13
___ Historical Year Ended 12/31/12
Witness: C. J. Erickson

Leasing Payments for prior year:	$18,930
Leasing Payments for test year:	$17,481
Leasing Payments, Remaining Life Contracts	$3,349

Describe Leasing Agreements Whose Lifetime Costs Exceed $10 Million

(1) Line No.	(2) Asset	(3) Original Cost	(4) Average Annual Payment (A)	(5) Life of Contract	(6) Disposition of Asset, Provision for Purchase
1	1994 Aluminum Coal Cars	$7,047	$536	22 Years	Option to purchase after three years; purchase price shall be equal to the greater of the applicable termination value in the contract or the fair market value.
5	2009 Coal Barges	$13,950	$3,487	5 Years	No purchase option exists.
6	2010 Tow Boats	$13,200	$7,699	5 Years	No purchase option exists.

(A) Lease payments are recovered through the Fuel Adjustment Clause. The "Average Annual Payment" is the average for the remaining life of the contract.

Supporting Schedules: Recap Schedules:

SCHEDULE B-25	ACCOUNTING POLICY CHANGES AFFECTING RATE BASE	Page 1 of 1
FLORIDA PUBLIC SERVICE COMMISSION	EXPLANATION: Provide a statement of changes in accounting policy for the test year and the prior year. If appropriate, explain any changes in accounting procedures for the projected test year and the effect, if any, of the use of a non-calendar test year.	Type of data shown: X Projected Test Year Ended 12/31/14 X Prior Year Ended 12/31/13 ___ Historical Year Ended 12/31/12
COMPANY: GULF POWER COMPANY		
DOCKET NO.: 130140-EI		Witness: C. J. Erickson, S. D. Ritenour

Line No.	
1	There are no accounting policy changes affecting rate base for the prior year or test year.

Supporting Schedules:

Recap Schedules:

FILED JUL 12, 2013
DOCUMENT NO. 03976-13
FPSC - COMMISSION CLERK

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 130140-EI

GULF POWER

A SOUTHERN COMPANY

MINIMUM FILING REQUIREMENTS

SECTION C – NET OPERATING INCOME SCHEDULES

GULF POWER COMPANY

Docket No. 130140-EI
Minimum Filing Requirements

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GULF POWER COMPANY

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Minimum Filing Requirements

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GULF POWER COMPANY

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GULF POWER COMPANY

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Minimum Filing Requirements

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Schedule C-1 | ADJUSTED JURISDICTIONAL NET OPERATING INCOME | Page 1 of 3

FLORIDA PUBLIC SERVICE COMMISSION

EXPLANATION: Provide the calculation of the jurisdictional net operating income for the test year, the prior year and the most recent historical year.

Type of Data Shown:
X Projected Tes Year Ended 12/31/14
___Prior Year Ended 12/31/13
___His orical Year Ended 12/31/12

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

($000's)

Wi ness: S. D. Ritenour

Adjusted Jurisdictional Net Operating Income Calculation for the Twelve Months Ended

(1) Line No.	(2) Description	(3)	(4) Total Company per Books	(5) Non-Electric Utility	(6) Electric Utility (4) - (5)	(7) Commission Adjustments (Sch. C-3)	(8) Utility Adjusted per Commission (6) + (7)	(9) Company Adjustments (Sch. C-3)	(10) Total Adjusted Utility (8) + (9)	(11) Unit Power Sales Net Operating Income	(12) Total Adjusted Utility net of UPS (10) - (11)	(13) Jurisdictional Separation Factor	(14) Jurisdictional Amount (12) x (13)
1	Operating Revenues:												
2	Sales of Electricity		1,503,274	-	1,503,274	(926,938)	576,336	-	576,336	(58,261)	518,075	0.9759591	505,620
3	Other Operating Revenues		69,171	-	69,171	(42,247)	26,924	-	26,924	-	26,924	0.8554078	23,031
4	Total Operating Revenues		1,572,445	-	1,572,445	(969,185)	603,260	-	603,260	(58,261)	544,999	0.9700036	528,651
5	Operating Expenses:												
6	Recoverable Fuel		650,274	-	650,274	(650,274)	-	-	-	-	-		-
7	Recoverable Capacity		65,247	-	65,247	(65,247)	-	-	-	-	-		-
8	Recoverable Conservation		23,520	-	23,520	(23,520)	-	-	-	-	-		-
9	Recoverable Environmental		29,077	-	29,077	(29,077)	-	-	-	-	-		-
10	Other Operation & Maintenance		305,462	-	305,462	(851)	304,611	3,997	308,608	(12,692)	295,916	0.9806803	290,199
11	Depreciation & Amortization		156,353	-	156,353	(41,333)	115,020	(618)	114,402	(7,975)	106,427	0.9819407	104,505
12	Amortization of Investment Credit		(1,224)	-	(1,224)	-	(1,224)	-	(1,224)	330	(894)	0.9821029	(878)
13	Taxes Other Than Income Taxes		111,773	-	111,773	(77,974)	33,799	(58)	33,741	(1,119)	32,622	0.9783888	31,917
14	Income Taxes												
15	Federal		46,880	-	46,880	(20,823)	26,057	(1,098)	24,959	(8,526)	16,433	0.9038265	14,852
16	State		1,934	-	1,934	(3,463)	(1,529)	(183)	(1,712)	(354)	(2,066)	0.9038265	(1,867)
17	Deferred Income Taxes - Net												
18	Federal		10,764	-	10,764	-	10,764	-	10,764	(1,958)	8,806	0.9038265	7,959
19	State		7,590	-	7,590	-	7,590	-	7,590	(1,389)	6,201	0.9038265	5,605
20	Total Operating Expenses		1,407,650	-	1,407,650	(912,562)	495,088	2,040	497,128	(33,683)	463,445	0.9759346	452,292
21	Net Operating Income		164,795	-	164,795	(56,623)	108,172	(2,040)	106,132	(24,578)	81,554	0.9362999	76,359

Supporting Schedules: C-2, C-3, C-4, C-5, C-20, C-22, F-8

Recap Schedules: A-1, C-21

Schedule C-1 | ADJUSTED JURISDICTIONAL NET OPERATING INCOME | Page 2 of 3

FLORIDA PUBLIC SERVICE COMMISSION

EXPLANATION: Provide the calculation of the jurisdictional net operating income for the test year, the prior year and the most recent historical year.

Type of Data Shown:
____Projected Test Year Ended 12/31/14
_X_Prior Year Ended 12/31/13
____Historical Year Ended 12/31/12

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

($000's)

Witness: S. D. Ritenour

Adjusted Jurisdictional Net Operating Income Calculation for the Twelve Months Ended

(1) Line No.	(2) Description	(3)	(4) Total Company per Books	(5) Non-Electric Utility	(6) Electric Utility (4) - (5)	(7) Commission Adjustments (Sch. C-3)	(8) Utility Adjusted per Commission (6) + (7)	(9) Company Adjustments (Sch. C-3)	(10) Total Adjusted Utility (8) + (9)	(11) Unit Power Sales Net Operating Income	(12) Total Adjusted Utility net of UPS (10) - (11)	(13) Jurisdictional Separation Factor	(14) Jurisdictional Amount (12) x (13)
1	Operating Revenues:												
2	Sales of Electricity		1,415,038	-	1,415,038	(843,616)	571,422	-	571,422	(58,195)	513,227	0.9777175	501,791
3	Other Operating Revenues		92,702	-	92,702	(66,392)	26,310	-	26,310	-	26,310	0.8541239	22,472
4	Total Operating Revenues		1,507,740	-	1,507,740	(910,008)	597,732	-	597,732	(58,195)	539,537	0.9716905	524,263
5	Operating Expenses:												
6	Recoverable Fuel		619,107	-	619,107	(619,107)	-	-	-	-	-		-
7	Recoverable Capacity		48,423	-	48,423	(48,423)	-	-	-	-	-		-
8	Recoverable Conservation		23,262	-	23,262	(23,262)	-	-	-	-	-		-
9	Recoverable Environmental		24,999	-	24,999	(24,999)	-	-	-	-	-		-
10	Other Operation & Maintenance		281,458	-	281,458	(832)	280,626	-	280,626	(12,497)	268,129	0.9806803	262,949
11	Depreciation & Amortization		151,531	-	151,531	(41,100)	110,431	-	110,431	(7,806)	102,625	0.9819407	100,772
12	Amortization of Investment Credit		(1,304)	-	(1,304)	-	(1,304)	-	(1,304)	330	(974)	0.9821029	(956)
13	Taxes Other Than Income Taxes		103,988	-	103,988	(71,741)	32,247	-	32,247	(1,179)	31,068	0.9783700	30,396
14	Income Taxes												
15	Federal		30,762	-	30,762	(20,983)	9,779	-	9,779	(4,918)	4,861	0.9319821	4,530
16	State		3,022	-	3,022	(3,489)	(467)	-	(467)	(487)	(954)	0.9319821	(889)
17	Deferred Income Taxes - Net												
18	Federal		35,314	-	35,314	-	35,314	-	35,314	(5,645)	29,669	0.9319821	27,651
19	State		7,878	-	7,878	-	7,878	-	7,878	(1,270)	6,608	0.9319821	6,159
20	Total Operating Expenses		1,328,440	-	1,328,440	(853,936)	474,504	-	474,504	(33,472)	441,032	0.9763731	430,612
21	Net Operating Income		179,300	-	179,300	(56,072)	123,228	-	123,228	(24,723)	98,505	0.9507257	93,651

Supporting Schedules: C-2, C-3, C-4, C-5, C-20, C-22, F-8

Recap Schedules: A-1, C-21

Schedule C-1 | ADJUSTED JURISDICTIONAL NET OPERATING INCOME | Page 3 of 3

FLORIDA PUBLIC SERVICE COMMISSION

EXPLANATION: Provide the calculation of the jurisdictional net operating income for the test year, the prior year and the most recent historical year.

Type of Data Shown:
____Projected Test Year Ended 12/31/14
____Pr or Year Ended 12/31/13
_X_Historical Year Ended 12/31/12

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

($000's)

Witness: S. D. Ritenour

Adjusted Jurisdictional Net Operating Income Calculation for the Twelve Months Ended

(1) Line No.	(2) Description	(3)	(4) Total Company per Books	(5) Non-Electric Utility	(6) Electric Utility (4) - (5)	(7) Commission Adjustments (Sch. C-3)	(8) Utility Adjusted per Commission (6) + (7)	(9) Company Adjustments (Sch. C-3)	(10) Total Adjusted Utility (8) + (9)	(11) Unit Power Sales Net Operating Income	(12) Total Adjusted Utility net of UPS (10) - (11)	(13) Jurisdictional Separation Factor	(14) Jurisdictional Amount (12) x (13)
1	Operating Revenues:												
2	Sales of Electricity		1,363,071	-	1,363,071	(810,791)	552,280	-	552,280	(59,245)	493,035	0.9754561	480,934
3	Other Operating Revenues		76,825	-	76,825	(48,437)	28,388	-	28,388	-	28,388	0.8675849	24,629
4	Total Operating Revenues		1,439,896	-	1,439,896	(859,228)	580,668	-	580,668	(59,245)	521,423	0.9695832	505,563
5	Operating Expenses:												
6	Recoverable Fuel		572,512	-	572,512	(572,512)	-	-	-	-	-		-
7	Recoverable Capacity		45,500	-	45,500	(45,500)	-	-	-	-	-		-
8	Recoverable Conservation		20,910	-	20,910	(20,910)	-	-	-	-	-		-
9	Recoverable Environmental		25,185	-	25,185	(25,185)	-	-	-	-	-		-
10	Other Operation & Maintenance		269,243	-	269,243	(814)	268,429	-	268,429	(7,360)	261,069	0.9806803	256,025
11	Depreciation & Amortization		142,390	-	142,390	(38,607)	103,783	-	103,783	(7,633)	96,150	0.9819407	94,414
12	Amortization of Investment Credit		(1,352)	-	(1,352)	-	(1,352)	-	(1,352)	331	(1,021)	0.9821029	(1,003)
13	Taxes Other Than Income Taxes		97,313	-	97,313	(67,331)	29,982	-	29,982	(1,531)	28,451	0.9786299	27,843
14	Income Taxes												
15	Federal		(92,341)	-	(92,341)	(22,773)	(115,114)	-	(115,114)	15,884	(99,230)	0.9229757	(91,587)
16	State		(2,439)	-	(2,439)	(3,788)	(6,227)	-	(6,227)	445	(5,782)	0.9229757	(5,337)
17	Deferred Income Taxes - Net												
18	Federal		161,110	-	161,110	-	161,110	-	161,110	(27,713)	133,397	0.9229757	123,122
19	State		13,212	-	13,212	-	13,212	-	13,212	(2,412)	10,800	0.9229757	9,968
20	Total Operating Expenses		1,251,243	-	1,251,243	(797,420)	453,823	-	453,823	(29,989)	423,834	0.9754899	413,446
21	Net Operating Income		188,653	-	188,653	(61,808)	126,845	-	126,845	(29,256)	97,589	0.9439301	92,117

Supporting Schedules: C-2, C-3, C-4, C-5, C-20, C-22, F-8

Recap Schedules: A-1, C-21

Schedule C-2 | NET OPERATING INCOME ADJUSTMENTS | Page 1 of 3

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide a schedule of net operating income adjustments for the test year, the prior year and the most recent historical year. Provide the details of all adjustments on Schedule C-3.

Type of Data Shown:
_X_ Projected Test Year Ended 12/31/14
____ Prior Year Ended 12/31/13
____ Historical Year Ended 12/31/12
Witness: S. D. Ritenour

Adjustments for the Twelve Months Ended 12/31/2014
($000's)

(1) Line No.	(2) Description	(3) Fuel Related Revenues & Expenses	(4) Conservation Revenues & Expenses	(5) PPCC Revenues & Expenses	(6) ECRC Revenues & Expenses	(7) Miscellaneous Adjustments	(8) Total Adjustments
1	Operating Revenues:						
2	Sales of Electricity	(651,123)	(26,405)	(63,154)	(153,917)	(32,339)	(926,938)
3	Other Operating Revenues	-	-	-	-	(42,247)	(42,247)
4	Total Operating Revenues	(651,123)	(26,405)	(63,154)	(153,917)	(74,586)	(969,185)
5	Operating Expenses:						
6	Recoverable Fuel	(650,274)	-	-	-	-	(650,274)
7	Recoverable Capacity	-	-	(65,247)	-	-	(65,247)
8	Recoverable Conservation	-	(23,520)	-	-	-	(23,520)
9	Recoverable Environmental	-	-	-	(29,077)	-	(29,077)
10	Other Operation & Maintenance	-	-	-	-	3,146	3,146
11	Depreciation & Amortization	-	(411)	-	(40,922)	(618)	(41,951)
12	Amortization of Investment Credit	-	-	-	-	-	-
13	Taxes Other Than Income Taxes	(379)	(710)	(43)	(2,261)	(74,639)	(78,032)
14	Income Taxes						
15	Federal	(155)	(583)	706	(27,008)	5,119	(21,921)
16	State	(26)	(97)	117	(4,491)	851	(3,646)
17	Deferred Income Taxes - Net						
18	Federal	-	-	-	-	-	-
19	State	-	-	-	-	-	-
20	Investment Tax Credit	-	-	-	-	-	-
21	Total Operating Expenses	(650,834)	(25,321)	(64,467)	(103,759)	(66,141)	(910,522)
22	Net Operating Income	(289)	(1,084)	1,313	(50,158)	(8,445)	(58,663)

Supporting Schedules: C-3

Recap Schedule: C-1

Schedule C-2 | NET OPERATING INCOME ADJUSTMENTS | Page 2 of 3

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide a schedule of net operating income adjustments for the test year, the prior year and the most recent historical year. Provide the details of all adjustments on Schedule C-3.

Type of Data Shown:
____Projected Test Year Ended 12/31/14
_X_Prior Year Ended 12/31/13
____Historical Year Ended 12/31/12
Witness: S. D. Ritenour

Adjustments for the Twelve Months Ended 12/31/2013
($000's)

(1) Line No.	(2) Description	(3) Fuel Related Revenues & Expenses	(4) Conservation Revenues & Expenses	(5) PPCC Revenues & Expenses	(6) ECRC Revenues & Expenses	(7) Miscellaneous Adjustments	(8) Total Adjustments
1	Operating Revenues:						
2	Sales of Electricity	(592,869)	(25,891)	(46,807)	(147,830)	(30,219)	(843,616)
3	Other Operating Revenues	(27,043)	-	-	-	(39,349)	(66,392)
4	Total Operating Revenues	(619,912)	(25,891)	(46,807)	(147,830)	(69,568)	(910,008)
5	Operating Expenses:						
6	Recoverable Fuel	(619,107)	-	-	-	-	(619,107)
7	Recoverable Capacity	-	-	(48,423)	-	-	(48,423)
8	Recoverable Conservation	-	(23,262)	-	-	-	(23,262)
9	Recoverable Environmental	-	-	-	(24,999)	-	(24,999)
10	Other Operation & Maintenance	-	-	-	-	(832)	(832)
11	Depreciation & Amortization	-	(336)	-	(40,764)	-	(41,100)
12	Amortization of Investment Credit	-	-	-	-	-	-
13	Taxes Other Than Income Taxes	(337)	(668)	(33)	(1,137)	(69,566)	(71,741)
14	Income Taxes						
15	Federal	(155)	(537)	545	(26,768)	5,932	(20,983)
16	State	(26)	(89)	91	(4,451)	986	(3,489)
17	Deferred Income Taxes - Net						
18	Federal	-	-	-	-	-	-
19	State	-	-	-	-	-	-
20	Investment Tax Credit	-	-	-	-	-	-
21	Total Operating Expenses	(619,625)	(24,892)	(47,820)	(98,119)	(63,480)	(853,936)
22	Net Operating Income	(287)	(999)	1,013	(49,711)	(6,088)	(56,072)

Supporting Schedules: C-3

Recap Schedule: C-1

Schedule C-2 | NET OPERATING INCOME ADJUSTMENTS | Page 3 of 3

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide a schedule of net operating income adjustments for the test year, the prior year and the most recent historical year. Provide the details of all adjustments on Schedule C-3.

Type of Data Shown:
____Projected Test Year Ended 12/31/14
____Prior Year Ended 12/31/13
_X_Historical Year Ended 12/31/12
Witness: S. D. Ritenour

Adjustments for the Twelve Months Ended 12/31/2012
($000's)

(1) Line No.	(2) Description	(3) Fuel Related Revenues & Expenses	(4) Conservation Revenues & Expenses	(5) PPCC Revenues & Expenses	(6) ECRC Revenues & Expenses	(7) Miscellaneous Adjustments	(8) Total Adjustments
1	Operating Revenues:						
2	Sales of Electricity	(582,487)	(25,200)	(35,080)	(139,770)	(28,254)	(810,791)
3	Other Operating Revenues	8,022	2,325	(8,892)	(12,130)	(37,762)	(48,437)
4	Total Operating Revenues	(574,465)	(22,875)	(43,972)	(151,900)	(66,016)	(859,228)
5	Operating Expenses:						
6	Recoverable Fuel	(572,512)	-	-	-	-	(572,512)
7	Recoverable Capacity	-	-	(45,500)	-	-	(45,500)
8	Recoverable Conservation	-	(20,910)	-	-	-	(20,910)
9	Recoverable Environmental	-	-	-	(25,185)	-	(25,185)
10	Other Operation & Maintenance	-	-	-	-	(814)	(814)
11	Depreciation & Amortization	-	(294)	-	(38,313)	-	(38,607)
12	Amortization of Investment Credit	-	-	-	-	-	-
13	Taxes Other Than Income Taxes	(315)	(152)	(25)	(1,008)	(65,831)	(67,331)
14	Income Taxes						
15	Federal	(542)	(502)	514	(28,906)	6,663	(22,773)
16	State	(90)	(84)	85	(4,807)	1,108	(3,788)
17	Deferred Income Taxes - Net						
18	Federal	-	-	-	-	-	-
19	State	-	-	-	-	-	-
20	Investment Tax Credit	-	-	-	-	-	-
21	Total Operating Expenses	(573,459)	(21,942)	(44,926)	(98,219)	(58,874)	(797,420)
22	Net Operating Income	(1,006)	(933)	954	(53,681)	(7,142)	(61,808)

Supporting Schedules: C-3

Recap Schedule: C-1

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: List and explain all proposed adjustments to net operating income for the test year, the prior year and the most recent historical year.

($000's)

Type of Data Shown:
__X__Projected Test Year Ended 12/31/14
____Prior Year Ended 12/31/13
____Historical Year Ended 12/31/12
Witness: S. D. Ritenour

(1) Line No.	(2) Adj No.	(3) Adjustment	(4) Reason for Adjustment or Omission (Provide Supporting Schedules)	(5) Total Adjustment	(6) Jurisdictional Factor	(7) Jurisdictional Adjustment
1		Commission Adjustments:				
2	(1)	Fuel Revenues	To remove all fuel-related revenues and expenses from NOI (net operating income) for ratemaking purposes.	(651,123)	Direct	(597,603)
4	(2)	Fuel Expense	To remove all fuel-related revenues and expenses from NOI for ratemaking purposes.	613,779	0.9206164	565,055
6	(3)	Fuel Expense - Interchange Energy	To remove all fuel-related revenues and expenses from NOI for ratemaking purposes.	35,992	0.8805846	31,694
8	(4)	Purchased Transmission	To remove expenses associated with transmission that are recoverable through the fuel clause.	403	0.9702233	391
10	(5)	Peabody Litigation Fees	To remove the Peabody litigation fees that are recoverable through the fuel clause.	100	0.9700000	97
12	(6)	ECCR Revenues	To remove all ECCR revenues and expenses from NOI for ratemaking purposes.	(26,405)	Direct	(26,405)
14	(7)	ECCR Expenses in O&M Expense	To remove all ECCR revenues and expenses from NOI for ratemaking purposes.	23,520	1.0000000	23,520

16 Legend:
17 ECCR Energy Conservation Cost Recovery Clause
18 PPCC Purchased Power Capacity Cost Recovery Clause
19 ECRC Environmental Cost Recovery Clause

Supporting Schedules: Recap Schedules: C-1, C-2

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: List and explain all proposed adjustments to net operating income for the test year, the prior year and the most recent historical year.

($000's)

Type of Data Shown:
_X_ Projected Test Year Ended 12/31/14
____ Prior Year Ended 12/31/13
____ Historical Year Ended 12/31/12
Witness: S. D. Ritenour

(1) Line No.	(2) Adj No.	(3) Adjustment	(4) Reason for Adjustment or Omission (Provide Supporting Schedules)	(5) Total Adjustment	(6) Jurisdictional Factor	(7) Jurisdictional Adjustment
1		Commission Adjustments (Continued):				
2	(8)	ECCR Depreciation	To remove all ECCR revenues and expenses	411	1.0000000	411
3			from NOI for ratemaking purposes.			
4	(9)	PPCC Revenues	To remove all PPCC revenues and expenses	(63,154)	Direct	(63,054)
5			from NOI for ratemaking purposes.			
6	(10)	PPCC Expenses	To remove all PPCC revenues and expenses	52,026	0.9657346	50,243
7			from NOI for ratemaking purposes.			
8	(11)	Purchased Transmission	To remove transmission expenses that are	13,221	0.9657346	12,768
9			recoverable through the capacity clause.			
10	(12)	ECRC Revenues	To remove all ECRC revenues and expenses	(153,917)	Direct	(149,312)
11			from NOI for ratemaking purposes.			
12	(13)	ECRC Expenses in O&M	To remove all ECRC revenues and expenses	29,077	0.9698043	28,199
13			from NOI for ratemaking purposes.			
14	(14)	ECRC in Depreciation Expense	To remove all ECRC revenues and expenses	40,922	0.9705293	39,716
15			from NOI for ratemaking purposes.			

16 Legend:
17 ECCR Energy Conservation Cost Recovery Clause
18 PPCC Purchased Power Capacity Cost Recovery Clause
19 ECRC Environmental Cost Recovery Clause

Supporting Schedules: Recap Schedules: C-1, C-2

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: List and explain all proposed adjustments to net operating income for the test year, the prior year and the most recent historical year.

($000's)

Type of Data Shown:
__X__Projected Test Year Ended 12/31/14
____Prior Year Ended 12/31/13
____Historical Year Ended 12/31/12
Witness: S. D. Ritenour

(1) Line No.	(2) Adj No.	(3) Adjustment	(4) Reason for Adjustment or Omission (Provide Supporting Schedules)	(5) Total Adjustment	(6) Jurisdictional Factor	(7) Jurisdictional Adjustment
1		Commission Adjustments (Continued):				
2	(15)	Gross Receipts & Franchise Fee Revenues	To remove gross receipts & franchise revenues from NOI for ratemaking purposes.	(74,586)	1.0000000	(74,586)
3						
4	(16)	Gross Receipts & Franchise Fee Expenses	To remove gross receipts & franchise expenses from NOI for ratemaking purposes.	74,531	1.0000000	74,531
5						
6	(17)	FPSC Assessment Fee on Franchise	To remove the FPSC assessment on Franchise	30	1.0000000	30
7		Fee Revenue	Fee revenues.			
8	(18)	Payroll Taxes-Liaison Office Salaries	To remove expenses associated with Gulf's liaison office	20	0.9830180	20
9			located in Tallahassee.			
10	(19)	ECRC Expenses in Other Tax Expense	To remove the ECRC payroll tax and ECRC property tax.	2,153	0.9702740	2,089
11	(20)	FPSC Assessment Fee on ECRC	To remove the FPSC assessment on ECRC revenues.	108	1.0000000	108
12		Revenues				
13	(21)	ECCR Expenses in Other Tax Expense	To remove the ECCR payroll tax & ECCR property tax.	691	1.0000000	691
14	(22)	FPSC Assessment Fee on ECCR	To remove the FPSC assessment on ECCR revenues.	19	1.0000000	19
15		Revenues				

16 Legend:
17 ECCR Energy Conservation Cost Recovery Clause
18 PPCC Purchased Power Capacity Cost Recovery Clause
19 ECRC Environmental Cost Recovery Clause

Supporting Schedules: Recap Schedules: C-1, C-2

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: List and explain all proposed adjustments to net operating income for the test year, the prior year and the most recent historical year.

($000's)

Type of Data Shown:
__X__Projected Test Year Ended 12/31/14
_____Prior Year Ended 12/31/13
_____Historical Year Ended 12/31/12
Witness: S. D. Ritenour

(1) Line No.	(2) Adj No.	(3) Adjustment	(4) Reason for Adjustment or Omission (Provide Supporting Schedules)	(5) Total Adjustment	(6) Jurisdictional Factor	(7) Jurisdictional Adjustment
1		Commission Adjustments (Continued):				
2	(23)	FPSC Assessment Fee on Fuel Revenues	To remove the FPSC Assessment fee on fuel revenues.	379	1.0000000	379
3	(24)	FPSC Assessment Fee on PPCC Revenues	To remove the FPSC Assessment fee on capacity revenues.	43	1.0000000	43
5	(25)	Institutional Advertising	To remove expenses related to institutional advertising.	30	0.9835526	30
7	(26)	Economic Development Expenses	To remove 5% of expenses related to economic development.	63	0.9997389	63
9	(27)	Tallahassee Liaison Expenses O&M	To remove expenses related to Gulf's liaison office located in Tallahassee.	306	0.9835526	301
11	(28)	Management Financial Planning Services	To remove the management financial planning services from net operating income.	41	0.9835526	40
13	(29)	Marketing Support Activities	To remove expenses that are promotional in nature.	156	1.0000000	156
15	(30)	Wholesale Sales Expense	To remove expense associated with wholesale activities.	255	1.0000000	255

Legend:

ECCR	Energy Conservation Cost Recovery Clause
PPCC	Purchased Power Capacity Cost Recovery Clause
ECRC	Environmental Cost Recovery Clause

Supporting Schedules:

Recap Schedules: C-1, C-2

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: List and explain all proposed adjustments to net operating income for the test year, the prior year and the most recent historical year.

($000's)

Type of Data Shown:
__X__Projected Test Year Ended 12/31/14
____Prior Year Ended 12/31/13
____Historical Year Ended 12/31/12
Witness: S. D. Ritenour

(1) Line No.	(2) Adj No.	(3) Adjustment	(4) Reason for Adjustment or Omission (Provide Supporting Schedules)	(5) Total Adjustment	(6) Jurisdictional Factor	(7) Jurisdictional Adjustment
1		Commission Adjustments (Continued):				
2	(31)	Income Taxes - Adjustments	To reflect the tax effect of all Commission	31,211		30,903
3			adjustments.			
4	(32)	Income Taxes - Interest Synchronization	To reflect the tax effect of interest	(6,925)		(6,816)
5			synchronization.			
6		Total Commission Adjustments		(56,623)		(56,024)
7		Company Adjustments:				
8	(33)	Increase in Property Insurance Reserve	To increase the property insurance	(5,500)	0.9845096	(5,415)
9			reserve annual accrual to $9 million.			
10	(34)	Amortization of Rate Case Expenses	To reflect the amortization of rate case	(930)	1.0000000	(930)
11			expenses.			
12	(35)	Distribution New Business Depreciation	To decrease depreciation related to new business	67	0.9999468	67
13			capital expenditures adjustment.			

14 Legend:
15 ECCR Energy Conservation Cost Recovery Clause
16 PPCC Purchased Power Capacity Cost Recovery Clause
17 ECRC Environmental Cost Recovery Clause

Supporting Schedules:

Recap Schedules: C-1, C-2

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: List and explain all proposed adjustments to net operating income for the test year, the prior year and the most recent historical year.

($000's)

Type of Data Shown:
_X_ Projected Test Year Ended 12/31/14
____ Prior Year Ended 12/31/13
____ Historical Year Ended 12/31/12
Witness: S. D. Ritenour

(1) Line No.	(2) Adj No.	(3) Adjustment	(4) Reason for Adjustment or Omission (Provide Supporting Schedules)	(5) Total Adjustment	(6) Jurisdictional Factor	(7) Jurisdictional Adjustment
1		Company Adjustments (Continued):				
2	(36)	Depreciation & Dismantlement Adj:	To adjust depreciation & dismantlement based on the	297	various	332
3		2013 Depreciation Study	2013 depreciation study.			
4	(37)	Hiring Lag Adjustment to O&M	To reflect the decrease in Operations & Maintenance	558	0.9836779	549
5			due to a hiring lag adjustment.			
6	(38)	Perdido Unit 3 Adjustment - Prop. Tax	To remove property tax expense associated with	58	0.9701749	56
7			Perdido Unit 3 .			
8	(39)	Perdido Unit 3 Adjustment - Prod. O&M	To remove production O&M associated with	400	0.9705189	388
9			Perdido Unit 3 .			
10	(40)	Perdido Unit 3 Adjustment - Depreciation	To remove depreciation expense associated with	254	0.9701809	246
11			Perdido Unit 3 .			
12	(41)	Scholz O&M - O&M	To reduce O&M expense associated with	1,475	0.9705159	1,432
13			Plant Scholz.			
14	(42)	Income Taxes - Adjustments	To reflect the tax effect of all Company adjustments.	1,281		1,263
15		Total Company Adjustments		(2,040)		(2,012)

16 Legend:
17 ECCR Energy Conservation Cost Recovery Clause
18 PPCC Purchased Power Capacity Cost Recovery Clause
19 ECRC Environmental Cost Recovery Clause

Supporting Schedules:

Recap Schedules: C-1, C-2

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

E PLANATION: List and explain all proposed adjustments to net operating income for the test year, the prior year and the most recent historical year.

($000's)

Type of Data Shown:
____Projected Test Year Ended 12/31/14
_X_Prior Year Ended 12/31/13
____Historical Year Ended 12/31/12
Witness: S. D. Ritenour

(1) Line No.	(2) Adj No.	(3) Adjustment	(4) Reason for Adjustment or Omission (Provide Supporting Schedules)	(5) Total Adjustment	(6) Jurisdictional Factor	(7) Jurisdictional Adjustment
1		Commission Adjustments:				
2	(1)	Fuel Revenues	To remove all fuel-related revenues and expenses from NOI (net operating income) for ratemaking purposes.	(619,912)	Direct	(568,509)
4	(2)	Fuel Expense	To remove all fuel-related revenues and expenses from NOI for ratemaking purposes.	584,163	0.9204554	537,696
6	(3)	Fuel Expense - Interchange Energy	To remove all fuel-related revenues and expenses from NOI for ratemaking purposes.	34,441	0.8705032	29,981
8	(4)	Purchased Transmission	To remove expenses associated with transmission that are recoverable through the fuel clause.	403	0.9727047	392
10	(5)	Peabody Litigation Fees	To remove the Peabody litigation fees that are recoverable through the fuel clause.	100	0.9700000	97
12	(6)	ECCR Revenues	To remove all ECCR revenues and expenses from NOI for ratemaking purposes.	(25,891)	Direct	(25,891)
14	(7)	ECCR Expenses in O&M Expense	To remove all ECCR revenues and expenses from NOI for ratemaking purposes.	23,262	1.0000000	23,262

16 Legend:
17 ECCR Energy Conservation Cost Recovery Clause
18 PPCC Purchased Power Capacity Cost Recovery Clause
19 ECRC Environmental Cost Recovery Clause

Supporting Schedules: Recap Schedules: C-1, C-2

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: List and explain all proposed adjustments to net operating income for the test year, the prior year and the most recent historical year.

($000's)

Type of Data Shown:
____Projected Test Year Ended 12/31/14
_X_Prior Year Ended 12/31/13
____Historical Year Ended 12/31/12
Witness: S. D. Ritenour

(1) Line No.	(2) Adj No.	(3) Adjustment	(4) Reason for Adjustment or Omission (Provide Supporting Schedules)	(5) Total Adjustment	(6) Jurisdictional Factor	(7) Jurisdictional Adjustment
1		Commission Adjustments (Continued):				
2	(8)	ECCR Depreciation	To remove all ECCR revenues and expenses	336	1.0000000	336
3			from NOI for ratemaking purposes.			
4	(9)	PPCC Revenues	To remove all PPCC revenues and expenses	(46,807)	Direct	(46,797)
5			from NOI for ratemaking purposes.			
6	(10)	PPCC Expenses	To remove all PPCC revenues and expenses	38,775	0.9657346	37,446
7			from NOI for ratemaking purposes.			
8	(11)	Purchased Transmission	To remove transmission expenses that are	9,648	0.9657346	9,317
9			recoverable through the capacity clause.			
10	(12)	ECRC Revenues	To remove all ECRC revenues and expenses	(147,830)	Direct	(143,501)
11			from NOI for ratemaking purposes.			
12	(13)	ECRC Expenses in O&M	To remove all ECRC revenues and expenses	24,999	0.9698043	24,244
13			from NOI for ratemaking purposes.			
14	(14)	ECRC in Depreciation Expense	To remove all ECRC revenues and expenses	40,764	0.9705293	39,563
15			from NOI for ratemaking purposes.			

16 Legend:
17 ECCR Energy Conservation Cost Recovery Clause
18 PPCC Purchased Power Capacity Cost Recovery Clause
19 ECRC Environmental Cost Recovery Clause

Supporting Schedules: Recap Schedules: C-1, C-2

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: List and explain all proposed adjustments to net operating income for the test year, the prior year and the most recent historical year.

($000's)

Type of Data Shown:
____Projected Test Year Ended 12/31/14
__X__Prior Year Ended 12/31/13
____Historical Year Ended 12/31/12
Witness: S. D. Ritenour

(1) Line No.	(2) Adj No.	(3) Adjustment	(4) Reason for Adjustment or Omission (Provide Supporting Schedules)	(5) Total Adjustment	(6) Jurisdictional Factor	(7) Jurisdictional Adjustment
1		Commission Adjustments (Continued):				
2	(15)	Gross Receipts & Franchise Fee Revenues	To remove gross receipts & franchise revenues	(69,568)	1.0000000	(69,568)
3			from NOI for ratemaking purposes.			
4	(16)	Gross Receipts & Franchise Fee Expenses	To remove gross receipts & franchise expenses	69,518	1.0000000	69,518
5			from NOI for ratemaking purposes.			
6	(17)	FPSC Assessment Fee on Franchise	To remove the FPSC assessment on Franchise	28	1.0000000	28
7		Fee Revenue	Fee revenues.			
8	(18)	Payroll Taxes-Liaison Office Salaries	To remove expenses associated with Gulf's liaison office	20	0.9830180	20
9			located in Tallahassee.			
10	(19)	ECRC Expenses in Other Tax Expense	To remove the ECRC payroll tax and ECRC property tax.	1,034	0.9702740	1,003
11	(20)	FPSC Assessment Fee on ECRC	To remove the FPSC assessment on ECRC revenues.	103	1.0000000	103
12		Revenues				
13	(21)	ECCR Expenses in Other Tax Expense	To remove the ECCR payroll tax & ECCR property tax.	649	1.0000000	649
14	(22)	FPSC Assessment Fee on ECCR	To remove the FPSC assessment on ECCR revenues.	19	1.0000000	19
15		Revenues				

16 Legend:
17 ECCR Energy Conservation Cost Recovery Clause
18 PPCC Purchased Power Capacity Cost Recovery Clause
19 ECRC Environmental Cost Recovery Clause

Supporting Schedules:

Recap Schedules: C-1, C-2

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: List and explain all proposed adjustments to net operating income for the test year, the prior year and the most recent historical year.

($000's)

Type of Data Shown:
____Projected Test Year Ended 12/31/14
__X__Prior Year Ended 12/31/13
____Historical Year Ended 12/31/12
Witness: S. D. Ritenour

(1) Line No.	(2) Adj No.	(3) Adjustment	(4) Reason for Adjustment or Omission (Provide Supporting Schedules)	(5) Total Adjustment	(6) Jurisdictional Factor	(7) Jurisdictional Adjustment
1		Commission Adjustments (Continued):				
2	(23)	FPSC Assessment Fee on Fuel Revenues	To remove the FPSC Assessment fee on fuel revenues.	337	1.0000000	337
3	(24)	FPSC Assessment Fee on PPCC Revenues	To remove the FPSC Assessment fee on capacity revenues.	33	1.0000000	33
5	(25)	Institutional Advertising	To remove expenses related to institutional advertising.	30	0.9835526	30
7	(26)	Economic Development Expenses	To remove 5% of expenses related to economic development.	62	0.9997389	62
9	(27)	Tallahassee Liaison Expenses O&M	To remove expenses related to Gulf's liaison office located in Tallahassee.	299	0.9835526	294
11	(28)	Management Financial Planning Services	To remove the management financial planning services from net operating income.	41	0.9835526	40
13	(29)	Marketing Support Activities	To remove expenses that are promotional in nature.	156	1.0000000	156
15	(30)	Wholesale Sales Expense	To remove expense associated with wholesale activities.	244	1.0000000	244

Legend:

ECCR	Energy Conservation Cost Recovery Clause
PPCC	Purchased Power Capacity Cost Recovery Clause
ECRC	Environmental Cost Recovery Clause

Supporting Schedules: Recap Schedules: C-1, C-2

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

E PLANATION: List and explain all proposed adjustments to net operating income for the test year, the prior year and the most recent historical year.

($000's)

Type of Data Shown:
____Projected Test Year Ended 12/31/14
__X__Prior Year Ended 12/31/13
____Historical Year Ended 12/31/12
Witness: S. D. Ritenour

(1) Line No.	(2) Adj No.	(3) Adjustment	(4) Reason for Adjustment or Omission (Provide Supporting Schedules)	(5) Total Adjustment	(6) Jurisdictional Factor	(7) Jurisdictional Adjustment
1		Commission Adjustments (Continued):				
2	(31)	Income Taxes - Adjustments	To reflect the tax effect of all Commission	31,070		30,627
3			adjustments.			
4	(32)	Income Taxes - Interest Synchronization	To reflect the tax effect of interest	(6,598)		(6,468)
5			synchronization.			
6		Total Commission Adjustments		(56,072)		(55,237)
7		Company Adjustments:				
8		There are no Company adjustments for the prior year.		-		-

9	Legend:	
10	ECCR	Energy Conservation Cost Recovery Clause
11	PPCC	Purchased Power Capacity Cost Recovery Clause
12	ECRC	Environmental Cost Recovery Clause

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: List and explain all proposed adjustments to net operating income for the test year, the prior year and the most recent historical year.

($000's)

Type of Data Shown:
____Projected Test Year Ended 12/31/14
____Prior Year Ended 12/31/13
__X__Historical Year Ended 12/31/12
Witness: S. D. Ritenour

(1) Line No.	(2) Adj No.	(3) Adjustment	(4) Reason for Adjustment or Omission (Provide Supporting Schedules)	(5) Total Adjustment	(6) Jurisdictional Factor	(7) Jurisdictional Adjustment
1		Commission Adjustments:				
2	(1)	Fuel Revenues	To remove all fuel-related revenues and expenses from NOI (net operating income) for ratemaking purposes.	(574,465)	Direct	(544,016)
4	(2)	Fuel Expense	To remove all fuel-related revenues and expenses from NOI for ratemaking purposes.	537,949	0.9488576	510,437
6	(3)	Fuel Expense - Interchange Energy	To remove all fuel-related revenues and expenses from NOI for ratemaking purposes.	33,960	0.9600412	32,603
8	(4)	Purchased Transmission	To remove expenses associated with transmission that are recoverable through the fuel clause.	464	0.9719828	451
10	(5)	Peabody Litigation Fees	To remove the Peabody litigation fees that are recoverable through the fuel clause.	139	0.9712230	135
12	(6)	ECCR Revenues	To remove all ECCR revenues and expenses from NOI for ratemaking purposes.	(22,875)	Direct	(22,875)
14	(7)	ECCR Expenses in O&M Expense	To remove all ECCR revenues and expenses from NOI for ratemaking purposes.	20,910	1.0000000	20,910
16	(8)	ECCR Depreciation	To remove all ECCR revenues and expenses from NOI for ratemaking purposes.	294	1.0000000	294

Legend:

ECCR	Energy Conservation Cost Recovery Clause
PPCC	Purchased Power Capacity Cost Recovery Clause
ECRC	Environmental Cost Recovery Clause

Supporting Schedules:

Recap Schedules: C-1, C-2

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: List and explain all proposed adjustments to net operating income for the test year, the prior year and the most recent historical year.

($000's)

Type of Data Shown:
____Projected Test Year Ended 12/31/14
____Prior Year Ended 12/31/13
_X_Historical Year Ended 12/31/12
Witness: S. D. Ritenour

(1) Line No.	(2) Adj No.	(3) Adjustment	(4) Reason for Adjustment or Omission (Provide Supporting Schedules)	(5) Total Adjustment	(6) Jurisdictional Factor	(7) Jurisdictional Adjustment
1		Commission Adjustments (Continued):				
2	(9)	PPCC Revenues	To remove all PPCC revenues and expenses	(43,972)	Direct	(43,959)
3			from NOI for ratemaking purposes.			
4	(10)	PPCC Expenses	To remove all PPCC revenues and expenses	40,126	0.9657346	38,751
5			from NOI for ratemaking purposes.			
6	(11)	Purchased Transmission	To remove transmission expenses that are	5,374	0.9657346	5,190
7			recoverable through the capacity clause.			
8	(12)	ECRC Revenues	To remove all ECRC revenues and expenses	(151,900)	Direct	(147,768)
9			from NOI for ratemaking purposes.			
10	(13)	ECRC Expenses in O&M	To remove all ECRC revenues and expenses	25,185	0.9698043	24,425
11			from NOI for ratemaking purposes.			
12	(14)	ECRC in Depreciation Expense	To remove all ECRC revenues and expenses	38,313	0.9705293	37,184
13			from NOI for ratemaking purposes.			
14	(15)	Gross Receipts & Franchise Fee Revenues	To remove gross receipts & franchise revenues	(66,016)	1.0000000	(66,016)
15			from NOI for ratemaking purposes.			
16	(16)	Gross Receipts & Franchise Fee Expenses	To remove gross receipts & franchise expenses	65,783	1.0000000	65,783
17			from NOI for ratemaking purposes.			

18 Legend:
19 ECCR Energy Conservation Cost Recovery Clause
20 PPCC Purchased Power Capacity Cost Recovery Clause
21 ECRC Environmental Cost Recovery Clause

Supporting Schedules:

Recap Schedules: C-1, C-2

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

E PLANATION: List and explain all proposed adjustments to net operating income for the test year, the prior year and the most recent historical year.

($000's)

Type of Data Shown:
____Projected Test Year Ended 12/31/14
____Prior Year Ended 12/31/13
_X_Historical Year Ended 12/31/12
Witness: S. D. Ritenour

(1) Line No.	(2) Adj No.	(3) Adjustment	(4) Reason for Adjustment or Omission (Provide Supporting Schedules)	(5) Total Adjustment	(6) Jurisdictional Factor	(7) Jurisdictional Adjustment
1		Commission Adjustments (Continued):				
2 3	(17)	FPSC Assessment Fee on Franchise Fee Revenue	To remove the FPSC assessment on Franchise Fee revenues.	27	1.0000000	27
4 5	(18)	Payroll Taxes-Liaison Office Salaries	To remove expenses associated with Gulf's liaison office located in Tallahassee.	21	0.9830180	21
6	(19)	ECRC Expenses in Other Tax Expense	To remove the ECRC payroll tax and ECRC property tax.	902	0.9702740	875
7 8	(20)	FPSC Assessment Fee on ECRC Revenues	To remove the FPSC assessment on ECRC revenues.	106	1.0000000	106
9	(21)	ECCR Expenses in Other Tax Expense	To remove the ECCR payroll tax & ECCR property tax.	136	1.0000000	136
10 11	(22)	FPSC Assessment Fee on ECCR Revenues	To remove the FPSC assessment on ECCR revenues.	16	1.0000000	16
12	(23)	FPSC Assessment Fee on Fuel Revenues	To remove the FPSC Assessment fee on fuel revenues.	315	1.0000000	315
13 14	(24)	FPSC Assessment Fee on PPCC Revenues	To remove the FPSC Assessment fee on capacity revenues.	25	1.0000000	25

15 Legend:
16 ECCR Energy Conservation Cost Recovery Clause
17 PPCC Purchased Power Capacity Cost Recovery Clause
18 ECRC Environmental Cost Recovery Clause

Supporting Schedules:

Recap Schedules: C-1, C-2

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

E PLANATION: List and explain all proposed adjustments to net operating income for the test year, the prior year and the most recent historical year.

($000's)

Type of Data Shown:
____Projected Test Year Ended 12/31/14
____Prior Year Ended 12/31/13
__X__Historical Year Ended 12/31/12
Witness: S. D. Ritenour

(1) Line No.	(2) Adj No.	(3) Adjustment	(4) Reason for Adjustment or Omission (Provide Supporting Schedules)	(5) Total Adjustment	(6) Jurisdictional Factor	(7) Jurisdictional Adjustment
1		Commission Adjustments (Continued):				
2	(25)	Institutional Advertising	To remove expenses related to institutional advertising.	5	0.9835526	5
3						
4	(26)	Economic Development Expenses	To remove 5% of expenses related to economic development.	41	0.9997389	41
5						
6	(27)	Tallahassee Liaison Expenses O&M	To remove expenses related to Gulf's liaison office located in Tallahassee.	426	0.9835526	419
7						
8	(28)	Management Financial Planning Services	To remove the management financial planning services from net operating income.	37	0.9835526	36
9						
10	(29)	Marketing Support Activities	To remove expenses that are promotional in nature.	168	1.0000000	168
11						
12	(30)	Wholesale Sales Expense	To remove expense associated with wholesale activities.	137	1.0000000	137
13						

14	Legend:	
15	ECCR	Energy Conservation Cost Recovery Clause
16	PPCC	Purchased Power Capacity Cost Recovery Clause
17	ECRC	Environmental Cost Recovery Clause

Supporting Schedules:

Recap Schedules: C-1, C-2

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: List and explain all proposed adjustments to net operating income for the test year, the prior year and the most recent historical year.

($000's)

Type of Data Shown:
____Projected Test Year Ended 12/31/14
____Prior Year Ended 12/31/13
__X__Historical Year Ended 12/31/12
Witness: S. D. Ritenour

(1) Line No.	(2) Adj No.	(3) Adjustment	(4) Reason for Adjustment or Omission (Provide Supporting Schedules)	(5) Total Adjustment	(6) Jurisdictional Factor	(7) Jurisdictional Adjustment
1		Commission Adjustments (Continued):				
2	(31)	Income Taxes - Adjustments	To reflect the tax effect of all Commission adjustments.	34,089		33,230
3						
4	(32)	Income Taxes - Interest Synchronization	To reflect the tax effect of interest synchronization.	(7,528)		(7,388)
5						
6		Total Commission Adjustments		(61,808)		(60,302)
7		Company Adjustments:				
8		There are no Company adjustments for the prior year.		-		-

9	Legend:	
10	ECCR	Energy Conservation Cost Recovery Clause
11	PPCC	Purchased Power Capacity Cost Recovery Clause
12	ECRC	Environmental Cost Recovery Clause

Supporting Schedules:

Recap Schedules: C-1, C-2

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide jurisdictional factors for net operating income for the test year, and the prior year if the test year is projected.

Type of Data Shown:
X Projected Test Year Ended 12/31/14
__ Prior Year Ended 12/31/13
__ Historical Year Ended 12/31/12
Witness: M. T. O'Sheasy

($000's)

(1) Line No.	(2) Account Number	(3) Description	(4) Total Adjusted Utility	(5) Unit Power Sales	(6) Total Adjusted Utility Net of UPS	(7) Jurisdictional Amount	(8) Jurisdictional Separation Factor
1		OPERATING REVENUES					
2	440-447	REVENUES FROM SALES	510,734	0	510,734	498,493	0.9760325
3		OTHER OPERATING REVENUES:					
4	451	Misc. Service Revenues	4,789	0	4,789	4,789	1.0000000
5	454	Rent from Electric Property	6,335	0	6,335	6,314	0.9966851
6	455	Interdepartmental Rental	0	0	0	0	0.0000000
7	456	Other Electric Revenues	15,800	0	15,800	11,928	0.7549367
8		TOTAL OTHER OPERATING REVENUES	26,924	0	26,924	23,031	0.8554078
9	447	SALES TO NON-ASSOCIATED COMPANIES	65,602	58,261	7,341	7,127	0.9708487
10		TOTAL REVENUES	603,260	58,261	544,999	528,651	0.9700036
11		OPERATION AND MAINTENANCE EXPENSES					
12		STEAM POWER GENERATION					
13		OPERATION EXPENSE:					
14	500	Supervision & Engineering	11,719	282	11,437	11,096	0.9701845
15	501	Fuel (Net)	6,543	471	6,072	5,895	0.9708498
16	502	Steam	8,271	1,320	6,951	6,746	0.9705078
17	505	Electric	4,131	208	3,923	3,807	0.9704308
18	506	Miscellaneous Steam	15,224	823	14,401	13,972	0.9702104
19	507	Rents	0	0	0	0	0.0000000
20	509	Allowances	0	0	0	0	0.0000000
21		TOTAL OPERATION	45,888	3,104	42,784	41,516	0.9703628
22		MAINTENANCE EXPENSE:					
23	510	Supervision & Engineering	9,886	651	9,235	8,960	0.9702220
24	511	Structures	5,707	330	5,377	5,217	0.9702436
25	512	Boiler Plant	28,745	5,020	23,725	23,031	0.9707482
26	513	Electric Plant	8,437	708	7,729	7,503	0.9707595
27	514	Miscellaneous Steam	3,132	258	2,874	2,788	0.9700765
28		TOTAL MAINTENANCE	55,907	6,967	48,940	47,499	0.9705558
29		TOTAL STEAM POWER GENERATION	101,795	10,071	91,724	89,015	0.9704657

Supporting Schedules: Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide jurisdictional factors for net operating income for the test year, and the prior year if the test year is projected.

Type of Data Shown:
X Projected Test Year Ended 12/31/14
__ Prior Year Ended 12/31/13
__ Historical Year Ended 12/31/12
Witness: M. T. O'Sheasy

($000's)

(1) Line No.	(2) Account Number	(3) Description	(4) Total Adjusted Utility	(5) Unit Power Sales	(6) Total Adjusted Utility Net of UPS	(7) Jurisdictional Amount	(8) Jurisdictional Separation Factor
1		OTHER POWER GENERATION					
2		OPERATING EXPENSE:					
3	546	Supervision	1,701	0	1,701	1,650	0.9701833
4	547	Energy	580	0	580	563	0.9708345
5	547	Fuel (Net)	0	0	0	0	0.0000000
6	548	Generation	528	0	528	512	0.9701833
7	549	Miscellaneous	848	0	848	823	0.9701833
8		Total Operation	3,657	0	3,657	3,548	0.9701941
9		MAINTENANCE EXPENSE:					
10	551	Supervision & Engineering	296	0	296	287	0.9701833
11	552	Structures	0	0	0	0	0.9701833
12	553	Generating & Electric Equipment	6,665	0	6,665	6,466	0.9701425
13	554	Miscellaneous	524	0	524	508	0.9694656
14		Total Maintenance Expense	7,485	0	7,485	7,261	0.9700735
15		TOTAL OTHER POWER GENERATION	11,142	0	11,142	10,809	0.9701131
16	555	PURCHASED POWER	0	0	0	0	0.0000000
17	556	SYSTEM CONTROL & LOAD DISPATCH	1,817	0	1,817	1,763	0.9702807
18	557	OTHER EXPENSES	2,054	0	2,054	1,993	0.9701833
19		TOTAL PRODUCTION	116,808	10,071	106,737	103,580	0.9704226
20		TRANSMISSION EXPENSE					
21		OPERATIONS:					
22	560	Supervision & Engineering	1,609	1	1,608	1,560	0.9701493
23	561	Load Dispatching	3,526	2	3,524	3,419	0.9701833
24	562	Station Expenses	43	0	43	42	0.9767442
25	563	Overhead Lines	191	0	191	185	0.9685864
26	564	Underground Lines	0	0	0	0	0.0000000
27	565	Transmission of Elec.	(301)	0	(301)	(292)	0.0000000
28	566	Miscellaneous	1,038	1	1,037	1,006	0.9701061
29	567	Rents	165	0	165	160	0.9696970
30		Total Operation	6,271	4	6,267	6,080	0.9701612

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide jurisdictional factors for net operating income for the test year, and the prior year if the test year is projected.

Type of Data Shown:
X Projected Test Year Ended 12/31/14
__ Prior Year Ended 12/31/13
__ Historical Year Ended 12/31/12
Witness: M. T. O'Sheasy

($000's)

(1) Line No.	(2) Account Number	(3) Description	(4) Total Adjusted Utility	(5) Unit Power Sales	(6) Total Adjusted Utility Net of UPS	(7) Jurisdictional Amount	(8) Jurisdictional Separation Factor
1		MAINTENANCE:					
2	568	Supervision & Engineering	1,052	0	1,052	1,021	0.9705323
3	569	Structures	1,003	0	1,003	973	0.9700897
4	570	Station Equipment	830	0	830	811	0.9771084
5	571	Overhead Lines	4,479	0	4,479	4,345	0.9700826
6	573	Miscellaneous	102	0	102	99	0.9705882
7		Total Maintenance Expense	7,466	0	7,466	7,249	0.9709349
8		TOTAL TRANSMISSION	13,737	4	13,733	13,329	0.9705818
9		DISTRIBUTION EXPENSE					
10		OPERATION:					
11	580	Supervision & Engineering	6,768	0	6,768	6,762	0.9991135
12	581	Load Dispatching	902	0	902	902	1.0000000
13	582	Station Expenses	308	0	308	303	0.9837662
14	583	Overhead Lines	2,579	0	2,579	2,579	1.0000000
15	584	Underground Lines	739	0	739	739	1.0000000
16	585	Street Lighting	598	0	598	598	1.0000000
17	586	Meters	2,627	0	2,627	2,624	0.9988580
18	587	Customer Installations	1,331	0	1,331	1,331	1.0000000
19	588	Miscellaneous	4,363	0	4,363	4,360	0.9993124
20	589	Rents	0	0	0	0	0.0000000
21		Total Operation	20,215	0	20,215	20,198	0.9991590

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide jurisdictional factors for net operating income for the test year, and the prior year if the test year is projected.

Type of Data Shown:
X Projected Test Year Ended 12/31/14
__ Prior Year Ended 12/31/13
__ Historical Year Ended 12/31/12
Witness: M. T. O'Sheasy

($000's)

(1) Line No.	(2) Account Number	(3) Description	(4) Total Adjusted Utility	(5) Unit Power Sales	(6) Total Adjusted Utility Net of UPS	(7) Jurisdictional Amount	(8) Jurisdictional Separation Factor
1		MAINTENANCE:					
2	590	Supervision & Engineering	3,664	0	3,664	3,660	0.9989083
3	591	Structures	28	0	28	27	0.9642857
4	592	Station Equipment	962	0	962	946	0.9833680
5	593	Overhead Lines	13,075	0	13,075	13,075	1.0000000
6	594	Underground Lines	1,897	0	1,897	1,897	1.0000000
7	595	Line Transformers	1,001	0	1,001	1,001	1.0000000
8	596	Street Lighting	597	0	597	597	1.0000000
9	597	Meters	159	0	159	159	1.0000000
10	598	Miscellaneous	472	0	472	472	1.0000000
11		Total Maintenance Expense	21,855	0	21,855	21,834	0.9990391
12		TOTAL DISTRIBUTION	42,070	0	42,070	42,032	0.9990967
13	901-905	CUSTOMER ACCOUNTS EXPENSE	21,986	0	21,986	21,807	0.9918585
14	904	UNCOLLECTIBLE EXPENSE	3,809	0	3,809	3,809	1.0000000
15		TOTAL CUST ACCTS EXP & UNCOLL EXP	25,795	0	25,795	25,616	0.9930607
16		CUSTOMER ASSISTANCE EXPENSE					
17	907/911	Supervision	1,829	0	1,829	1,829	1.0000000
18	908/912	Customer Assistance	14,564	0	14,564	14,564	1.0000000
19	909/913	Informational & Instructional Advertising	1,232	0	1,232	1,232	1.0000000
20	910	Miscellaneous	190	0	190	190	1.0000000
21		Energy Conservation Costs	0	0	0	0	0.0000000
22		TOTAL CUSTOMER ASSISTANCE	17,815	0	17,815	17,815	1.0000000
23	920-932	ADMINISTRATIVE & GENERAL EXPENSE	96,192	2,617	93,575	91,636	0.9792787
24	904	LESS: UNCOLLECTIBLE EXPENSE	3,809	0	3,809	3,809	1.0000000
25		TOTAL A&G EXP LESS UNCOLL EXP	92,383	2,617	89,766	87,827	0.9783994
26		TOTAL OPERATION & MAINTENANCE EXP	308,608	12,692	295,916	290,199	0.9806803

Supporting Schedules: Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide jurisdictional factors for net operating income for the test year, and the prior year if the test year is projected.

Type of Data Shown:
X Projected Test Year Ended 12/31/14
__ Prior Year Ended 12/31/13
__ Historical Year Ended 12/31/12
Witness: M. T. O'Sheasy

($000's)

(1) Line No.	(2) Account Number	(3) Description	(4) Total Adjusted Utility	(5) Unit Power Sales	(6) Total Adjusted Utility Net of UPS	(7) Jurisdictional Amount	(8) Jurisdictional Separation Factor
1		DEPRECIATION EXPENSE					
2	300-346	PRODUCTION PLANT	52,105	7,771	44,334	43,012	0.9701809
3		TRANSMISSION PLANT					
4	350	Easements & Rights-of-Way	211	0	211	205	0.9715640
5	352	Structures & Improvements	197	0	197	192	0.9746193
6	353	Station Equipment	3,896	119	3,777	3,692	0.9774954
7	354	Towers and Fixtures	767	0	767	744	0.9701833
8	355	Poles and Fixtures	5,796	0	5,796	5,623	0.9701833
9	356	Overhead Conductors and Devices	2,138	0	2,138	2,074	0.9701833
10	358	Underground Conductors and Devices	254	0	254	246	0.9701833
11	359	Roads and Trails	5	0	5	5	0.9701833
12		TOTAL TRANSMISSION	13,264	119	13,145	12,781	0.9723089
13		DISTRIBUTION PLANT					
14	360	Easements & Rights-of-Way	13	0	13	13	1.0000000
15	361	Structures and Improvements	441	0	441	433	0.9818594
16	362	Station Equipment	5,191	0	5,191	5,107	0.9838181
17	364	Poles, Towers and Fixtures	6,281	0	6,281	6,281	1.0000000
18	365	Overhead Conductors and Devices	4,398	0	4,398	4,398	1.0000000
19	366	Underground Conduits	14	0	14	14	1.0000000
20	367	Underground Conductors and Devices	4,533	0	4,533	4,533	1.0000000
21	368	Line Transformers	9,621	0	9,621	9,621	1.0000000
22	369	Services	2,838	0	2,838	2,838	1.0000000
23	370	Meters	4,485	0	4,485	4,477	0.9982163
24	373	Street Lighting	2,871	0	2,871	2,871	1.0000000
25		TOTAL DISTRIBUTION	40,686	0	40,686	40,586	0.9975422
26	389-398	GENERAL PLANT	8,347	85	8,262	8,126	0.9835391
27		TOTAL DEPRECIATION	114,402	7,975	106,427	104,505	0.9819407

Supporting Schedules: Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide jurisdictional factors for net operating income for the test year, and the prior year if the test year is projected.

Type of Data Shown:
X Projected Test Year Ended 12/31/14
__ Prior Year Ended 12/31/13
__ Historical Year Ended 12/31/12
Witness: M. T. O'Sheasy

($000's)

(1) Line No.	(2) Account Number	(3) Description	(4) Total Adjusted Utility	(5) Unit Power Sales	(6) Total Adjusted Utility Net of UPS	(7) Jurisdictional Amount	(8) Jurisdictional Separation Factor
1	404	AMORT. OF INVESTMENT TAX CREDITS	(1,224)	(330)	(894)	(878)	0.9821029
2	407	OTHER AMORTIZATION	0	0	0	0	0.0000000
3		TAXES OTHER THAN INCOME TAXES					
4	408	Real and Personal Property Taxes	26,010	915	25,095	24,515	0.9768878
5	408	Payroll Taxes	6,917	204	6,713	6,599	0.9830180
6	408	Revenue Taxes	402	0	402	402	1.0000000
7	408	Other	412	0	412	401	0.9733010
8		TOTAL TAXES OTHER THAN INCOME	33,741	1,119	32,622	31,917	0.9783888
9		EXPENSES EXCLUDING INCOME TAXES	455,527	21,456	434,071	425,743	0.9808142
10		OPERATING INCOME BEFORE INC. TAXES	147,733	36,805	110,928	102,908	0.9277009
11	409	TOTAL INCOME TAXES	41,601	12,227	29,374	26,549	0.9038265
12		NET OPERATING INCOME	106,132	24,578	81,554	76,359	0.9362999

Schedule C-5 | OPERATING REVENUES DETAIL | Page 1 of 3

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

EXPLANATION: Provide a schedule of operating revenue by primary account for the test year. Provide the per books amounts and the adjustments required to adjust the per books amounts to reflect the requested test year operating revenues.

Type of Data Shown:
X Projected Test Year Ended 12/31/14
____ Prior Year Ended 12/31/13
____ Historical Year Ended 12/31/12
Witness: S. D. Ritenour

DOCKET NO.: 130140-EI

($000's)

(1) Line No.	(2) Acct No.	(3) Account Title	(4) Per Books	(5) Non-Utility	(6) Electric Utility (4)-(5)	Adjustments (7) Fuel	(8) PPCC	(9) ECCR	(10) ECRC	(11) Franchise Fees & GRT	(12) UPS	(13) Other	(14) Total (7) thru (13)	(15) Adjusted Total (6)-(14)
1		SALES OF ELECTRICITY												
2	440	Residential Sales	682,735	-	682,735	249,394	33,695	12,423	70,338	17,071	-	-	382,921	299,814
3	442	Commercial Sales	433,757	-	433,757	194,088	18,262	9,782	43,366	10,845	-	-	276,343	157,414
4	442	Industrial Sales	170,971	-	170,971	81,921	8,235	4,140	34,259	4,275	-	-	132,830	38,141
5	444	Public Street & Highway Lighting	5,939	-	5,939	1,213	48	60	1,349	148	-	-	2,818	3,121
6	445	Other Sales to Public Authorities	-	-	-	-	-	-	-	-	-	-	-	-
7	446	Sales to Railroads & Railways	-	-	-	-	-	-	-	-	-	-	-	-
8	448	Interdepartmental Sales	-	-	-	-	-	-	-	-	-	-	-	-
9		Total Sales to Ultimate Consumers	1,293,402	-	1,293,402	526,616	60,240	26,405	149,312	32,339	-	-	794,912	498,490
10	447	Sales for Resale	209,872	-	209,872	124,507	2,914		4,605		58,261		190,287	19,585
11		TOTAL SALES OF ELECTRICITY	1,503,274	-	1,503,274	651,123	63,154	26,405	153,917	32,339	58,261	-	985,199	518,075
12	449.1	(Less) Provision for Rate Refunds	-		-								-	-
13		TOTAL REVENUE NET OF REFUND PROVISION	1,503,274	-	1,503,274	651,123	63,154	26,405	153,917	32,339	58,261	-	985,199	518,075
14		OTHER OPERATING REVENUES												
15	450	Forfeited Discounts	-	-	-	-	-	-	-	-	-	-	-	-
16	451	Miscellaneous Service Revenues	47,036	-	47,036	-	-	-	-	42,247	-	-	42,247	4,789
17	453	Sales of Water and Water Power	-	-	-	-	-	-	-	-	-	-	-	-
18	454	Rent from Electric Property	6,331	-	6,331	-	-	-	-	-	-	-	-	6,331
19	455	Interdepartmental Rents	-	-	-	-	-	-	-	-	-	-	-	-
20	456	Deferred Fuel Revenue	-	-	-	-	-	-	-	-	-	-	-	-
21	456	Unbilled Revenue	-	-	-	-	-	-	-	-	-	-	-	-
22	456	Other Electric Revenues (In Detail)	15,804	-	15,804	-	-	-	-	-	-	-	-	15,804
23		TOTAL OTHER OPERATING REVENUES	69,171	-	69,171	-	-	-	-	42,247	-	-	42,247	26,924
24		TOTAL ELECTRIC OPERATING REVENUES	1,572,445	-	1,572,445	651,123	63,154	26,405	153,917	74,586	58,261	-	1,027,446	544,999

Supporting Schedules:

Recap Schedules: C-1, C-21

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide a schedule of operating revenue by primary account for the test year. Provide the per books amounts and the adjustments required to adjust the per books amounts to reflect the requested test year operating revenues.

Type of Data Shown:
____Projected Test Year Ended 12/31/14
__X__Prior Year Ended 12/31/13
____Historical Year Ended 12/31/12
Witness: S. D. Ritenour

($000's)

(1) Line No.	(2) Acct No.	(3) Account Title	(4) Per Books	(5) Non-Utility	(6) Electric Utility (4)-(5)	Adjustments (7) Fuel	(8) PPCC	(9) ECCR	(10) ECRC	(11) Franchise Fees & GRT	(12) UPS	(13) Other	(14) Total (7) thru (13)	(15) Adjusted Total (6)-(14)
1		SALES OF ELECTRICITY												
2	440	Residential Sales	629,409	-	629,409	209,077	26,013	12,259	67,451	15,738	-	-	330,538	298,871
3	442	Commercial Sales	410,486	-	410,486	180,178	14,098	9,489	41,710	10,263	-	-	255,738	154,748
4	442	Industrial Sales	162,907	-	162,907	77,290	6,358	4,083	33,032	4,073	-	-	124,836	38,071
5	444	Public Street & Highway Lighting	5,813	-	5,813	1,142	37	60	1,308	145	-	-	2,692	3,121
6	445	Other Sales to Public Authorities	-	-	-	-	-	-	-	-	-	-	-	-
7	446	Sales to Railroads & Railways	-	-	-	-	-	-	-	-	-	-	-	-
8	448	Interdepartmental Sales	-	-	-	-	-	-	-	-	-	-	-	-
9		Total Sales to Ultimate Consumers	1,208,615	-	1,208,615	467,687	46,506	25,891	143,501	30,219	-	-	713,804	494,811
10	447	Sales for Resale	206,423	-	206,423	125,182	301		4,329		58,195		188,007	18,416
11		TOTAL SALES OF ELECTRICITY	1,415,038	-	1,415,038	592,869	46,807	25,891	147,830	30,219	58,195	-	901,811	513,227
12	449.1	(Less) Provision for Rate Refunds	-		-								-	-
13		TOTAL REVENUE NET OF REFUND PROVISION	1,415,038	-	1,415,038	592,869	46,807	25,891	147,830	30,219	58,195	-	901,811	513,227
14		OTHER OPERATING REVENUES												
15	450	Forfeited Discounts	-	-	-	-	-	-	-	-	-	-	-	-
16	451	Miscellaneous Service Revenues	44,080	-	44,080	-	-	-	-	39,349	-	-	39,349	4,731
17	453	Sales of Water and Water Power	-	-	-	-	-	-	-	-	-	-	-	-
18	454	Rent from Electric Property	6,227	-	6,227	-	-	-	-	-	-	-	-	6,227
19	455	Interdepartmental Rents	-	-	-	-	-	-	-	-	-	-	-	-
20	456	Deferred Fuel Revenue	27,043	-	27,043	27,043	-	-	-	-	-	-	27,043	-
21	456	Unbilled Revenue	-	-	-	-	-	-	-	-	-	-	-	-
22	456	Other Electric Revenues (In Detail)	15,352	-	15,352	-	-	-	-	-	-	-	-	15,352
23		TOTAL OTHER OPERATING REVENUES	92,702	-	92,702	27,043	-	-	-	39,349	-	-	66,392	26,310
24		TOTAL ELECTRIC OPERATING REVENUES	1,507,740	-	1,507,740	619,912	46,807	25,891	147,830	69,568	58,195	-	968,203	539,537

Supporting Schedules:

Recap Schedules: C-1, C-21

Schedule C-5 | OPERATING REVENUES DETAIL | Page 3 of 3

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

EXPLANATION: Provide a schedule of operating revenue by primary account for the test year. Provide the per books amounts and the adjustments required to adjust the per books amounts to reflect the requested test year operating revenues.

Type of Data Shown:
____Projected Test Year Ended 12/31/14
____Pr or Year Ended 12/31/13
_X_Historical Year Ended 12/31/12
Witness: S. D. Ritenour

DOCKET NO.: 130140-EI

($000's)

(1) Line No.	(2) Acct No.	(3) Account Title	(4) Per Books	(5) Non-Utility	(6) Electric Utility (4)-(5)	Adjustments (7) Fuel	(8) PPCC	(9) ECCR	(10) ECRC	(11) Franchise Fees & GRT	(12) UPS	(13) Other	(14) Total (7) thru (13)	(15) Adjusted Total (6)-(14)
1		SALES OF ELECTRICITY												
2	440	Residential Sales	603,349	-	603,349	208,335	19,263	11,671	65,285	15,045	-	-	319,599	283,750
3	442	Commercial Sales	386,271	-	386,271	158,765	11,188	9,405	48,761	9,630	-	-	237,749	148,522
4	442	Industrial Sales	139,028	-	139,028	69,765	4,195	4,066	21,280	3,465	-	-	102,771	36,257
5	444	Public Street & Highway Lighting	4,577	-	4,577	1,051	35	58	312	114	-	-	1,570	3,007
6	445	Other Sales to Public Authorities	-	-	-	-	-	-	-	-	-	-	-	-
7	446	Sales to Railroads & Railways	-	-	-	-	-	-	-	-	-	-	-	-
8	448	Interdepartmental Sales	-	-	-	-	-	-	-	-	-	-	-	-
9		Total Sales to Ultimate Consumers	1,133,225	-	1,133,225	437,916	34,681	25,200	135,638	28,254	-	-	661,689	471,536
10	447	Sales for Resale	231,088	-	231,088	144,571	399		4,132		59,245		208,347	22,741
11		TOTAL SALES OF ELECTRICITY	1,364,313	-	1,364,313	582,487	35,080	25,200	139,770	28,254	59,245	-	870,036	494,277
12	449.1	(Less) Provision for Rate Refunds	(1,242)		(1,242)								-	(1,242)
13		TOTAL REVENUE NET OF REFUND PROVISION	1,363,071	-	1,363,071	582,487	35,080	25,200	139,770	28,254	59,245	-	870,036	493,035
14		OTHER OPERATING REVENUES												
15	450	Forfeited Discounts	-	-	-	-	-	-	-	-	-	-	-	-
16	451	Miscellaneous Service Revenues	42,184	-	42,184	-	-	-	-	37,762	-	-	37,762	4,422
17	453	Sales of Water and Water Power	-	-	-	-	-	-	-	-	-	-	-	-
18	454	Rent from Electric Property	6,898	-	6,898	-	-	-	-	-	-	-	-	6,898
19	455	Interdepartmental Rents	-	-	-	-	-	-	-	-	-	-	-	-
20	456	Deferred Fuel Revenue	(7,989)	-	(7,989)	(7,989)	-	-	-	-	-	-	(7,989)	-
21	456	Unbilled Revenue	-	-	-	-	-	-	-	-	-	-	-	-
22	456	Other Electric Revenues (In Detail)	35,732	-	35,732	(33)	8,892	(2,325)	12,130	-	-	-	18,664	17,068
23		TOTAL OTHER OPERATING REVENUES	76,825	-	76,825	(8,022)	8,892	(2,325)	12,130	37,762	-	-	48,437	28,388
24		TOTAL ELECTRIC OPERATING REVENUES	1,439,896	-	1,439,896	574,485	43,972	22,875	151,900	66,016	59,245	-	918,473	521,423

Supporting Schedules:

Recap Schedules: C-1, C-21

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: If the test year is PROJECTED, provide the budgeted versus actual operating revenues and expenses by primary account for a historical five year period and the forecasted data for the test year and the prior year.

Type of Data Shown:
_X_ Projected Test Year Ended 12/31/14
_X_ Prior Year Ended 12/31/13
_X_ Historical Years Ended 12/31/09 through 12/31/12
Witness: R. J. McMillan, S.D. Ritenour, R. W. Grove, J.A. McQuagge, P. C. Caldwell, M. D. Neyman, C. J. Erickson, A.G. Strickland

(000's)

(1) Line No.	(2) Acct. No.	(3) Account Title	(4) 2014 Budget	(5) 2013 Budget	(6) 2012 Budget	(7) 2012 Actual	(8) 2011 Budget	(9) 2011 Actual	(10) 2010 Budget	(11) 2010 Actual	(12) 2009 Budget	(13) 2009 Actual
1		Operating Revenues										
2	440	Residential Sales	(682,735)	(629,409)	(649,156)	(603,349)	(684,009)	(649,414)	(679,136)	(701,072)	(719,428)	(639,503)
3	442	Commercial and Industrial Sales	(604,728)	(573,393)	(550,830)	(525,299)	(617,291)	(579,217)	(622,167)	(590,384)	(599,564)	(568,448)
4	444	Public Street and Highway Lighting	(5,939)	(5,813)	(5,829)	(4,577)	(6,287)	(4,436)	(4,628)	(4,437)	(5,128)	(4,448)
5	445	Other Sales to Public Authorities	-	-	-	-	-	-	-	-	-	-
6	447	Sales for Resale	(209,872)	(206,423)	(198,036)	(231,088)	(190,396)	(245,741)	(177,873)	(219,300)	(257,716)	(130,368)
7	448	Interdepartmental Sales	-	-	-	-	-	-	-	-	-	-
8	449	(Less) Provision for Rate Refund	-	-	-	1,242	-	525	-	14	-	134
9	451	Misc Service Revenues	(47,036)	(44,080)	(42,487)	(42,184)	(43,652)	(44,940)	(44,659)	(44,663)	(45,730)	(41,826)
10	454	Rent from Electric Property	(6,331)	(6,227)	(5,983)	(6,897)	(5,699)	(5,782)	(5,467)	(5,499)	(5,504)	(5,407)
11	455	Interdepartmental Rent	-	-	-	-	-	-	-	-	-	-
12	456	Other Electric Revenues	(15,804)	(42,395)	(4,860)	(27,744)	(5,152)	9,052	(12,382)	(25,028)	36,076	87,433
13		Total Operating Revenues	(1,572,445)	(1,507,740)	(1,457,181)	(1,439,896)	(1,552,486)	(1,519,953)	(1,546,312)	(1,590,369)	(1,596,994)	(1,302,433)
14		Production Expenses										
15	500	Operation,Supervision & Engineering	11,826	10,602	11,114	7,946	10,789	7,939	9,764	8,659	9,512	7,032
16	501	Fuel Expense	310,081	299,180	290,406	266,472	506,276	401,397	549,955	529,208	600,886	363,253
17	502	Steam Expenses	20,435	20,076	19,303	16,861	24,366	14,446	23,959	16,126	13,772	7,014
18	505	Electric Expense	4,131	4,105	3,733	3,404	4,662	3,505	5,073	3,772	5,463	3,381
19	506	Misc Steam Power Expense	18,756	18,038	17,974	20,092	19,035	21,722	20,407	22,861	18,762	17,214
20	507	Rents	-	-	-	-	-	-	-	-	-	-
21	509	Allowances	670	1,023	2,464	1,268	-	3,980	12,881	11,386	32,418	18,903
22	546	Operation,Supervision & Engineering	1,718	1,687	1,789	875	402	887	413	861	399	582
23	547	Fuel Expense - Other Production	310,819	291,863	246,283	277,056	154,325	256,838	125,844	201,331	160,551	190,964
24	548	Generation Expenses	528	554	573	913	689	784	757	859	770	977
25	549	Misc Other Power Generation Expense	1,278	826	776	666	768	749	785	302	310	146
26		Total Production Operation	680,243	647,953	594,416	595,553	721,312	712,247	749,838	795,365	842,843	609,466

27 Totals may not add due to rounding.

Supporting Schedules:

Recap Schedules: C-9

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: If the test year is PROJECTED, provide the budgeted versus actual operating revenues and expenses by primary account for a historical five year period and the forecasted data for the test year and the prior year.

Type of Data Shown:
___ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
_X_ Historical Year Ended 12/31/08

Witness: R. J. McMillan, S.D. Ritenour, R. W. Grove, J.A. McQuagge, P. C. Caldwell, M. D. Neyman, C. J. Erickson, A.G. Strickland

(000's)

(1) Line No.	(2) Acct. No.	(3) Account Title	(4) 2008 Budget	(5) 2008 Actual
1		Operating Revenues		
2	440	Residential Sales	(612,490)	(562,921)
3	442	Commercial and Industrial Sales	(473,720)	(513,906)
4	444	Public Street and Highway Lighting	(4,667)	(3,774)
5	445	Other Sales to Public Authorities	-	-
6	447	Sales for Resale	(222,511)	(199,910)
7	448	Interdepartmental Sales	-	-
8	449	(Less) Provision for Rate Refund	-	50
9	451	Misc Service Revenues	(39,179)	(38,441)
10	454	Rent from Electric Property	(5,006)	(5,435)
11	455	Interdepartmental Rent	-	-
12	456	Other Electric Revenues	31,703	(63,037)
13		Total Operating Revenues	(1,325,870)	(1,387,374)
14		Production Expenses		
15	500	Operation,Supervision & Engineering	10,018	9,919
16	501	Fuel Expense	404,964	437,672
17	502	Steam Expenses	7,334	8,315
18	505	Electric Expense	5,157	4,089
19	506	Misc Steam Power Expense	16,016	15,067
20	507	Rents	-	-
21	509	Allowances	8,002	6,465
22	546	Operation,Supervision & Engineering	361	536
23	547	Fuel Expense - Other Production	187,866	191,136
24	548	Generation Expenses	1,028	961
25	549	Misc Other Power Generation Expense	325	129
26		Total Production Operation	641,071	674,289
27		Totals may not add due to rounding.		

Supporting Schedules:

Recap Schedules: C-9

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: If the test year is PROJECTED, provide the budgeted versus actual operating revenues and expenses by primary account for a historical five year period and the forecasted data for the test year and the prior year.

Type of Data Shown:
_X_ Projected Test Year Ended 12/31/14
_X_ Prior Year Ended 12/31/13
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(000's)

(1) Line No.	(2) Acct. No.	(3) Account Title	(4) 2014 Budget	(5) 2013 Budget	(6) 2012 Budget	(7) 2012 Actual	(8) 2011 Budget	(9) 2011 Actual	(10) 2010 Budget	(11) 2010 Actual	(12) 2009 Budget	(13) 2009 Actual
1	510	Maintenance,Supervision & Engineering	9,889	9,240	9,086	6,413	9,292	6,260	8,435	7,014	7,572	6,764
2	511	Maintenance of Structures	8,489	6,539	6,390	6,674	5,386	6,145	4,569	5,650	4,861	3,791
3	512	Maintenance of Boiler Plant	34,627	24,762	33,399	28,811	36,227	38,987	28,579	26,301	26,065	24,856
4	513	Maintenance of Electric Plant	9,089	5,149	15,910	11,504	11,705	11,128	6,828	6,093	7,340	6,357
5	514	Maintenance of Misc Steam Plant	3,629	3,517	2,619	6,166	2,554	4,196	2,392	3,176	2,168	3,187
6	551	Maint.,Supervision & Engineering-Other	296	288	349	68	673	29	591	134	651	152
7	552	Maintenance of Structures	-	-	77	237	3	131	1	413	1	333
8	553	Maint.of Generation & Elec.Equip.	6,665	7,334	5,158	6,529	4,861	6,846	4,503	7,311	3,183	2,692
9	554	Maint.of Misc.Other Power Gen.Plant	545	205	224	104	425	157	127	124	52	113
10		Total Production Maintenance	73,229	57,033	73,213	66,506	71,126	73,679	56,025	56,216	51,893	48,245
11	555	Purchased & Interchanged Power	88,019	73,216	83,775	74,086	109,667	90,494	119,099	97,227	129,077	91,982
12	556	System Control & Load Dispatch	1,817	1,640	1,703	1,562	1,865	1,677	1,603	1,620	1,779	1,399
13	557	Other Production Expenses	2,309	2,195	2,591	2,313	2,555	2,141	2,492	2,327	2,200	2,884
14		Total Other Power Supply	92,145	77,051	88,069	77,961	114,087	94,312	123,194	101,174	133,056	96,265
15		Total Production	845,617	782,038	755,698	740,020	906,525	880,438	929,057	952,755	1,027,792	753,976
18		Transmission Expenses										
17	560	Operation Supervision & Engineering	1,625	1,510	1,664	1,606	1,090	1,068	1,083	975	1,218	922
18	561	Load Dispatching	3,526	3,366	3,439	2,920	3,455	2,901	3,069	2,918	3,019	2,819
19	562	Station Expenses	44	43	296	84	237	(709)	204	48	75	69
20	563	Overhead Line Expenses	191	165	144	46	248	1,198	413	141	405	(55)
21	564	Underground Line Expenses	-	-	-	-	-	-	-	-	-	-
22	565	Trans-Trans of Elec by Others	102	102	24	153	300	77	300	150	500	147
23	566	Misc.Transmission Expenses	1,038	981	1,103	1,274	1,633	1,193	824	979	822	885
24	567	Rents	13,386	9,812	6,106	5,508	2,521	2,497	2,525	2,531	312	1,487
25		Total Operation	19,911	15,980	12,776	11,591	9,484	8,225	8,418	7,742	6,351	6,274

26 Totals may not add due to rounding.

Supporting Schedules:

Recap Schedules: C-9

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: If the test year is PROJECTED, provide the budgeted versus actual operating revenues and expenses by primary account for a historical five year period and the forecasted data for the test year and the prior year.

Type of Data Shown:
___ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
_X_ Historical Year Ended 12/31/08

Witness: R. J. McMillan, S.D. Ritenour, R. W. Grove, J.A. McQuagge, P. C. Caldwell, M. D. Neyman, C. J. Erickson, A.G. Strickland

(000's)

(1) Line No.	(2) Acct. No.	(3) Account Title	(4) 2008 Budget	(5) 2008 Actual
1	510	Maintenance,Supervision & Engineering	7,614	7,756
2	511	Maintenance of Structures	4,106	3,602
3	512	Maintenance of Boiler Plant	24,841	25,253
4	513	Maintenance of Electric Plant	7,947	9,489
5	514	Maintenance of Misc Steam Plant	2,231	3,096
6	551	Maint.,Supervision & Engineering-Other	430	167
7	552	Maintenance of Structures	31	75
8	553	Maint.of Generation & Elec.Equip.	3,375	3,452
9	554	Maint.of Misc.Other Power Gen.Plant	61	40
10		Total Production Maintenance	50,636	52,930
11	555	Purchased & Interchanged Power	76,616	109,340
12	556	System Control & Load Dispatch	2,465	1,736
13	557	Other Production Expenses	1,971	1,864
14		Total Other Power Supply	81,052	112,940
15		Total Production	772,759	840,159
16		Transmission Expenses		
17	560	Operation Supervision & Engineering	1,077	928
18	561	Load Dispatching	3,223	3,023
19	562	Station Expenses	98	78
20	563	Overhead Line Expenses	431	675
21	564	Underground Line Expenses	-	-
22	565	Recoverable Energy Expenses	600	238
23	566	Misc.Transmission Expenses	696	930
24	567	Rents	311	319
25		Total Operation	6,436	6,191
26		Totals may not add due to rounding.		

Supporting Schedules:

Recap Schedules: C-9

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: If the test year is PROJECTED, provide the budgeted versus actual operating revenues and expenses by primary account for a historical five year period and the forecasted data for the test year and the prior year.

Type of Data Shown:
_X_ Projected Test Year Ended 12/31/14
_X_ Prior Year Ended 12/31/13
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(000's)

(1) Line No.	(2) Acct. No.	(3) Account Title	(4) 2014 Budget	(5) 2013 Budget	(6) 2012 Budget	(7) 2012 Actual	(8) 2011 Budget	(9) 2011 Actual	(10) 2010 Budget	(11) 2010 Actual	(12) 2009 Budget	(13) 2009 Actual
1	568	Maintenance,Supervision & Engineering	1,053	1,005	1,029	869	1,021	774	873	621	745	493
2	569	Maintenance of Structures	1,012	788	721	488	572	543	496	389	446	252
3	570	Maintenance of Substation Equipment	830	814	871	738	847	1,585	801	996	721	616
4	571	Maint.of Overhead Lines	4,479	3,290	2,645	2,823	2,351	3,822	1,570	2,396	1,316	1,583
5	572	Maintenance of Underground Lines	-	-	-	112	-	15	-	-	-	-
6	573	Maint.of Misc.Transmission Lines	102	113	139	95	144	106	147	105	166	137
7		Total Maintenance	7,475	6,010	5,404	5,125	4,935	6,845	3,887	4,507	3,394	3,081
8		Total Transmission	27,386	21,990	18,181	16,716	14,419	15,070	12,305	12,249	9,745	9,355
9		Distribution Expenses										
10	580	Operation Supervision & Engineering	6,860	6,257	5,748	5,314	5,941	5,348	5,731	5,294	5,946	4,928
11	581	Load Dispatching	902	865	771	693	745	732	628	617	657	596
12	582	Station Expenses	308	307	419	287	447	251	393	256	422	197
13	583	Overhead Line Expenses	2,712	2,719	2,708	3,086	2,805	3,041	2,937	2,658	2,221	2,913
14	564	Underground Line Expenses	739	741	886	873	860	898	995	906	667	848
15	585	Street Lighting & Signal System Exp	598	598	595	546	594	662	487	640	342	710
16	586	Meter Expenses	2,627	2,658	3,538	2,756	3,668	3,153	3,522	3,295	3,519	3,113
17	587	Customer Installation Expense	1,331	1,383	1,108	969	728	816	746	821	747	758
18	588	Misc.Distribution Expense	4,384	4,301	4,247	4,130	4,829	4,581	3,273	3,222	3,427	2,876
19	589	Rents	-	-	-	-	22	-	22	-	22	-
20		Total Operation	20,461	19,829	20,019	18,654	20,639	19,482	18,734	17,709	17,970	16,939
21		Totals may not add due to rounding.										

Supporting Schedules:

Recap Schedules: C-9

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

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(000's)

(1) Line No.	(2) Acct. No.	(3) Account Title	(4) 2008 Budget	(5) 2008 Actual
1	568	Maintenance,Supervision & Engineering	851	641
2	569	Maintenance of Structures	210	117
3	570	Maintenance of Substation Equipment	635	629
4	571	Maint.of Overhead Lines	1,321	1,074
5	572	Maintenance of Underground Lines	-	-
6	573	Maint.of Misc.Transmission Lines	145	182
7		Total Maintenance	3,162	2,643
8		Total Transmission	9,598	8,834
9		Distribution Expenses		
10	580	Operation Supervision & Engineering	6,174	5,986
11	581	Load Dispatching	979	619
12	582	Station Expenses	309	344
13	583	Overhead Line Expenses	1,816	2,329
14	584	Underground Line Expenses	1,189	1,032
15	585	Street Lighting & Signal System Exp	332	775
16	586	Meter Expenses	2,945	3,215
17	587	Customer Installation Expense	548	717
18	588	Misc.Distribution Expense	2,350	2,213
19	589	Rents	19	-
20		Total Operation	16,661	17,230
21		Totals may not add due to rounding.		

Supporting Schedules:

Recap Schedules: C-9

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

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(000's)

(1) Line No.	(2) Acct. No.	(3) Account Title	(4) 2014 Budget	(5) 2013 Budget	(6) 2012 Budget	(7) 2012 Actual	(8) 2011 Budget	(9) 2011 Actual	(10) 2010 Budget	(11) 2010 Actual	(12) 2009 Budget	(13) 2009 Actual
1	590	Maintenance,Supervision & Engineering	3,664	3,393	3,103	2,929	3,538	3,003	3,460	2,974	3,296	2,699
2	591	Maintenance of Structures	3,364	2,253	2,141	2,710	2,001	2,170	1,723	1,844	1,681	1,817
3	592	Maintenance of Substation Equipment	962	952	1,033	998	1,035	1,338	1,319	1,180	1,254	1,120
4	593	Maint.of Overhead Lines	13,075	12,630	12,538	11,245	12,086	13,000	10,543	11,888	9,455	10,448
5	594	Maintenance of Underground Lines	1,897	1,902	1,789	2,138	1,792	2,071	1,864	2,371	2,204	2,189
6	595	Maint.of Line Transformers	1,087	1,087	880	905	870	1,069	980	802	598	791
7	596	Maint.of Street Lighting & Signal Sys.	597	599	599	547	598	515	556	446	329	489
8	597	Maintenance of Meters	159	158	155	160	134	154	134	177	118	155
9	598	Maint.of Misc.Distribution Plant	472	531	499	420	464	489	490	426	594	457
10		Total Maintenance	25,277	23,504	22,737	22,052	22,518	23,809	21,069	22,108	19,529	20,165
11		Total Distribution	45,738	43,333	42,757	40,706	43,157	43,291	39,803	39,817	37,499	37,104
12		Customer Accounts Expenses										
13	901	Customer Accounts Supervision	618	604	429	506	387	430	322	443	572	494
14	902	Meter Reading Expenses	1,533	1,520	1,000	1,565	2,628	2,208	2,518	2,641	2,406	2,567
15	903	Customer Records & Collection Expense	18,327	17,829	17,479	15,332	16,151	14,411	14,999	13,539	14,770	13,328
16	904	Uncollectible Accounts	3,809	3,233	3,508	2,611	4,306	3,333	4,807	3,907	3,543	3,753
17	905	Misc.Customer Accounts Expense	1,564	1,412	1,287	1,186	1,295	1,322	1,154	1,191	1,216	1,101
18		Total Customer Accounts	25,850	24,598	23,704	21,200	24,767	21,704	23,800	21,721	22,507	21,243
19		Customer Service and Information										
20	907	Cust.Srv. and Information Supervision	1,829	1,877	1,927	1,650	3,240	1,736	3,291	2,086	3,070	2,121
21	908	Customer Assistance Expense	34,300	33,818	34,131	34,961	31,107	26,374	23,400	17,912	20,371	25,632
22	909	Information & Institutional Adv.	2,283	2,283	2,251	1,131	1,788	1,913	1,803	1,225	1,679	1,955
23	910	Misc.Customer Service & Info Exp.	189	187	85	75	75	65	89	65	91	65
24		Total Customer Serv. and Information	38,602	38,166	38,394	37,817	38,210	30,088	28,583	21,288	25,211	29,773
25		Totals may not add due to rounding.										

Supporting Schedules:

Recap Schedules: C-9

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

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(000's)

(1) Line No.	(2) Acct. No.	(3) Account Title	(4) 2008 Budget	(5) 2008 Actual
1	590	Maintenance,Supervision & Engineering	3,473	3,224
2	591	Maintenance of Structures	1,597	1,746
3	592	Maintenance of Substation Equipment	1,195	1,772
4	593	Maint.of Overhead Lines	9,291	9,233
5	594	Maintenance of Underground Lines	1,889	1,783
6	595	Maint.of Line Transformers	638	882
7	596	Maint.of Street Lighting & Signal Sys.	372	425
8	597	Maintenance of Meters	125	149
9	598	Maint.of Misc.Distribution Plant	502	497
10		Total Maintenance	19,082	19,711
11		Total Distribution	35,743	36,941
12		Customer Accounts Expenses		
13	901	Customer Accounts Supervision	377	374
14	902	Meter Reading Expenses	2,358	2,522
15	903	Customer Records & Collection Expense	14,675	13,855
16	904	Uncollectible Accounts	2,594	3,850
17	905	Misc.Customer Accounts Expense	1,198	1,272
18		Total Customer Accounts	21,202	21,873
19		Customer Service and Information		
20	907	Cust.Srv. and Information Supervision	3,142	3,067
21	908	Customer Assistance Expense	18,290	20,862
22	909	Information & Institutional Adv.	1,601	1,539
23	910	Misc.Customer Service & Info Exp.	265	247
24		Total Customer Serv. and Information	23,298	25,715
25		Totals may not add due to rounding.		

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

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(000's)

(1) Line No.	(2) Acct. No.	(3) Account Title	(4) 2014 Budget	(5) 2013 Budget	(6) 2012 Budget	(7) 2012 Actual	(8) 2011 Budget	(9) 2011 Actual	(10) 2010 Budget	(11) 2010 Actual	(12) 2009 Budget	(13) 2009 Actual
1		Sales Expenses										
2	911	Sales Supervision	-	-	-	-	-	-	-	-	-	-
3	912	Demonstration & Selling Expense	1,391	1,378	1,082	993	1,085	1,149	948	1,061	1,027	878
4	913	Advertising & Promotional Expense	-	-	-	-	-	-	-	-	-	-
5		Total Sales Expense	1,391	1,378	1,082	993	1,085	1,149	948	1,061	1,027	878
6		Administrative & General Expenses										
7	920	Administrative & General Salaries	16,442	15,899	14,566	15,102	14,360	14,225	13,289	13,738	12,798	11,383
8	921	Office Supplies & Expenses	4,120	4,037	3,940	3,702	3,926	5,338	3,645	3,728	3,559	2,823
9	922	Admin.Expense Transferred (Credit)	(342)	(333)	(320)	(331)	(324)	(311)	(344)	(332)	(304)	(338)
10	923	Outside Services Employed	19,051	18,163	19,724	17,760	19,840	18,605	18,495	18,817	18,095	15,488
11	924	Property Insurance	7,967	7,487	7,535	7,262	7,398	7,008	7,643	7,319	20,130	17,867
12	925	Injuries and Damages	3,162	3,117	3,001	2,923	2,869	2,893	2,847	2,899	2,730	2,766
13	926	Employee Pension and Benefits	27,049	25,880	23,332	20,273	18,730	15,287	18,194	16,613	17,878	16,556
14	927	Franchise Requirements	-	-	-	-	-	-	-	-	-	-
15	928	Regulatory Commission Expense	2,149	2,091	1,940	2,532	1,284	2,003	1,163	1,389	1,196	1,231
16	929	Duplicate Charges (Credit)	(1,054)	(1,027)	(865)	(1,357)	(1,065)	(1,211)	(2,306)	(1,311)	(2,078)	(2,122)
17	930	Misc.General & Advertising Expenses	9,489	9,320	(536)	7,047	7,797	7,592	9,054	7,683	6,268	6,741
18	931	Rents	276	388	325	361	325	320	298	314	627	582
19		Total Operation	88,309	85,023	72,641	75,274	75,140	71,749	71,978	70,857	80,899	72,977
20	935	Admin.& General Maintenance	687	724	605	621	515	786	541	544	646	562
21		Total Administrative & General	88,996	85,747	73,246	75,895	75,655	72,535	72,519	71,401	81,545	73,539
22		Total Operation & Maintenance	1,073,580	997,250	953,061	933,347	1,101,818	1,064,275	1,107,015	1,120,292	1,205,326	925,868
23		Totals may not add due to rounding.										

Supporting Schedules:

Recap Schedules: C-9

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: If the test year is PROJECTED, provide the budgeted versus actual operating revenues and expenses by primary account for a historical five year period and the forecasted data for the test year and the prior year.

Type of Data Shown:
___ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
_X_ Historical Year Ended 12/31/08
Witness: R. J. McMillan, S.D. Ritenour, R. W. Grove, J.A. McQuagge, P. C. Caldwell, M. D. Neyman, C. J. Erickson, A.G. Strickland

(000's)

(1) Line No.	(2) Acct. No.	(3) Account Title	(4) 2008 Budget	(5) 2008 Actual
1		Sales Expenses		
2	911	Sales Supervision	-	-
3	912	Demonstration & Selling Expense	1,120	1,116
4	913	Advertising & Promotional Expense		-
5		Total Sales Expense	1,120	1,116
6		Administrative & General Expenses		
7	920	Administrative & General Salaries	12,213	11,799
8	921	Office Supplies & Expenses	3,772	3,616
9	922	Admin.Expense Transferred (Credit)	(300)	(314)
10	923	Outside Services Employed	18,697	15,659
11	924	Property Insurance	33,104	33,095
12	925	Injuries and Damages	2,748	2,631
13	926	Employee Pension and Benefits	18,389	15,524
14	927	Franchise Requirements	-	-
15	928	Regulatory Commission Expense	1,070	1,012
16	929	Duplicate Charges (Credit)	(1,855)	(2,517)
17	930	Misc.General & Advertising Expenses	5,792	6,632
18	931	Rents	51	255
19		Total Operation	93,681	87,392
20	935	Admin.& General Maintenance	574	594
21		Total Administrative & General	94,255	87,986
22		Total Operation & Maintenance	957,975	1,022,624
23		Totals may not add due to rounding.		

Supporting Schedules:

Recap Schedules: C-9

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: If the test year is PROJECTED, provide the budgeted versus actual operating revenues and expenses by primary account for a historical five year period and the forecasted data for the test year and the prior year.

Type of Data Shown:
_X_ Projected Test Year Ended 12/31/14
_X_ Prior Year Ended 12/31/13
_X_ Historical Years Ended 12/31/09 through 12/31/12
Witness: R. J. McMillan, S.D. Ritenour, R. W. Grove, J.A. McQuagge, P. C. Caldwell, M. D. Neyman, C. J. Erickson, A.G. Strickland

(000's)

(1) Line No.	(2) Acct. No.	(3) Account Title	(4) 2014 Budget	(5) 2013 Budget	(6) 2012 Budget	(7) 2012 Actual	(8) 2011 Budget	(9) 2011 Actual	(10) 2010 Budget	(11) 2010 Actual	(12) 2009 Budget	(13) 2009 Actual
1		Other Operating Expenses										
2	403	Depreciation Expense	149,469	144,379	136,266	134,778	125,315	124,093	111,734	118,487	92,501	90,965
3	404	Amortization of Limited Plant	5,843	6,184	6,261	6,237	5,793	5,817	3,854	3,826	3,501	3,577
4	406	Amortization of Plant Acquisition Adj.	-	-	-	-	-	-	-	-	-	-
5	407	Amort. of Property Losses	1,213	1,213	991	1,132	324	673	45	183	88	(72)
6	408	Taxes Other than Income Taxes	111,773	103,988	100,777	97,313	102,166	101,302	102,126	101,778	102,035	94,506
7	409	Current Income Tax - Operating Inc./Loss	48,814	33,784	(92,575)	(94,779)	(13,962)	(15,612)	40,682	(12,253)	89,289	71,983
8	410	Provision for Deferred Income Tax	38,207	65,821	181,457	297,298	93,981	177,591	42,419	189,298	36,395	95,994
9	411	Provision for Deferred Income Tax (CR)	(19,853)	(22,629)	(11,578)	(122,977)	(18,821)	(98,474)	(18,891)	(104,246)	(71,385)	(112,535)
10	411	Accretion	-	-	0	508	-	545	-	656	-	642
11	411	Investment Tax Credit (Net)	(1,224)	(1,304)	(1,304)	(1,352)	(1,349)	(1,349)	(1,548)	(1,544)	(1,608)	(1,603)
12	411	Gains from Disp. Of Utility Plant	-	-	-	-	-	-	-	(6)	-	-
13	411	Losses from Disp. Of Utility Plant	-	-	-	-	-	-	-	-	-	-
14	411	Gains from Dispostion of Allowances	(172)	(244)	(264)	(265)	(108)	(128)	(77)	(110)	(73)	(112)
15		Total Other Operating Expenses	334,070	331,192	320,031	317,893	293,339	294,458	280,344	296,069	250,743	243,345

16 Totals may not add due to rounding.

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: If the test year is PROJECTED, provide the budgeted versus actual operating revenues and expenses by primary account for a historical five year period and the forecasted data for the test year and the prior year.

Type of Data Shown:
___ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
_X_ Historical Year Ended 12/31/08
Witness: R. J. McMillan, S.D. Ritenour, R. W. Grove, J.A. McQuagge, P. C. Caldwell, M. D. Neyman, C. J. Erickson, A.G. Strickland

(000's)

(1) Line No.	(2) Acct. No.	(3) Account Title	(4) 2008 Budget	(5) 2008 Actual
1		Other Operating Expenses		
2	403	Depreciation Expense	87,907	87,200
3	404	Amortization of Limited Plant	3,001	2,992
4	406	Amortization of Plant Acquisition Adj.	-	-
5	407	Amort. of Property	153	(47)
6	408	Taxes Other than Income Taxes	89,127	87,246
7	409	Current Income Tax - Operating Inc./Loss	76,946	32,723
8	410	Provision for Deferred Income Tax	18,855	82,520
9	411	Provision for Deferred Income Tax (CR)	(42,960)	(60,906)
10	411	Accretion	-	631
11	411	Investment Tax Credit (Net)	(1,728)	(1,732)
12	411	Gains from Disp. Of Utility Plant	-	(732)
13	411	Losses from Disp. Of Utility Plant	-	25
14	411	Gains from Dispostion of Allowances	(99)	(418)
15		Total Other Operating Expenses	231,202	229,502
16		Totals may not add due to rounding.		

Supporting Schedules:

Recap Schedules: C-9

Schedule C-7	OPERATION AND MAINTENANCE EXPENSES - TEST YEAR	Page 1 of 1
FLORIDA PUBLIC SERVICE COMMISSION COMPANY: GULF POWER COMPANY DOCKET NO.: 130140-EI	EXPLANATION: If the requested revenue requirements are based on a historical test year, provide actual monthly operation and maintenance expense by primary account for the test year.	Type of Data Shown: _X_ Projected Test Year Ended 12/31/14 ____ Prior Year Ended 12/31/13 ____ Historical Year Ended 12/31/12 Witness: R. J. McMillan

(1) Line No.	(2)
1	Not applicable, requested revenue requirements are based on projected test year, not historical.

Supporting Schedules:

Recap Schedules:

Schedule C-8 | DETAIL OF CHANGES IN EXPENSES | Page 1 of 1

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide the changes in primary accounts that exceed 1/20th of one percent (.0005) of total operating expenses and ten percent from the prior year to the test year. Quantify each reason for the change.

Type of Data Shown:
X Projected Test Year Ended 12/31/14
X Prior Year Ended 12/31/13
__ Historical Year Ended 12/31/12
Witness: P. C. Caldwell, C. J. Erickson, R. W. Grove, J. A. McQuagge

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
					Increase/(Decrease)		
Line No.	Acct. No.	Account	Test Year Ended 12/31/14	Prior Year Ended 12/31/13	Dollars (4)-(5) (000's)	Percent (6)/(5) (%)	Reason(s) for Change
1	409/410/411	Income Taxes - Utility Operating Income	67,168	76,976	(9,808)	-12.74%	See Note 1
2	500	Steam Power Op. - Supervision & Engineering	11,826	10,602	1,224	11.54%	See Note 2
3	511	Steam Power Maintenance - Structures	8,489	6,539	1,950	29.82%	See Note 3
4	512	Steam Power Maintenance - Boiler Plant	34,627	24,762	9,865	39.84%	See Note 4
5	513	Steam Power Maintenance - Electric Plant	9,089	5,149	3,940	76.52%	See Note 5
6	555	Purchased Power	88,019	73,216	14,803	20.22%	See Note 6
7	567	Transmission Operation - Rents	13,386	9,812	3,574	36.42%	See Note 7
8	571	Transmission Maintenance - Overhead Lines	4,479	3,290	1,189	36.14%	See Note 8
9	591	Distribution Maintenance - Structures	3,364	2,253	1,111	49.31%	See Note 9

10 Note 1 : $9,809,000 decrease is primarily due to the decrease in pre-tax net income.
11 Note 2 : $371,000 increase in Daniel baseline expenses, $505,000 increase in services such as IT Support, Business Application Support, Corporate Services, Technology
12 Development and Legal Services and $185,000 increase in miscellaneous expenses.
13 Note 3 : $1,600,000 increase in Selective Catalyctic Reduction expenses and $332,000 increase in Scrubber Expenses - both are recovered through ECRC.
14 Note 4 : Major outages budgeted in 2014 include Plant Crist Units 4, 5 and 6 for $6,638,000 and Plant Daniel Units 1 and 2 for $3,975,000. Expenses recovered through ECRC at
15 Plants Smith and Crist increased by $435,000, Plant Crist Fuel Handling and Maintenance decreased by $875,000, Plant Smith Maintenance decreased by $253,000 and
16 miscellaneous expenses decreased by $55,000.
17 Note 5 : Major outages budgeted in 2014 include Plant Crist Units 4, 5 and 6 for $3,573,000 and Plant Daniel Units 1 and 2 for $439,000.
18 Note 6 : Not included in base rates - recovered through the fuel cost recovery and purchased power capacity cost recovery clauses.
19 Note 7 : $3,574,000 increase in new projects within Transmission Rent 115KV. Certain transmission costs are recovered through the purchased power capacity cost recovery
20 clause.
21 Note 8 : $1,080,000 increase in vegetation management and $108,000 increase in miscellaneous transmission maintenance.
22 Note 9 : $1,105,000 increase in groundwater contamination investigation expenses recovered through ECRC.

Supporting Schedules: | Recap Schedules:

Schedule C-9 | FIVE YEAR ANALYSIS - CHANGE IN COST | Page 1 of 1

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide a schedule showing the change in cost, by functional group, for the last five years.

Type of Data Shown:
_____ Projected Test Year Ended 12/31/14
_____ Prior Year Ended 12/31/13
X Historical Year Ended 12/31/07-12/31/12
Witness: C. J. Erickson, M. D. Neyman
R. W. Grove, P. C. Caldwell, A. G. Strickland

(1) Line No.	(2) Description of Functional Group	(3) Type of Cost	(4) 2012 Dollars (000's)	(5) 2012 Percent Change	(6) 2011 Dollars (000's)	(7) 2011 Percent Change	(8) 2010 Dollars (000's)	(9) 2010 Percent Change	(10) 2009 Dollars (000's)	(11) 2009 Percent Change	(12) 2008 Dollars (000's)	(13) 2008 Percent Change	(14) 2007 Dollars (000's)
1	Fuel	Variable	543,528	-17.43%	658,235	-9.90%	730,539	31.81%	554,217	-11.86%	628,808	11.73%	562,803
2	Interchange	Semi-Variable	74,086	-18.13%	90,494	-6.93%	97,227	5.70%	91,982	-15.88%	109,340	52.94%	71,494
3	Production	Semi-Variable	122,406	-7.06%	131,709	5.38%	124,989	15.97%	107,777	5.65%	102,011	6.53%	95,759
4	Transmission	Semi-Variable	16,716	10.92%	15,070	23.03%	12,249	30.93%	9,355	5.90%	8,834	-10.79%	9,903
5	Distribution	Semi-Variable	40,706	-5.97%	43,291	8.72%	39,817	7.31%	37,104	0.44%	36,941	-4.79%	38,798
6	Customer Account	Semi-Variable	21,200	-2.32%	21,704	-0.08%	21,721	2.25%	21,243	-2.88%	21,873	-2.29%	22,386
7	Customer Service & Information & Sales	Semi-Variable	38,810	24.24%	31,237	39.77%	22,349	-27.09%	30,651	14.24%	26,831	6.74%	25,137
8	Administrative and General	Semi-Variable	75,895	4.63%	72,535	1.59%	71,401	-2.92%	73,539	-16.42%	87,986	-1.28%	89,130
9	Depreciation	Fixed	141,038	8.78%	129,651	6.72%	121,492	30.08%	93,397	6.23%	87,919	2.69%	85,613
10	Taxes	Semi-Variable	176,855	7.31%	164,807	-5.60%	174,577	16.43%	149,948	5.91%	141,583	8.39%	130,620
11	Interest (without AFUDC)	Semi-Variable	62,749	1.04%	62,101	13.38%	54,771	14.47%	47,847	1.65%	47,071	2.94%	45,728
12	TOTAL		1,313,989	-7.52%	1,420,834	-3.42%	1,471,132	20.88%	1,217,060	-6.32%	1,299,197	10.35%	1,177,371

Supporting Schedules: C-6

Recap Schedules:

Schedule C-10 | DETAIL OF RATE CASE EXPENSES FOR OUTSIDE CONSULTANTS | Page 1 of 1

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide a detailed breakdown of rate case expenses by service provided for each outside consultant, attorney, engineer or other consultant providing professional services for the case.

Type of Data Shown:
___ Projected Test Year Ended 12/31/14
X Prior Year Ended 12/31/13
___ Historical Year Ended 12/31/12
Witness: C. J. Erickson

(1) Line No.	(2) Vendor Name	(3) Counsel, Consultant, or Witness	(4) Specific Services Rendered	(5) Fee ($)	(6) Basis of Charge	(7) Travel Expenses ($)	(8) Other ($)	(9) Total (5+7+8) ($)	(10) Type of Services (A)
	OUTSIDE CONSULTANTS								
1	Various	Consultant/	Accounting, Cost of Capital,	1,186,000	Contract	-	-	1,186,000	A, B, S, R, O
2		Witness	Cost of Service, Rate Design, Other						
	OUTSIDE LEGAL SERVICES								
3	Various	Counsel	Legal Services	2,878,000	Contract	-	-	2,878,000	L

4 (A) TYPE OF SERVICE
5 A = ACCOUNTING
6 B = COST OF CAPITAL
7 C = ENGINEERING
8 L = LEGAL
9 O = OTHER
10 R = RATE DESIGN
11 S = COST OF SERVICE

SCHEDULE OF RATE CASE EXPENSE AMORTIZATION IN TEST YEAR

	Rate Case	Total Expenses ($000s)	Rate Order Date	Amortization Period	Unamortized Amount ($000s)	Test Year Amortization ($000s)
12	Docket No. 110138-EI	2,800	PSC-12-0179-FOF-EI	4 years	1,596	399
13	Docket No. 130140-EI	4,922	N/A	4 years	4,922	1,231

Supporting Schedules:

Recap Schedules:

Schedule C-11 | UNCOLLECTIBLE ACCOUNTS | Page 1 of 1

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide the following information concerning bad debts for the four most recent historical years and the test year. In addition, provide a calculation of the bad debt component of the Revenue Expansion Factor.

Type of Data Shown:
X Projected Test Year Ended 12/31/14
Prior Year Ended 12/31/13
X Historical Year Ended 12/31/09-12/31/12

Witness: M. D. Neyman

(1) Line No.	(2) Year	(3) Write-Offs (Retail) (000's)	(4) Gross Revenues From Sales of Electricity (Retail) (000's)	(5) Adjustments to Gross Revenues (Specify) (000's)	(6) Adjusted Gross Revenues (000's)	(7) Bad Debt Factor (3) / (6)
1	2009	4,029	1,212,399	0	1,212,399	0.3323%
2	2010	3,806	1,295,893	0	1,295,893	0.2937%
3	2011	3,384	1,233,067	0	1,233,067	0.2744%
4	2012	3,084	1,133,225	0	1,133,225	0.2721%
5	4 Year Totals	14,303	4,874,584	0	4,874,584	0.2934%
6	2014 Test Year	3,795	1,293,402	0	1,293,402	0.2934%

7 Bad Debt factor based on 4 year average (2009 - 2012) of net write-offs to gross revenue

8 Total Retail Revenue includes lighting, Gross Receipts tax

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide a schedule of jurisdictional administrative, general, customer service, R&D, and other miscellaneous expenses by category and on a per customer basis for the test year and the most recent historical year.

Type of Data Shown:
_X_ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
_X_ Historical Year Ended 12/31/12
Witness: C. J. Erickson, M. D. Neyman
A. G. Strickland

(000's)

(1) Line No.	(2) Jurisdictional Adjusted Administrative Expenses	(3) Test Year Ended 2014	(4) Historical Year Ended 2012	(5) Difference (3) - (4)	(6) Percent Increase/(Decrease) (5)/(4)
1	Total Administrative & General Expenses	87,827	69,390	18,437	27%
2	(Accounts 920 - 935)				
3	Customer Accounts Expenses	25,616	21,054	4,562	22%
4	(Accounts 901 - 905)				
5	Customer Service & Information Expense	16,671	18,288	(1,617)	-9%
6	(Accounts 907 - 910)				
7	Sales Expense	1,144	784	360	46%
8	(Accounts 911 - 916)				
9	Total Jurisdictional Administrative Expenses	131,258	109,516	21,742	20%
10	(Accounts 901 - 935)				
11	Average Number of Customers	443,350	434,440	8,910	2%
12	Administrative Expense per Customer	0.30	0.25	0.05	20%

Supporting Schedules: C-4

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide a schedule of charges to Account 930.2 (Miscellaneous General Expenses) by type of charge for the most recent historical year. Aggregate all charges that do not exceed $100,000 and all similar charges that exceed $100,000.

Type of Data Shown:
____ Projected Test Year Ended 12/31/14
____ Prior Year Ended 12/31/13
X Historical Year Ended 12/31/12
Witness: C. J. Erickson

(1) Line No.	(2) Description	(3) Electric Utility $	(4) Jurisdictional Factor	(5) Jurisdictional Amount $
1	Total Miscellaneous General			
2	Expenses of $100,000 or Less	324,627	0.9783994	317,615
3	Miscellaneous General Expenses			
4	Exceeding $100,000 (Specify)			
5	Industry Association Dues	673,997	0.9783994	659,438
6	Directors Fees & Expenses	200,811	0.9783994	196,473
7	A&G for Joint Ownership	5,310,594	0.9783994	5,195,882
8	Commitment Fees	531,542	0.9783994	520,060
9	Total Miscellaneous General Expenses	7,041,571		6,889,468
10	Average Number of Customers	434,441		434,440
11	Miscellaneous General Expenses Per Customer	16.21		15.86

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide a schedule of advertising expenses by subaccounts for the test year and the most recent historical year for each type of advertising that is included in base rate cost of service.

Type of Data Shown:
X Projected Test Year Ended 12/31/14
Prior Year Ended 12/31/13
Historical Year Ended 12/31/12
Witness: A. G. Strickland

(1) Line No.	(2) Account/ Sub Account Number	Work Order	(3) Account/ Sub Account/ Work Order Title	(4) Projected Year Electric Utility (000's)	(5) NOI Adjustment (000's)	(6) Projected Year Electric Utility Net (000's)	(7) Jurisdictional Factor	(8) Jurisdictional Amount (000's)
1	ACCOUNT 909							
2	ECCR							
3	90900000		CS&I - Info & Instruct Advertising Exp					
4		ME110A	ECCR Residential Energy Audit Advertising	601	(601)	0		
5		ME161A	ECCR Residential Advanced Energy Management Advertising	393	(393)	0		
6		ME162A	ECCR Residential Energy Select Light Advertising	6	(6)	0		
7		ME210A	ECCR Commercial/Industrial Audits Advertising	50	(50)	0		
8			Total ECCR Advertising	1,050	(1,050)	0	0.0000000	0
9	Non-ECCR							
10	90900000		CS&I - Info & Instruct Advertising Exp					
11		GN121A	Corporate Advertising	22	0	22		
12		MN101A	Non-ECCR Residential New Home Market Advertising	226	0	226		
13		MN106A	Non-ECCR Residential Existing Home Market Advertising	183	0	183		
14		MN121A	RS-ESS - Cust Serv	673	0	673		
15		MN188A	Non-ECCR Residential Water Htr Conversions Advertising	20	0	20		
16		MN276A	Non-ECCR Commercial Hospitality Advertising	1	0	1		
17		MN288A	Non-ECCR Commercial EnergyDirect.Com Advertising	4	0	4		
18		MN291A	Non-ECCR Commercial General Advertising	3	0	3		
19		MN346A	Non-ECCR Industrial Lighting Marketing Advertising	100	0	100		
20			Total Non-ECCR Advertising	1,232	0	1,232	1.0000000	1,232
21	Total Account 909			2,282	(1,050)	1,232		1,232
22	ACCOUNT 930							
23	93010155	GN121A	Corporate Advertising	30	(30)	0		
24			Total Account 930.1	30	(30)	0	0.9792787	0
25	Total Advertising Expenses			2,312	(1,080)	1,232		1,232
26	Average Number of Customers			443	443	443		443
27	Advertising Expenses per Customer			5.22	(2.44)	2.78		2.78

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide a schedule of advertising expenses by subaccounts for the test year and the most recent historical year for each type of advertising that is included in base rate cost of service.

Type of Data Shown:
___ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
X Historical Year Ended 12/31/12
Witness: A. G. Strickland

(1) Line No.	(2) Account/ Sub Account Number	Work Order	(3) Account/ Sub Account/ Work Order Title	(4) Historical Year Electric Utility (000's)	(5) NOI Adjustment (000's)	(6) Historical Year Electric Utility Net (000's)	(7) Jurisdictional Factor	(8) Jurisdictional Amount (000's)
1	ACCOUNT 909							
2	ECCR							
3	90900000		CS&I - Info & Instruct Advertising Exp					
4		ME110A	ECCR Residential Energy Audit Advertising	478	(478)	0		
5		ME116A	ECCR Residential Energy Audit Advertising	17	(17)	0		
6		ME118A	ECCR Residentall Mail-In Energy Audit Advertising	10	(10)	0		
7		ME130A	ECCR Residential HVAC Efficiency Advertising	1	(1)	0		
8		ME161A	ECCR Residential Advanced Energy Management Advertising	336	(336)	0		
9		ME216A	ECCR Commercial Energy Aud/Tech Assist Advertising	1	(1)	0		
10		ME230A	ECCR Commercial Building Efficiency Advertising	1	(1)	0		
11			Total ECCR Advertising	844	(844)	0	0.0000000	0
12	Non-ECCR							
13	90900000		CS&I - Info & Instruct Advertising Exp					
14		GN121A	Corporate Advertising	19	0	19		
15		MN101A	Non-ECCR Residential New Home Market Advertising	44	0	44		
16		MN106A	Non-ECCR Residential Existing Home Market Advertising	17	0	17		
17		MN121A	RS-ESS - Cust Serv	199	0	199		
18			Total Non-ECCR Advertising	279	0	279	1.0000000	279
19	Total Account 909			1,123	(844)	279		279
20	ACCOUNT 930							
21	93010155	GN120A	Advertising - Media	1	(1)	0		
22	93010155	GN121A	Corporate Advertising	4	(4)	0		
23			Total Account 930.1	5	(5)	0	0.9792787	0
24	Total Advertising Expenses			1,128	(849)	279		279
25	Average Number of Customers			434	434	434		434
26	Advertising Expenses per Customer			2.60	(1.96)	0.64		0.64

Supporting Schedules: Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide a schedule of Industry association dues included in cost of service by organization for the test year and the most recent historical year. Indicate the nature of each organization. Individual dues less than $10,000 may be aggregated.

Type of Data Shown:

X Projected Test Year Ended 12/31/14

___ Prior Year Ended 12/31/13

___ Historical Year Ended 12/31/12

Witness: C. J. Erickson

(1) Line No.	(2) Name of Organization	(3) Nature of Organization	(4) Electric Utility $	(5) Jurisdictional Factor	(6) Amount $
1	Edison Electric Institute	Business Association	235,328	0.9792787	230,452
2	Florida Electric Power Coordinating Group	Business Association	88,000	0.9792787	86,177
3	Florida Council of 100	Community Development	6,500	0.9792787	6,365
4	North American Electric Reliability Corporation	Business Association	333,540	0.9792787	326,629
5	Southeastern Electric Exchange	Business Association	10,000	0.9792787	9,793
6	Florida Reliability Coordinating Council	Business Association	5,000	0.9792787	4,896
7	Total Industry Association Dues		678,368		664,312
8	Average Number of Customers		443,351		443,350
9	Dues Per Customer		1.53		1.50
10	Lobby Expenses Included in Industry Association Dues		0		0

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide a schedule of industry association dues included in cost of service by organization for the test year and the most recent historical year. Indicate the nature of each organization. Individual dues less than $10,000 may be aggregated.

Type of Data Shown:
___ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
X Historical Year Ended 12/31/12
Witness: C. J. Erickson

(1) Line No.	(2) Name of Organization	(3) Nature of Organization	(4) Electric Utility $	(5) Jurisdictional Factor	(6) Jurisdictional Amount $
1	Edison Electric Institute	Business Association	227,002	0.9792787	222,298
2	Florida Electric Power Coordinating Group	Business Association	102,724	0.9792787	100,595
3	Florida Reliability Coordinating Council	Business Association	5,000	0.9792787	4,896
4	North American Electric Reliability Corporation	Business Association	314,274	0.9792787	307,762
5	Southeastern Electric Exchange	Business Association	8,448	0.9792787	8,273
6	Other Industry Dues	Technical/Professional	8,169	0.9792787	8,000
7	Total Industry Association Dues		665,617		651,824
8	Average Number of Customers		434,441		434,440
9	Dues Per Customer		1.53		1.50
10	Lobby Expenses Included in Industry Association Dues		0		0

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide the following information regarding the use of outside professional services during the test year. Segregate the services by types such as accounting, financial, engineering, legal or other. If a projected test period is used, provide on both a projected and a historical basis for services exceeding the greater of $1,000,000 or .5% (.005) of operation and maintenance expenses.

Type of Data Shown:
X Projected Test Year Ended 12/31/14
__ Prior Year Ended 12/31/13
X Historical Year Ended 12/31/12
Witness: C. J. Erickson

(1) Line No.	(2) Type of Service	(3) Description of Service(s)	(4) Accounts Charged	(5) Test Year Costs	(6) Historical Year Costs
1	Accounting			None over the threshold in any year	
2	Financial			None over the threshold in any year	
3	Engineering			None over the threshold in any year	
4	Legal			None over the threshold in any year	
5	Other (specify)			None over the threshold in any year	
6	Total Outside Professional Services				

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide the following information concerning pension cost for the test year and the most recent historical year if the test year is projected.

(000's)

Type of Data Shown:
X Projected Test Year Ended 12/31/14
Prior Year Ended 12/31/13
X Historical Year Ended 12/31/12
Witness: C. J. Erickson

(1) Line No.	(2) Description	(3) Test Year 12/31/14 *	(4) Historical Year 12/31/12
1	Service Cost	11,816	9,101
2	Interest Cost	18,345	17,199
3	Expected/Actual Return on Assets	(27,695)	(25,932)
4	Net Amortization and Deferral	7,912	3,913
5	Amortization of Prior Service Cost	1,131	1,262
6	Total Net Periodic Pension Cost	11,509	5,543
7	For the Year:		
8	Expected Return on Assets	27,695	25,932
9	Assumed Rate of Return on Plan Assets	8.20%	8.20%
10	Amortization of Transition Asset or Obligation	0	0
11	Percent of Pension Cost Capitalized	21.54%	18.04%
12	Pension Cost Recorded in Account 926	8,900	4,440
13	Minimum Required Contribution Per IRS	0 (Note 1)	0 (Note 1)
14	Maximum Allowable Contribution Per IRS	Note 6	Note 2
15	Actual Contribution Made to the Trust Fund	0	13,400
16	Actuarial Attribution Approach Used for Funding	unit credit cost method	unit credit cost method
17		per IRC § 430	per IRC § 430
18	Assumed Discount Rate for Computing Funding	5.86% (Note 4)	7.04% (Note 3)
19	Allocation Method Used to Assign Costs if the Utility Is Not the		
20	Sole Participant in the Plan. Attach the Relevant Procedures.	Note 5	Note 5

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide the following information concerning pension cost for the test year and the most recent historical year if the test year is projected.

(000's)

Type of Data Shown:
X Projected Test Year Ended 12/31/14
Prior Year Ended 12/31/13
X Historical Year Ended 12/31/12
Witness: C. J. Erickson

(1) Line No.	(2) Description	(3) Test Year 12/31/2014 *	(4) Historical Year 12/31/2012
1	At Year End:		
2	Accumulated Benefit Obligation	Note 6	371,147
3	Projected Benefit Obligation	451,949	413,501
4	Vested Benefit Obligation	Note 7	Note 7
5	Assumed Discount Rate (Settlement Rate)	4.27%	4.27%
6	Assumed Rate for Salary Increases	3.59%	3.59%
7	Fair Value of Plan Assets	375,771	350,260
8	Market Related Value of Assets	369,871	335,986
9	Balance in Working Capital (Note 8)	54,565	75,963

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10 * Projections

11 Note 1 No contributions were required for 2012 or are projected to be required for 2014 after application of Funding Balances per IRC § 430.

12 Note 2 Gulf Power is a co-sponsor in The Southern Company pension plan. If the maximum allowed contribution was allocated between the
13 co-sponsors based on actual 2012 plan contributions, Gulf's maximum contribution would be approximately $120 million in 2012.

14 Note 3 The 2012 Effective Interest Rate reflects yield curves mandated by IRC § 430.

15 Note 4 The projected 2014 Effective Interest Rate reflects projected yield curves mandated by IRC § 430.

16 Note 5 Gulf Power is a co-sponsor in The Southern Company pension plan; however, for accounting purposes, its pension benefit liabilities,
17 assets, and annual costs are calculated as if it sponsored its own plan.

18 Note 6 Projected amount not readily available.

19 Note 7 Amount is not required to be disclosed by GAAP and is not supplied with Gulf Power Co.'s actuarial information.

20 Note 8 Includes Account Numbers 128-00920, 128-00921, 182-30830, 182-30840, 228-30012, 228-30014, 228-30028, 228-30068,
21 228-33010, and 242-01020

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide a schedule, by organization, of any expenses for lobbying, civic, political, and related activities for civic/charitable contributions included for recovery in cost of service for the test year and the most recent historical year.

Type of Data Shown:
X Projected Test Year Ended 12/31/14
Prior Year Ended 12/31/13
X Historical Year Ended 12/31/12

Witness: C. J. Erickson

Line No.			
1	LOBBYING AND OTHER POLITICAL EXPENSES		
2		The Company has made the appropriate adjustments to remove lobbying	
3		and other political expenses when determining Net Operating Income.	
4	CIVIC / CHARITABLE CONTRIBUTIONS		
5		All charitable contributions are treated as "below the line" expenses.	
6		Civic expenses such as Chamber of Commerce dues are listed below:	
7			(000's)
8		Test Year	28
9		Historical Year	21

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Supporting Schedules:

Recap Schedules:

Schedule C-19 AMORTIZATION/RECOVERY SCHEDULE - 12-MONTHS Page 1 of 1

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide a schedule for each Amortization/Recovery amount by account or sub-account currently in effect or proposed and not shown on Schedule B-9.

($000's)

Type of Data Shown:
_X_ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
___ Historical Year Ended 12/31/12
Witness: S. D. Ritenour, C. J. Erickson

(1) Line No.	(2) Account/ Sub-account Number	(3) Plant Account Title	(4) Total Amort/Recovery Expense	(5) Effective Date	(6) Amortization/ Recovery Period	(7) Reason
1	411	Gains on Disposition of Emission Allowances	(172)	Various	Various	Gains from the disposition of emission allowances are amortized annually by the vintage year. These are recoverable through the environmental clause and are included in the environmental adjustments.
2	407	Amortization of Non-AMI Meters	886	4/1/2012	8 Years	Amortization of analog meters, as approved in Gulf's 2011 rate case, Docket No. 110138-EI, Order No. PSC-12-0179-F0F-EI, Issued April 3, 2012.
3	407	Amortization of Medicare Subsidy	327	4/1/2010	14 Years	The Patient Protection and Affordable Care Act and the Health Care and Education Reconciliation Act of 2010 eliminated the deductibility of healthcare costs that are covered by federal Medicare subsidy payments.

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide a schedule of taxes other than income taxes for the historical base year, historical base year + 1, and the test year. For each tax, indicate the amount charged to operating expenses. Complete columns 7, 8 and 9 for the historical base year and test year only.

Type of Data Shown:
X Projected Test Year Ended 12/31/14
_ Prior Year Ended 12/31/13
_ Historical Year Ended 12/31/12
Witness: C. J. Erickson

($000's)

(1) Line No.	(2) Type of Tax	(3) Rate	(4) Tax Basis $	(5) Total Amount	(6) Amount Charged to Operating Expense	(7) Jurisdictional Factor	(8) Jurisdictional Amount	(9) Jurisdictional Amount Charged to Operating Expenses
1	Federal Unemployment	0.008	Wages	91	91	0.9540263	87	87
2	State Unemployment	Various	Wages	149	149	0.9540263	142	142
3	FICA	0.0765	Wages	8,837	7,063	0.9540263	8,431	6,738
4	Federal Vehicle	Various	Various	7	0	0.9809524	7	0
5	State Intangible	NA	NA	0	0	0.9809524	0	0
6	Utility Assessment Fee	0.00072	1,362,573	981	981	1.0000000	981	981
7	Property	Various	Assessed Values	28,706	28,546	0.9425221	27,056	26,905
8	Gross Receipts	0.025	1,334,858	33,371	33,371	1.0000000	33,371	33,371
9	Franchise Fee	Various	Revenue	41,160	41,160	1.0000000	41,160	41,160
10	Occupational License	Various	Various	12	12	0.9809524	12	12
11	Other - Mississippi Franchise Tax	0.0025	122,659	307	307	0.9706840	298	298
12	Other - Florida Use Tax - Electricity	Various	Various	80	80	0.9809524	78	78
13	Other - Georgia Net Worth Tax	Various	Various	5	5	0.9809524	5	5
14	Other - Miscellaneous	Various	Various	8	8	0.9809524	8	8
15	Total			$ 113,714	$ 111,773		$ 111,636	$ 109,785

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide a schedule of taxes other than income taxes for the historical base year, historical base year + 1, and the test year. For each tax, indicate the amount charged to operating expenses. Complete columns 7, 8 and 9 for the historical base year and test year only.

Type of Data Shown:
_ Projected Test Year Ended 12/31/14
X Prior Year Ended 12/31/13
_ Historical Year Ended 12/31/12
Witness: C. J. Erickson

($000's)

(1) Line No.	(2) Type of Tax	(3) Rate	(4) Tax Basis $	(5) Total Amount	(6) Amount Charged to Operating Expense	(7) Jurisdictional Factor	(8) Jurisdictional Amount	(9) Jurisdictional Amount Charged to Operating Expenses
1	Federal Unemployment	0.008	Wages	91	91	0.9540263	87	87
2	State Unemployment	Various	Wages	149	149	0.9540263	142	142
3	FICA	0.0765	Wages	8,579	6,857	0.9540263	8,185	6,542
4	Federal Vehicle	Various	Various	7	0	0.9809524	7	0
5	State Intangible	NA	NA	0	0	0.9809524	0	0
6	Utility Assessment Fee	0.00072	1,301,317	937	937	1.0000000	937	937
7	Property	Various	Assessed Values	26,198	26,047	0.9425221	24,692	24,550
8	Gross Receipts	0.025	1,247,249	31,181	31,181	1.0000000	31,181	31,181
9	Franchise Fee	Various	Revenue	38,337	38,337	1.0000000	38,337	38,337
10	Occupational License	Various	Various	12	12	0.9809524	12	12
11	Other - Mississippi Franchise Tax	0.0025	113,569	284	284	0.9706840	276	276
12	Other - Florida Use Tax - Electricity	Various	Various	80	80	0.9809524	78	78
13	Other - Georgia Net Worth Tax	Various	Various	5	5	0.9809524	5	5
14	Other - Miscellaneous	Various	Various	8	8	0.9809524	8	8
15	Total			$ 105,868	$ 103,988		$ 103,947	$ 102,155

Schedule C-20 | TAXES OTHER THAN INCOME TAXES | Page 3 of 3

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide a schedule of taxes other than income taxes for the historical base year, historical base year + 1, and the test year. For each tax, indicate the amount charged to operating expenses. Complete columns 7, 8 and 9 for the historical base year and test year only.

Type of Data Shown:
_ Projected Test Year Ended 12/31/14
_ Prior Year Ended 12/31/13
X Historical Year Ended 12/31/12
Witness: C. J. Erickson

($000's)

(1) Line No.	(2) Type of Tax	(3) Rate	(4) Tax Basis $	(5) Total Amount	(6) Amount Charged to Operating Expense	(7) Jurisdictional Factor	(8) Jurisdictional Amount	(9) Jurisdictional Amount Charged to Operating Expenses
1	Federal Unemployment	0.006	Wages	88	87	0.9540263	84	83
2	State Unemployment	Various	Wages	253	252	0.9540263	241	240
3	FICA	0.0765	Wages	9,022	7,212	0.9540263	8,607	6,880
4	Federal Vehicle	Various	Various	18	0	0.9809524	18	0
5	State Intangible	NA	NA	0	0	0.9809524	0	0
6	Utility Assessment Fee	0.00072	1,208,808	870	870	1.0000000	870	870
7	Property	Various	Assessed Values	23,230	22,827	0.9425221	21,895	21,515
8	Gross Receipts	0.025	1,154,322	28,858	28,858	1.0000000	28,858	28,858
9	Franchise Fee	Various	Revenue	36,797	36,797	1.0000000	36,797	36,797
10	Occupational License	Various	Various	12	12	0.9809524	12	12
11	Other - Mississippi Franchise Tax	0.0025	82,000	205	205	0.9706840	199	199
12	Other - Florida Use Tax - Electricity	Various	Various	60	60	0.9809524	59	59
13	Other - Georgia Net Worth Tax	Max. Amount - $5,000	Various	5	5	0.9809524	5	5
14	Other - Florida Sales Taxes	Various	Various	501	128	0.9809524	491	126
15	Total			$ 99,919	$ 97,313		$ 98,136	$ 95,644

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Supporting Schedules:

Recap Schedules: C-1

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide a calculation of the Gross Receipts Tax and Regulatory Assessment Fee for the historical base year, historical base year + 1, and the test year.

Type of Data Shown:
X Projected Test Year Ended 12/31/14
X Prior Year Ended 12/31/13
X Historical Year Ended 12/31/12
Witness: C. J. Erickson

($000's)

(1) Line No.		(2)	(3)	(4)	(5)	(6)	(7)
		GROSS RECEIPTS TAX			REGULATORY ASSESSMENT FEE		
		2012	2013	2014	2012	2013	2014
1	TOTAL OPERATING REVENUES	$ 1,439,896	$ 1,507,740	$ 1,572,445	$ 1,439,896	$ 1,507,740	$ 1,572,445
2	ADJUSTMENTS:						
3	Less: Miscellaneous Service Revenues	4,422	4,731	4,789	0	0	0
4	Rent - Electric Property	6,898	6,227	6,331	0	0	0
5	O/U Recovery - Clauses	10,676	27,043	0	0	0	0
6	Other Operating Revenues	27,239	15,352	15,804	0	0	0
7	Provision for Rate Refunds	(1,242)	0	0	0	0	0
8	Non - Territorial Sales	200,324	176,580	176,794	200,324	176,580	176,794
9	Sales for Resale - Territorial	30,764	29,843	33,077	30,764	29,843	33,077
10	Unbilled Revenue	3,881	716	791	0	0	0
11	Bad Debts *	2,612	0	0	0	0	0
12	TOTAL ADJUSTMENTS	285,574	260,492	237,586	231,088	206,423	209,871
13	ADJUSTED OPERATING REVENUES	1,154,322	1,247,248	1,334,859	1,208,808	1,301,317	1,362,574
14	TAX RATE	0.025	0.025	0.025	0.00072	0.00072	0.00072
15	TAX AMOUNT	$ 28,858	$ 31,181	$ 33,371	$ 870	$ 937	$ 981

16 * In the forecast years, bad debt expense was not included in the calculation of gross receipts tax. There is no net effect on Net Operating Income.

Supporting Schedules: C-1, C-5

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

EXPLANATION: Provide the calculations of state and federal income taxes for the historical base year and the projected test year.

Type of Data Shown:
X Projected Test Year Ended 12/31/14
Prior Year Ended 12/31/13
Historical Year Ended 12/31/12

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

(000's)

Witness: C. J. Erickson

(1) Line No.	(2) DESCRIPTION	(3) CURRENT TAX STATE	(4) CURRENT TAX FEDERAL	(5) TOTAL	(6) DEFERRED TAX STATE	(7) DEFERRED TAX FEDERAL	(8) TOTAL
1	NET UTILITY OPERATING INCOME	$ 164,795	$ 164,795				
2	ADD INCOME TAX ACCOUNTS	65,944	65,944				
3	LESS INTEREST CHARGES (FROM C-23)	(58,557)	(58,557)				
4	TAXABLE INCOME PER BOOKS	172,182	172,182				
5	TEMPORARY ADJUSTMENTS TO TAXABLE INCOME (LIST)						
6	ADD: BOOK DEPRECIATION	149,469	149,469				
7	LESS: AFUDC Equity	(12,468)	(12,468)				
8	LESS: TAX DEPRECIATION	(305,748)	(207,202)				
9	Tax over book depreciation	(168,747)	(70,201)		8,609	16,884	
10	Employee Benefits	13,017	13,017		(716)	(4,305)	
11	Emission Allowances	669	669		(37)	(221)	
12	Deferred Revenues	(186)	(186)		10	62	
13	Bad Debt Reserve	119	119		(7)	(39)	
14	Injuries & Damages Reserve	195	195		(11)	(64)	
15	Property Damage Reserve	3,379	3,379		(186)	(1,118)	
16	Loss/Gain on Reacquired Debt	1,316	1,316		(72)	(435)	
17		18,509	18,509		(1,019)	(6,120)	
18	TOTAL TEMPORARY DIFFERENCES	(150,238)	(51,692)		7,590	10,764	

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide the calculations of state and federal income taxes for the historical base year and the projected test year.

Type of Data Shown:
X Projected Test Year Ended 12/31/14
Prior Year Ended 12/31/13
Historical Year Ended 12/31/12
Witness: C. J. Erickson

(000's)

(1) Line No.	(2) DESCRIPTION	(3) CURRENT TAX STATE	(4) CURRENT TAX FEDERAL	(5) TOTAL	(6) DEFERRED TAX STATE	(7) DEFERRED TAX FEDERAL	(8) TOTAL
1	PERMANENT ADJUSTMENTS TO TAXABLE INCOME (LIST)						
2	Non-deductible book depreciation	2,937	2,955				
3	AFUDC Equity	12,468	12,468				
4	Meals and Entertainment	337	337				
5	Medicare Subsidy	(235)	(235)				
6	Other	5	55				
7	TOTAL PERMANENT ADJUSTMENTS	15,512	15,580		0	0	
8	ADJUSTMENTS TO DEFERRED TAXES				0	0	
9	STATE TAXABLE INCOME	37,456			7,590	10,764	
10	STATE INCOME TAX (5.5% OR APPLICABLE RATE)						
11	Florida 5.5%; Mississippi 5.0%; Georgia 5.7%	2,060					
12	ADJUSTMENTS TO STATE INCOME TAX (LIST)						
13	State of Georgia Investment Tax Credit	(126)			0		
14	FIN 48 Reserve	0			0		
15	Return to Accrual Out of Period Adj	0			0		
16	TOTAL ADJUSTMENTS TO STATE INCOME TAX	(126)			0		
17	STATE INCOME TAX	1,934			7,590		
18	FEDERAL TAXABLE INCOME		136,070			10,764	
19	State Tax Deduction		(1,934)				
20			134,136				
21	FEDERAL INCOME TAX (35% OR APPLICABLE RATE)		46,948				

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

E PLANATION: Provide the calculations of state and federal income taxes for the historical base year and the projected test year.

Type of Data Shown:
X Projected Test Year Ended 12/31/14
____ Prior Year Ended 12/31/13
____ Historical Year Ended 12/31/12
Witness: C. J. Erickson

(000's)

(1) Line No.	(2) DESCRIPTION	(3) CURRENT TAX STATE	(4) CURRENT TAX FEDERAL	(5) CURRENT TAX TOTAL	(6) DEFERRED TAX STATE	(7) DEFERRED TAX FEDERAL	(8) DEFERRED TAX TOTAL
1	ADJUSTMENTS TO FEDERAL INCOME TAX						
2	ORIGINATING ITC						
3	WRITE OFF OF E CESS DEFERRED TAXES						
4	OTHER ADJUSTMENTS (LIST)						
5	R&D Credit		(113)			0	
6	FIN 48 Reserve		45			0	
7	Return to Accrual Out of Period Adj		0			0	
8	TOTAL ADJUSTMENTS TO FEDERAL INCOME TAX		(68)			0	
9	FEDERAL INCOME TAX		46,880			10,764	
10	ITC AMORTIZATION	0	(1,224)				

		FEDERAL	STATE	TOTAL
11	SUMMARY OF INCOME TAX E PENSE:			
12				
13	CURRENT TAX E PENSE	46,880	1,934	48,814
14	DEFERRED INCOME TA ES	10,764	7,590	18,354
15	INVESTMENT TAX CREDITS, NET	(1,224)	0	(1,224)
16	TOTAL INCOME TAX PROVISION	56,420	9,524	65,944

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

E PLANATION: Provide the calculations of state and federal income taxes for the historical base year and the projected test year.

Type of Data Shown:
____ Projected Test Year Ended 12/31/14
____ Prior Year Ended 12/31/13
_X_ Historical Year Ended 12/31/12
Witness: C. J. Erickson

(000's)

(1) Line No.	(2) DESCRIPTION	(3) CURRENT TAX STATE	(4) CURRENT TAX FEDERAL	(5) TOTAL	(6) DEFERRED TAX STATE	(7) DEFERRED TAX FEDERAL	(8) TOTAL
1	NET UTILITY OPERATING INCOME	$ 188,653	$ 188,653				
2	ADD INCOME TAX ACCOUNTS	78,190	78,190				
3	LESS INTEREST CHARGES (FROM C-23)	(60,250)	(60,250)				
4	TAXABLE INCOME PER BOOKS	206,593	206,593				
5	TEMPORARY ADJUSTMENTS TO TAXABLE INCOME (LIST)						
6	ADD: BOOK DEPRECIATION	134,778	134,778				
7	LESS: AFUDC Equity	(5,221)	(5,221)				
8	LESS: TAX DEPRECIATION	(318,785)	(558,385)				
9	Tax over book depreciation	(189,228)	(428,828)		10,140	144,253	
10	Purchased Power Capacity Recovery	(8,887)	(8,887)		490	3,026	
11	Employee Benefits	(3,411)	(3,411)		188	1,162	
12	Emission Allowances	1,268	1,268		(70)	(432)	
13	Energy Conservation Cost Recovery	2,323	2,323		(128)	(791)	
14	Environmental Cost Recovery	(11,847)	(11,847)		653	4,034	
15	Deferred Revenues	(154)	(154)		8	52	
16	Interest on Audits	400	400		(22)	(136)	
17	Bad Debt Reserve	(472)	(472)		26	161	
18	Fuel Cost Recovery	7,163	7,163		(395)	(2,439)	
19	Injuries & Damages Reserve	321	321		(18)	(109)	
20	Property Damage Reserve	1,483	1,483		(82)	(505)	
21	Loss/Gain on Reacquired Debt	(1,963)	(1,963)		108	668	
22	Other	(21)	(21)		1	7	
23		(13,797)	(13,797)		759	4,698	
24	TOTAL TEMPORARY DIFFERENCES	(203,025)	(442,625)		10,899	148,951	

Schedule C-22 | STATE AND FEDERAL INCOME TAX CALCULATION | Page 5 of 6

FLORIDA PUBLIC SERVICE COMMISSION

EXPLANATION: Provide the calculations of state and federal income taxes for the historical base year and the projected test year.

Type of Data Shown:
____ Projected Test Year Ended 12/31/14
____ Prior Year Ended 12/31/13
__X__ Historical Year Ended 12/31/12

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

(000's)

Witness: C. J. Erickson

(1) Line No.	(2) DESCRIPTION	(3) CURRENT TAX STATE	(4) CURRENT TAX FEDERAL	(5) TOTAL	(6) DEFERRED TAX STATE	(7) DEFERRED TAX FEDERAL	(8) TOTAL
1	PERMANENT ADJUSTMENTS TO TAXABLE INCOME (LIST)						
2	Non-deductible book depreciation	2,969	3,051				
3	AFUDC Equity	5,221	5,221				
4	Meals and Entertainment	318	318				
5	Medicare Subsidy	(532)	(532)				
6	Other	35	60				
7	TOTAL PERMANENT ADJUSTMENTS	8,011	8,118		0	0	
8	ADJUSTMENTS TO DEFERRED TAXES				0	0	
9	STATE TAXABLE INCOME	11,579			10,899	148,951	
10	STATE INCOME TAX (5.5% OR APPLICABLE RATE)						
11	Florida 5.5%; Mississippi 5.0%; Georgia 5.7%	639					
12	ADJUSTMENTS TO STATE INCOME TAX (LIST)						
13	State of Georgia Investment Tax Credit	(283)			0		
14	FIN 48 Reserve	(94)			(501)		
15	Return to Accrual Out of Period Adj	(2,701)			2,814		
16	TOTAL ADJUSTMENTS TO STATE INCOME TAX	(3,078)			2,313		
17	STATE INCOME TAX	(2,439)			13,212		
18	FEDERAL TAXABLE INCOME		(227,914)			148,951	
19	State Tax Deduction		(357)				
20			(228,271)				
21	FEDERAL INCOME TAX (35% OR APPLICABLE RATE)		(79,896)				

Supporting Schedules: C-23

Recap Schedules: C-1

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide the calculations of state and federal income taxes for the historical base year and the projected test year.

(000's)

Type of Data Shown:
____ Projected Test Year Ended 12/31/14
____ Prior Year Ended 12/31/13
X Historical Year Ended 12/31/12
Witness: C. J. Erickson

(1) Line No.	(2) DESCRIPTION	(3) CURRENT TAX STATE	(4) CURRENT TAX FEDERAL	(5) CURRENT TAX TOTAL	(6) DEFERRED TAX STATE	(7) DEFERRED TAX FEDERAL	(8) DEFERRED TAX TOTAL
1	ADJUSTMENTS TO FEDERAL INCOME TAX						
2	ORIGINATING ITC						
3	WRITE OFF OF EXCESS DEFERRED TAXES						
4	OTHER ADJUSTMENTS (LIST)						
5	R&D Credit		(112)			0	
6	FIN 48 Reserve		2,210			(3,202)	
7	Return to Accrual Out of Period Adj		(14,543)			15,361	
8	TOTAL ADJUSTMENTS TO FEDERAL INCOME TAX		(12,445)			12,159	
9	FEDERAL INCOME TAX		(92,341)			161,110	
10	ITC AMORTIZATION	0	(1,352)				

		FEDERAL	STATE	TOTAL
11	SUMMARY OF INCOME TAX EXPENSE:			
12	CURRENT TAX EXPENSE	(92,341)	(2,439)	(94,780)
13	DEFERRED INCOME TAXES	161,110	13,212	174,322
14	INVESTMENT TAX CREDITS, NET	(1,352)	0	(1,352)
15	TOTAL INCOME TAX PROVISION	67,417	10,773	78,190

Schedule C-23	INTEREST IN TAX EXPENSE CALCULATION	Page 1 of 1
FLORIDA PUBLIC SERVICE COMMISSION	EXPLANATION: Provide the amount of interest expense used to calculate net operating income taxes on Schedule C-22. If the basis for allocating interest used in the tax calculation differs from the basis used in allocating current income tax expense, the differing bases should be clearly identified.	Type of Data Shown:
COMPANY: GULF POWER COMPANY		X Projected Test Year Ended 12/31/14
		_ Prior Year Ended 12/31/13
DOCKET NO.: 130140-EI		X Historical Year Ended 12/31/12
		Witness: S. D. Ritenour

($000's)

(1) Line No.	(2) Description	(3) Historical Base Year Ended 12/31/12	(4) Test Year Ended 12/31/14
1	Interest on Long Term Debt	$57,942	$61,542
2	Amortization of Debt Discount, Premium, Issuing	2,602	2,400
3	Expense & Loss on Reacquired Debt		
4	Interest on Short Term Debt	272	416
5	Interest on Customer Deposits	1,702	814
6	Other Interest Expense	232	0
7	Less Allowance for Funds Used During Construction	(2,500)	(6,615)
8	Total Interest Expense	$60,250	$58,557

02

Supporting Schedules:

Recap Schedules: C-22

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide information required in order to adjust income tax expenses by reason of interest expense of parent(s) that may be invested in the equity of the utility in question. If a projected test period is used, provide on both a projected and historical basis.

Type of Data Shown:
X Projected Test Year Ended 12/31/14
Prior Year Ended 12/31/13
Historical Year Ended 12/31/12
Witness: R. S. Teel

(1) Line No.	(2) Description	(3) Amount (000's)	(4) Percent of Capital	(5) Cost Rate	(6) Weighted Cost
1	Long-Term Debt	1,534,000	13.83%	2.89%	0.40%
2	Short-Term Debt	320,000	2.89%	2.66%	0.08%
3	Preferred Stock	0	0.00%		0.0%
4	Common Equity*	9,236,756	83.28%		0.0%
5	Deferred Income Tax	0	0.00%		0.0%
6	Investment Tax Credits	0	0.00%		0.0%
7	Other (specify)	0	0.00%		0.0%
8	Total	$ 11,090,756	100.00%		0.48%
9	Weighted cost of parent debt 0.48% x Gulf combined tax rate 38.575% x equity* of subsidiary $1,105,912,000			=	$ 2,048,000

10 * Excluding retained earnings

11 As discussed in Witness Teel's testimony, a parent debt adjustment is not appropriate.

12

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide information required in order to adjust Income tax expenses by reason of interest expense of parent(s) that may be invested in the equity of the utility in question. If a projected test period is used, provide on both a projected and historical basis.

Type of Data Shown:
____ Projected Test Year Ended 12/31/14
____ Prior Year Ended 12/31/13
X Historical Year Ended 12/31/12
Witness: R. S. Teel

(1) Line No.	(2) Description	(3) Amount (000's)	(4) Percent of Capital	(5) Cost Rate	(6) Weighted Cost
1	Long Term Debt	1,510,000	14.29%	1.89%	0.27%
2	Short Term Debt	290,000	2.74%	0.17%	0.00%
3	Preferred Stock	0	0.00%		0.0%
4	Common Equity*	8,768,030	82.97%		0.0%
5	Deferred Income Tax	0	0.00%		0.0%
6	Investment Tax Credits	0	0.00%		0.0%
7	Other (specify)	0	0.00%		0.0%
8	Total	$ 10,568,030	100.00%		0.27%
9	Weighted cost of parent debt 0.27% x Gulf combined tax rate 38.575% x equity* of subsidiary $935,360,000			=	$ 974,000

10 * Excluding retained earnings

11 As discussed in Witness Teel's testimony, a parent debt adjustment is not appropriate.

Supporting Schedules:

Recap Schedules:

Schedule C-25 | DEFERRED TAX ADJUSTMENT | Page 1 of 1

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: To provide information required to present the excess/deficient deferred tax balances due to protected and unprotected timing differences at statutory tax rates different from the current tax rate. The protected deferred tax balances represent timing differences due to Life and Method effect on depreciation rates.

Type of Data Shown:
X Projected Test Year Ended 12/31/14
X Prior Year Ended 12/31/13
X Historical Year Ended 12/31/12
Witness: C. J. Erickson

(1) Line No.	(2) Balance and Activity	(3) Taxes Protected	(4) Taxes Unprotected	(5) Total Excess/(Deficient)
1	Balance at Beginning of Historical Year	1,447,674	2,923,126	4,370,800
2	Historical Year Amortization	(381,561)	(350,011)	(731,572)
3	Balance at Beginning of Historical Year + 1	1,066,113	2,573,115	3,639,228
4	Historical Year + 1 Amortization	(494,739)	(240,346)	(735,085)
5	Balance at Beginning of Projected Test Year	571,374	2,332,769	2,904,143
6	Projected Test Year Amortization	(218,776)	(231,372)	(450,148)
7	Balance at End of Projected Test Year	352,598	2,101,397	2,453,995

Supporting Schedules:

Recap Schedules:

Schedule C-26	INCOME TAX RETURNS	Page 1 of 1
FLORIDA PUBLIC SERVICE COMMISSION	EXPLANATION: Provide a copy of the company's most recent consolidated Federal Income Tax Return,	Type of Data Shown:
		___Projected Test Year Ended 12/31/14
COMPANY: GULF POWER COMPANY	State Income Tax Return and most recent final IRS	___Prior Year Ended 12/31/13
	revenue agent's report.	_X_ Historical Year Ended 12/31/12
DOCKET NO.: 130140-EI		Witness: C. J. Erickson

Line No.	
1	Gulf's portion of the Consolidated Federal Income Tax Return and Gulf's section
2	of the most recent final IRS revenue agent's report along with the State Income
3	Tax Return will be made available for review at the Company's Corporate Office
4	located at 500 Bayfront Parkway, Pensacola, FL 32501.
5	The remaining portions of the Consolidated Return and the IRS agent's
6	report are located at 241 Ralph McGill Blvd., Atlanta, GA 30308-3374.

Supporting Schedules:

Recap Schedules:

Schedule C-27	CONSOLIDATED TAX INFORMATION	Page 1 of 1
FLORIDA PUBLIC SERVICE COMMISSION	EXPLANATION: Provide a summary of the specific tax effects (in dollars) of filing a consolidated return for the test year. Identify the nature and amount of benefits to the company and to the ratepayers.	Type of Data Shown:
COMPANY: GULF POWER COMPANY		X Projected Test Year Ended 12/31/14
		___ Prior Year Ended 12/31/13
		___ Historical Year Ended 12/31/12
DOCKET NO.: 130140-EI		Witness: C. J. Erickson

Line No.

For the Southern system, the only tax effect that occurs from the filing of a consolidated Federal Income Tax Return relates to the allocation of Southern Company's Tax loss on taxable income to the members of the consolidated group. Gulf Power records its portion of the tax loss from Southern Company as a capital contribution. The reduction in income tax expense is recorded at The Southern Company.

The Southern Company's consolidated tax reduction should not be treated as a reduction in Gulf Power Company's tax expense for ratemaking purposes because the related expenses creating the benefit have not been included in expenses for ratemaking purposes.

The tax loss of The Southern Company results from the deductions of various corporate expenses of The Southern Company such as Annual Report costs, director's fees and expenses, stockholders' meeting expenses, transfer agents and dividend paying agent's fees and expenses, legal fees and interest expenses. These expenses of The Southern Company are not paid by Gulf Power Company, its ratepayers or any other company included in this affiliated group. These expenses are borne solely by the stockholders of The Southern Company rather than the ratepayers of Gulf Power Company.

If The Southern Company were to allocate its expenses to the operating companies, and if these expenses were included in the computation of Gulf's net operating income for ratemaking purposes, then, and only then, would it be appropriate for the related tax reduction to be included as an adjustment and "passed on."

The requested information will be made available for your review at the Company's General Office located at 500 Bayfront Parkway, Pensacola, FL 32501.

Supporting Schedules:

Recap Schedules:

Schedule C-28 | MISCELLANEOUS TAX INFORMATION | Page 1 of 1

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide the requested miscellaneous tax information.

Type of Data Shown:
___ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
_X_ Historical Year Ended 12/31/12
Witness: C. J. Erickson

Line No.	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	1. For profit and loss purposes, which IRC section 1552						
2	method is used for tax allocation?		1552(a)(1)				
3	2. What tax years are open with the IRS?		2009, 2010, 2012 and forward				
4	3. For the last three tax years, what dollars were paid to or						
5	received from the parent for federal income taxes?						
6			2010	2011	2012		
7	Federal Income Tax Paid (Received)		$7,239,994	($25,349,365)	($92,024,678)		
8	4. How were the amounts in (3) treated?		Estimated payments were remitted to The Southen Company (parent)				
9			who remitted the consolidated payment to the IRS.				
10	5. For each of the last three years, what was the dollar amount of		Southern Company files a consolidated tax return and does not have a parent only tax return.				
11	interest deducted on the parent ONLY tax return?						
12	6. Complete the following chart for the last three years:						

13		Income (loss)					
14		Book Basis[a]			Tax Basis		
15		Year			Year		
16		2010	2011	2012	2010	2011	2012[b]
17	Parent Only	($41,763,132)	($39,272,397)	$5,534,454	($234,542,287)	($222,112,429)	($192,080,871)
18	Applicant Only	$121,510,993	$105,004,967	$125,931,984	($10,510,622)	($98,620,125)	($180,467,847)
19	Total Group	$1,975,472,208	$2,202,555,996	$2,350,042,796	$307,299,541	$300,084,168	$561,198,369
20	Total Group Excluding	$1,895,724,347	$2,136,823,426	$2,218,576,358	$552,352,450	$620,816,722	$933,747,087
21	Parent & Applicant						

22 (a) Net Income After Dividends on Preferred and Preference Stock
23 (b) Estimated tax basis for year 2012

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide a schedule of gains and losses on disposition of plant and property previously used in providing electric service for the test year and the four prior years. List each item with a gain or loss of $1 million or more, or more than .1% of total plant. List amounts allowed in prior cases, and the test year of such prior cases.

Type of Data Shown:
X Projected Test Year Ended 12/31/14
X Prior Year Ended 12/31/13
X Historical Year Ended 12/31/10-12/31/12
Witness: C. J. Erickson, S. D. Ritenour

($000's)

(1) Line No	(2) Description of Property	(3) Date Acquired	(4) Date Disposed	(5) Original Classification Account	(6) Reclass-ification Account(s)	(7) Reclass-ification Date(s)	(8) Original Amount Recorded	(9) Additions or (Retirements)	(10) Depreciation and Amortization	(11) Net Book Value on Disposal Date	(12) Gain or (Loss)	(13) Amounts Allowed Prior Cases	(14) Prior Cases Test Year Ended 12/31/14
1			2014	No gains or losses, in excess of $1 million, on dispositions of property are forecasted.								N/A	N/A
2			2013	No gains or losses, in excess of $1 million, on dispositions of property are forecasted.								N/A	N/A
3			2012	No gains or losses, in excess of $1 million, on dispositions of property.								N/A	N/A
4			2011	No gains or losses, in excess of $1 million, on dispositions of property.								N/A	N/A
5			2010	No gains or losses, in excess of $1 million, on dispositions of property.								N/A	N/A

Supporting Schedules:

Recap Schedules:

Schedule C-30 | TRANSACTIONS WITH AFFILIATED COMPANIES | Page 1 of 1

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide a schedule detailing transactions with affiliated companies and related parties for the test year including intercompany charges, licenses, contracts and fees.

Type of Data Shown:
__X__ Projected Test Year Ended 12/31/14
_____ Prior Year Ended 12/31/13
_____ Historical Year Ended 12/31/12
Witness: R. J. McMillan, C. J. Erickson

Line No.	(1) Name of Company Or Related Party	(2) Relation to Utility	(3) Type of Service Provided or Received	(4) Effective Contract Date	(5) Charge or Credit During Year $000	(6) Account	(7) Amount Included in Test Year $000	(8) Allocation Method Used to Allocate Charges Between Companies
1	Alabama Power Company	Associated Company	Transmission Facility Services	Various	12,239	567	12,239	Cost
2	Georgia Power Company	Associated Company	Plant Scherer Unit 3	03/01/84	11,960	Various	11,960	Per Contract
3			Transmission Facility Services	05/12/09	982	567	982	Cost
4					12,942		12,942	
5	Mississippi Power Company	Associated Company	Plant Daniel	06/01/81	22,211	Various	22,211	Cost
6			Transmission Facility Services	04/20/81	164	567	164	Cost
7					22,376		22,376	
8	Southern Company Services	Service Company	Service Agreement	01/01/84	61,564	Various	61,564	Cost
9			Interchange - Purchases	05/01/07	24,657	Various	24,657	Cost
10			Interchange - Sales	05/01/07	(80,361)	Various	(80,361)	Cost
11			Unit Power Sales	Various	(93,160)	Various	(93,160)	Cost
12					(87,299)		(87,299)	
13	Southern Company	Parent Company	Common Stock Dividends	n/a	120,560	238	120,560	Earnings
14			Capital Contributions	n/a	(120,798)	211	(120,798)	n/a
15					(238)		(238)	
16	Southern Power	Associated Company	Purchased Power Agreement	10/19/06	2,313	Various	2,313	Per Contract
17			TOTAL Transactions with Affiliated Companies		(37,668)		(37,668)	

18 Note: The amounts shown above are the significant amounts included in Gulf's financial forecast that could be specifically identified as transactions to be made with an
19 affiliate. The affiliated transactions shown are not all-inclusive. Gulf's budgeting process does not include the identification of specific vendors (affiliated or non-
20 affiliated) that will be utilized in company transactions.

21 Totals may not add due to rounding.

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide a copy of the diversification report included in the company's most recently filed Annual Report as required by Rule 25-6.135, Florida Administrative Code. Provide any subsequent changes affecting the test year.

Type of Data Shown:

___ Projected Test Year Ended 12/31/14

___ Prior Year Ended 12/31/13

_X_ Historical Year Ended 12/31/12

Witness: C. J. Erickson

Line No.	
1	See Attachment - Gulf Power Company's most recently filed Diversification Report.

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Supporting Schedules:

Recap Schedules:

Affiliation of Officers and Directors

Company: Gulf Power Company

For the Year Ended December 31, 2012

For each of the officials named in Part 1 of the Executive Summary, list the principal occupation or business affiliation if other than listed in Part 1 of the Executive Summary and all affiliations or connections with any other business or financial organizations, firms, or partnerships. For purposes of this part, the official will be considered to have an affiliation with any business or financial organization, firm or partnership in which he is an officer, director, trustee, partner, or a person exercising similar functions.

Name	Principal Occupation or Business Affiliation	Affiliation or Connection with any Other Business or Financial Organization Firm or Partnership	
		Affiliation or Connection	Name and Address
Officers:			
P. Bernard Jacob		Director	Baptist Health Care Pensacola, Florida
Michael L. Burroughs		Director	Sacred Heart Health System Pensacola, Florida
R. Scott Teel		Director	Sacred Heart Hospital of Pensacola Pensacola, Florida
		Director	Sacred Heart Health System Pensacola, Florida
		Director	American Red Cross Pensacola, Florida
		Director	Bill Bond Baseball League Pensacola, Florida
Bentina C. Terry		Director	SunTrust Pensacola, Florida (Ended March 2012)
Directors:			
Allan G. Bense	Chairman/CEO	Chairman/CEO	Bense Enterprises, Inc. Panama City, Florida
		Director	Bense Family Foundation, Inc. Panama City, Florida
		Director	Roussos Refrigeration, Heating, & Air Conditioning, Inc. Panama City, Florida
		Director	Bense Farms, Inc. Panama City, Florida
		Director	Brown Insurance Services LLC Panama City, Florida
		Director	Bay West Developers, Inc. Panama City, Florida
		Director	Gulf Coast Medical Center Panama City, Florida
		Officer	GAC Contractors, Inc. Panama City, Florida
		Officer	TDW, Inc. Panama City, Florida
		President & CEO	Holiday Golf & Racquet Club Panama City, Florida

Affiliation of Officers and Directors

Company: Gulf Power Company
For the Year Ended December 31, 2012

For each of the officials named in Part 1 of the Executive Summary, list the principal occupation or business affiliation if other than listed in Part 1 of the Executive Summary and all affiliations or connections with any other business or financial organizations, firms, or partnerships. For purposes of this part, the official will be considered to have an affiliation with any business or financial organization, firm or partnership in which he is an officer, director, trustee, partner, or a person exercising similar functions.

Name	Principal Occupation or Business Affiliation	Affiliation or Connection with any Other Business or Financial Organization Firm or Partnership	
		Affiliation or Connection	Name and Address
Berse (continued)		Director	Florida Council of 100 Panama City, Florida
		Chairman/Director	Florida State University Tallahassee, Florida
Deborah H. Calder	Sr. Vice President	Sr. Vice President	Navy Federal Credit Union Pensacola, Florida
		Director	Sacred Heart Health System Pensacola, Florida
William C. Cramer, Jr.	Automobile Dealer	President/ Owner	Bill Cramer Chevrolet Cadillac Buick GMC, Inc. Panama City, Florida
		President/ Owner	Bill Cramer Motors, Inc Donalsonville, Georgia
		President/ Owner	Outlet Rental Car Sales of Dothan, Inc. Dothan, Alabama
		President/ Owner	Cramer Properties, Inc Panama City, Florida
		President/ Owner	Cramer Properties of Alabama, Inc. Dothan, Alabama
		President/ Owner	Cramer Investments, Inc. Panama City, Florida
		President/ Partner	Cramer Investments, LLC Panama City, Florida
		President/ Partner	Cramer Brothers Investments, LLC Dothan, Alabama
		Director	Ceres Technologies, Inc. Panama City, Florida
		Trustee	The Cramer Family Limited Partnership Panama City, Florida
		President & Partner	Outlet Enterprises, LLC Enterprise, Alabama

Affiliation of Officers and Directors

Company: Gulf Power Company
For the Year Ended December 31, 2012

For each of the officials named in Part 1 of the Executive Summary, list the principal occupation or business affiliation if other than listed in Part 1 of the Executive Summary and all affiliations or connections with any other business or financial organizations, firms, or partnerships. For purposes of this part, the official will be considered to have an affiliation with any business or financial organization, firm or partnership in which he is an officer, director, trustee, partner, or a person exercising similar functions.

Name	Principal Occupation or Business Affiliation	Affiliation or Connection with any Other Business or Financial Organization Firm or Partnership	
		Affiliation or Connection	Name and Address
J. Mort O'Sullivan, III	Member	Member	Warren Averett, LLC (d/b/a Warren Averett O'Sullivan Creel) Pensacola, Florida
		Board Member	Hancock Bank Pensacola, Florida
		Director	KaMedData Inc. Pensacola, Florida
		Director	Arca Tech Systems LLC Mebane, North Carolina
		Board Member	Landrum Companies Pensacola, Florida
		Director	Bio Fuel Investors LLC Pensacola, Florida
William A. Pullum	Realtor/Developer	President/Director	Bill Pullum Realty, Inc. Navarre, Florida
		President/ Director	Belleville Properties, Inc. Navarre, Florida
		Trustee	Betty J. Pullum Irrevocable Insurance Trust Navarre, Florida
		President/ Director	Bill & Martha Pullum Family Foundation, Inc. Navarre, Florida
		President/ Director	BPP, Inc. Navarre, Florida
		Sole Member	BPP, LLC Navarre, Florida

Affiliation of Officers and Directors

Company: Gulf Power Company
For the Year Ended December 31, 2012

For each of the officials named in Part 1 of the Executive Summary, list the principal occupation or business affiliation if other than listed in Part 1 of the Executive Summary and all affiliations or connections with any other business or financial organizations, firms, or partnerships. For purposes of this part, the official will be considered to have an affiliation with any business or financial organization, firm or partnership in which he is an officer, director, trustee, partner, or a person exercising similar functions.

Name	Principal Occupation or Business Affiliation	Affiliation or Connection with any Other Business or Financial Organization Firm or Partnership	
		Affiliation or Connection	Name and Address
Pullum (continued)		President/ Director	Bridgewater Properties, Inc. Pensacola, Florida
		Partner	Centurion Properties Pensacola, Florida
		Managing Member	CHH Enterprise, LLC. Pensacola, Florida
		President/ Director	Cowboy's Steakhouse, Inc. Navarre, Florida
		President/ Director	Crescent Shores Properties, Inc. Navarre, Florida
		Trustee	E. H. Pullum Trust Navarre, Florida
		Partner	Gentry Farms Navarre, Florida
		President/ Director	Helicopters of Northwest Florida, Inc. Navarre, Florida
		Sole Member	Navarre Ventures, LLC Navarre, Florida
		President/ Director	Northwood Properties, Inc. Pensacola, Florida
		President/ Director	Our Town Properties, Inc. Navarre, Florida

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Affiliation of Officers and Directors

Company: Gulf Power Company
For the Year Ended December 31, 2012

For each of the officials named in Part 1 of the Executive Summary, list the principal occupation or business affiliation if other than listed in Part 1 of the Executive Summary and all affiliations or connections with any other business or financial organizations, firms, or partnerships. For purposes of this part, the official will be considered to have an affiliation with any business or financial organization, firm or partnership in which he is an officer, director, trustee, partner, or a person exercising similar functions.

Name	Principal Occupation or Business Affiliation	Affiliation or Connection with any Other Business or Financial Organization Firm or Partnership	
		Affiliation or Connection	Name and Address
Pullum (continued)		Manager/Member	OTP, LLC Navarre, Florida
		President/ Director	Paco Properties, Inc. Navarre, Florida
		President/ Director	Persimmon Properties, Inc. Navarre, Florida
		Trustee	Pullum Family Irrevocable Insurance Trust Navarre, Florida
		President/ Director	Pullum Properties, Inc. Navarre, Florida
		President/ Director	Rotary Properties, Inc. Navarre, Florida
		Director	Santa Rosa Properties, Inc. Selma, Alabama
		Sole Member	Snowsnake Aviation, LLC Navarre, Florida
		Director	The Animal Park, Inc. Gulf Breeze, Florida
		Partner	Turkey Creek Developers Pensacola, Florida
		Sole Member	White Oak Timber, LLC Navarre, Florida
		President/ Director	White Oak Properties, Inc. Navarre, Florida
		President	Navarre 33, Inc. Navarre, Florida
		Member	Emerald Coast Gents Navarre, Florida
		Managing Member	Pullum Commerce Park, LLC Navarre, Florida

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Affiliation of Officers and Directors

Company: Gulf Power Company
For the Year Ended December 31, 2012

For each of the officials named in Part 1 of the Executive Summary, list the principal occupation or business affiliation if other than listed in Part 1 of the Executive Summary and all affiliations or connections with any other business or financial organizations, firms, or partnerships. For purposes of this part, the official will be considered to have an affiliation with any business or financial organization, firm or partnership in which he is an officer, director, trustee, partner, or a person exercising similar functions.

Name	Principal Occupation or Business Affiliation	Affiliation or Connection with any Other Business or Financial Organization Firm or Partnership	
		Affiliation or Connection	Name and Address
Pullum (continued)		Member	Vic's of Navarre, LLC Navarre, Florida
		Board Member	Hancock National Bank Navarre, Florida
		Member	Yellow River Ranch Pensacola, Florida
		Director	YMCA Navarre Navarre, Florida
Winston E. Scott	Senior Vice President for External Relations Florida Institute of Technology	Director	Environmental Tectonics Corporation Southampton, Pennsylvania

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Business Contracts with Officers, Directors and Affiliates

Company: Gulf Power Company

For the Year Ended December 31, 2012

List all contracts, agreements, or other business arrangements* entered into during the calendar year (other than compensation-related to position with respondent) between the respondent and each officer and director listed in Part 1 of the Executive Summary. In addition, provide the same information with respect to professional services for each firm, partnership, or organization with which the officer or director is affiliated.

Note * Business agreement, for this schedule, shall mean any oral or written business deal which binds the concerned parties for products or services during the reporting year or future years.

Name of Officer or Director	Name and Address of Affiliated Entity	Amount	Identification of Product or Service
J. Mort O'Sullivan, III	Warren Averett O'Sullivan Creel 316 S. Baylen St., Suite 300 Pensacola, FL 32502	1,000.00	Accounting Services
William Cramer	Bill Cramer Chevrolet Cadillac Buick GMC, Inc. 2251 West 23rd Street Panama City, Florida 32405	203.90	Car Leasing
William Cramer	Bill Cramer Chevrolet Cadillac Buick GMC, Inc. 2251 West 23rd Street Panama City, Florida 32405	2,058.74	Car Leasing

Reconciliation of Gross Operating Revenues
Annual Report versus Regulatory Assessment Fee Return

Company: Gulf Power Company *For the Year Ended December 31, 2012*

For the current year, reconcile the gross operating revenues as reported on Page 300 of this report with the gross operating revenues as reported on the utility's regulatory assessment fee return. Explain and justify any differences between the reported gross operating revenues in column (h).

Line No.	(a) Description	(b) Gross Operating Revenues per Page 300	(c) Interstate and Sales for Resale Adjustments	(d) Adjusted Intrastate Gross Operating Revenues	(e) Gross Operating Revenues per RAF Return	(f) Interstate and Sales for Resale Adjustments	(g) Adjusted Intrastate Gross Operating Revenues	(h) Difference (d) - (g)
1	Total Sales to Ultimate Customers (440-446, 448)	$1,133,224,178.20	$0.00	$1,133,224,178.20	$1,133,224,178.20	$0.00	$1,133,224,178.20	$0.00
2	Sales for Resale (447)	231,087,568.89	200,323,653.53	30,763,915.36	231,087,568.89	200,323,653.53	30,763,915.36	
3	Total Sales of Electricity	1,364,311,747.09	200,323,653.53	1,163,988,093.56	1,364,311,747.09	200,323,653.53	1,163,988,093.56	
4	Provision for Rate Refunds (449.1)	1,241,708.57		1,241,708.57	1,241,708.57		1,241,708.57	
5	Total Net Sales of Electricity	1,363,070,038.52	200,323,653.53	1,162,746,384.99	1,363,070,038.52	200,323,653.53	1,162,746,384.99	
6	Total Other Operating Revenues (450-456)	76,825,515.28		76,825,515.28	76,825,515.28	0.00	76,825,515.28	0.00
7	Other (Specify)							
8								
9								
10	Total Gross Operating Revenues	$1,439,895,553.80	$200,323,653.53	$1,239,571,900.27	$1,439,895,553.80	$200,323,653.53	$1,239,571,900.27	0.00

Notes:

Analysis of Diversification Activity
Changes in Corporate Structure

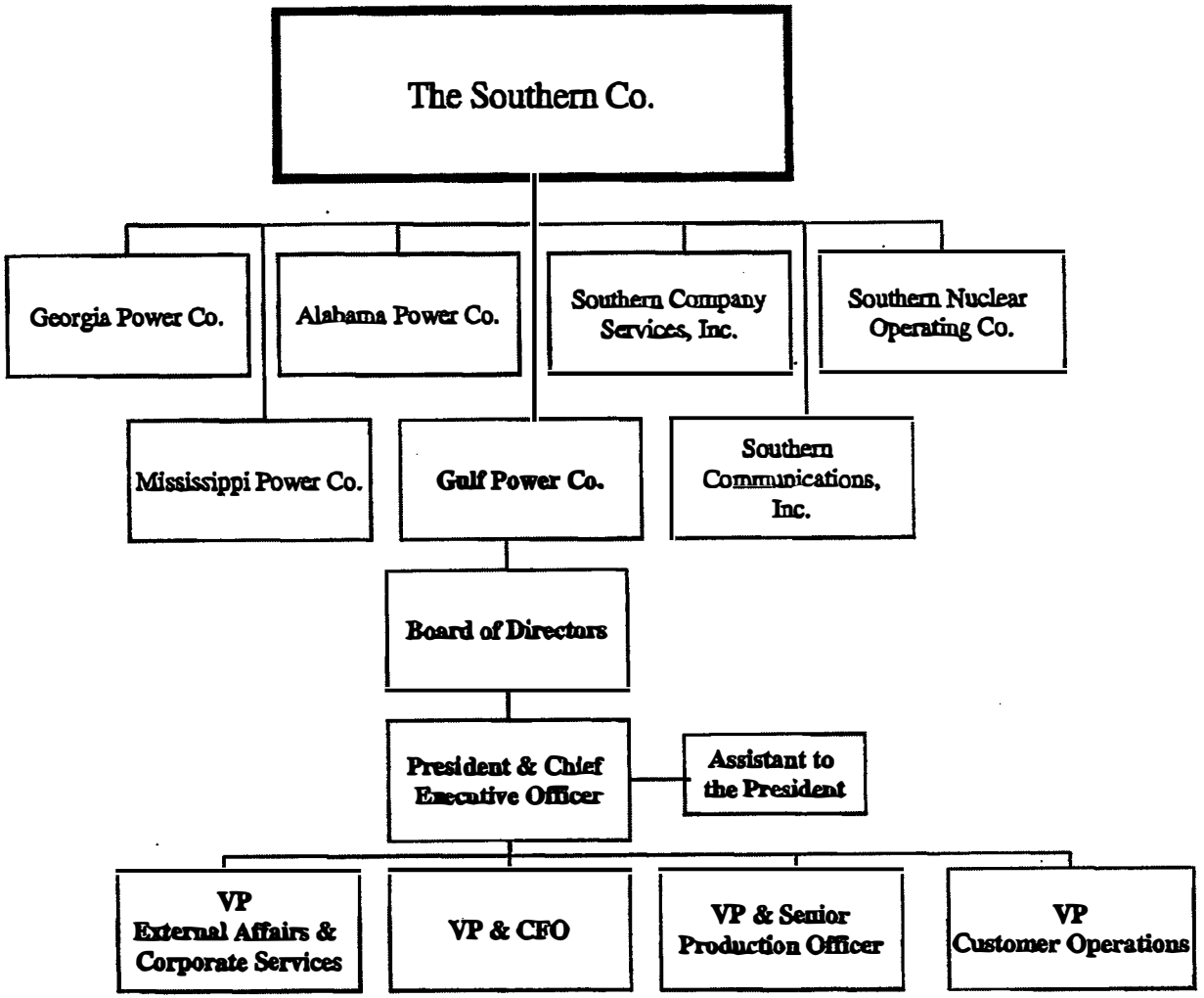
Company: Gulf Power Company

For the Year Ended December 31, 2012

Provide any changes in corporate structure including partnerships, minority interest, and joint ventures and an updated organizational chart, including all affiliates.

Effective Date (a)	Description of Change (b)
	No changes happened to the corporate structure in 2012.

The Southern Company
Parent & Affiliates
December, 2012



Analysis of Diversification Activity
New or Amended Contracts with Affiliated Companies

Company: Gulf Power Company
For the Year Ended December 31, 2012

Provide a synopsis of each new or amended contract, agreement, or arrangement with affiliated companies for the purchase, lease, or sale of land, goods, or services (excluding tariffed items). The synopsis shall include, at a minimum, the terms, price, quantity, amount, and duration of the contracts.

Name of Affiliated Company (a)	Synopsis of Contract (b)
Alabama Power Company	On July 1, 2012, Gulf Power Company signed a service agreement to reimburse the transmission investment costs associated with specific infrastructure improvements that are required to facilitate a Purchase Power Agreement (PPA) which Gulf Power previously entered into. The total cost of reimbursement is $59,112,046.08 and will be remitted through monthly payments which began August 1, 2012 and will terminate June 1, 2023.
Southern Linc	On April 4, 2012, Gulf Power Company signed Amendment Number One to the Master Facilities Coordination Agreement with Southern Communication Services, INC., D/B/A Southern Wireless. It added an additional tower site, Callaway. On April 10, 2012, Gulf Power Company signed Amendment Number Two to the Master Facilities Coordination Agreement with Southern Communication Services, INC., D/B/A Southern Wireless. It added an additional tower site, Ponce de Leon.

Analysis of Diversification Activity

Individual Affiliated Transactions in Excess of $500,000

Company: Gulf Power Company

For the Year Ended December 31, 2012

Provide information regarding individual affiliated transactions in excess of $500,000. Recurring monthly affiliated transactions which exceed $500,000 per month should be reported annually in the aggregate. However, each land or property sales transaction even though similar sales recur, should be reported as a "non-recurring" item for the period in which it occurs.

Name of Affiliate (a)	Description of Transaction (b)	Dollar Amount (c)
Georgia Power Company	Plant Scherer Unit No. 3 - Capital Cost, Fuel Purchases, O&M Expenses and Labor Benefits and Taxes	49,188,907
Mississippi Power Company	Plant Daniel - Capital Cost, Fuel Purchases, O&M Expenses, and Labor Benefits and Taxes	119,381,294
Southern Company Services, Inc.	Common Stock Dividends Paid	115,800,000
	Professional Services	97,293,041
	Other Payments to SCS	
	Payroll Related	52,245,554
	Interchange	0
	Fuel Stock - Gas	267,692,748
	Pensions & Benefits	22,499,802
	Transmission Service	739,519
	Sales to SCS	
	Interchange	114,054,379
	Wholesale Contracts Billed by SCS	69,734,877
	Transmission Service	3,037,910
	Common Stock Sales	40,000,000
	Customer Bill Collection Remittance	56,424,098
	Income Taxes	93,872,161
	Professional Services	1,501,289
Southern Power Company	Purchased Power	14,677,759
	Sales to SPC	
	Distance Piece	538,046

Analysis of Diversification Activity

Summary of Affiliated Transfers and Cost Allocations

Company: Gulf Power Company

For the Year Ended December 31, 2012

Grouped by affiliate, list each contract, agreement, or other business transaction exceeding a cumulative amount of $300 in any one year, entered into between the Respondent and an affiliated business or financial organization, firm, or partnership identifying parties, amounts, dates, and product, asset, or service involved.

(a) Enter name of affiliate.
(b) Give description of type of service, or name the product involved.
(c) Enter contract or agreement effective dates.
(d) Enter the letter "p" if the service or product is purchased by the Respondent: "s" if the service or product is sold by the Respondent.
(e) Enter utility account number in which charges are recorded.
(f) Enter total amount paid, received, or accrued during the year for each type of service or product listed in column (c). Do not net amounts when services are both received and provided.

Name of Affiliate (a)	Type of Service and/or Name of Product (b)	Relevant Contract or Agreement and Effective Date (c)	Total Charge for Year "p" or "s" (d)	Account Number (e)	Dollar Amount (f)
Alabama Power Company	Capital Construction	None	P	309	13,984
	Fuel & Fuel Testing	None	P	500-509	491,807
	Generation Maintenance	None	P	510-514	637,994
	Distribution Maintenance	None	P	581, 588, 592, 595	21,452
	Transmission Transactions	None	P	566, 570	7,552
	Customer Expenses	None	P	903	383,106
	Materials	None	P	Various	298,902
	Misc. Business Transaction	None	P	Various	146,665
	Storm Charges	None	S	146	127,211
	Material	None	S	146	47,057
	Railcar Charges	None	S	146	100,730
	Misc. Business Trans.	None	S	146	139,696
Georgia Power Company	Plant Scherer Unit No. 3	Cost of Ownership	P	Various	49,188,907
	Materials	None	P	Various	739,186
	Misc. Business Transactions	None	P	Various	191,892
	Customer Service	None	P	903	169,792
	Material	None	S	146	250,997
	Railcar	None	S	146	33,407
	Misc. Business Trans.	None	S	146	879,161
Mississippi Power Company	Trans. Facilities Services	April 20, 1981	P	567	134,408
	Plant Daniel	Cost of Ownership	P	Various	119,381,294
	Materials	None	P	Various	15,043
	Storm Charges	None	P	820	69,950
	Misc. Business Transactions	None	P	Various	99,944
	Material	None	S	146	20,101
	Railcar	None	S	146	1,313,687
	Tow Boat	None	S	146	265,314
	Storm Charges	None	S	146	6,668
	Misc. Business Trans.	None	S	146	232,579
Southern Management Development, Inc.	Collection Remittance	None	P	234	241,075

Analysis of Diversification Activity

Summary of Affiliated Transfers and Cost Allocations

Company: Gulf Power Company
For the Year Ended December 31, 2012

Grouped by affiliate, list each contract, agreement, or other business transaction exceeding a cumulative amount of $300 in any one year, entered into between the Respondent and an affiliated business or financial organization, firm, or partnership identifying parties, amounts, dates, and product, asset, or service involved.
(a) Enter name of affiliate.
(b) Give description of type of service, or name the product involved.
(c) Enter contract or agreement effective dates.
(d) Enter the letter "p" if the service or product is purchased by the Respondent: "s" if the service or product is sold by the Respondent.
(e) Enter utility account number in which charges are recorded.
(f) Enter total amount paid, received, or accrued during the year for each type of service or product listed in column (c). Do not net amounts when services are both received and provided.

Name of Affiliate (a)	Type of Service and/or Name of Product (b)	Relevant Contract or Agreement and Effective Date (c)	Total Charge for Year "p" or "s" (d)	Account Number (e)	Dollar Amount (f)
Southern Nuclear Operating Company, Inc.	Misc. Business Transactions	April 8, 2008	P	234	714
	Misc. Business Transactions	April 8, 2008	S	146	42,795
Southern Company Services, Inc.	Common Stock Dividends Paid	None	P	238	115,800,000
	Service Agreement	January 1, 1984 Amended September 6, 1985	P	Various	441,173,876
	Interchange	February 17, 2000	P	Various	0
	Interchange	February 17, 2000	S	146	114,054,379
	Transmission Service	Various	P	234	739,519
	Transmission Service	Various	S	146	3,037,910
	Wholesale Contracts Billed by SCS	Various	S	143, 146	69,734,877
	Common Stock Sales	Various	S	Various	40,000,000
	Customer Bill Collection Remittance	Various	S	Various	56,424,098
	Income Taxes	Various	S	Various	93,872,161
	Professional Services	Various	S	146	1,501,289
	Occupancy	Various	S	146	597,732
	Misc. Business Transactions	None	S	146	27,521,308
Southern Power	Distance Piece	None	P	Various	331,464
	Purchased Power	None	P	234	14,677,759
	Distance Piece	None	S	146	538,046
	Misc. Business Transactions	None	S	146	45,745
Southern Linc	Materials	October 1, 1995	P	Various	419,827
	Misc. Business Transaction	October 1, 1995	P	Various	200,970
	Misc. Business Transaction	October 1, 1995	S	146	1,045

Analysis of Diversification Activity

Assets or Rights Purchased from or Sold to Affiliates

Company: Gulf Power Company

For the Year Ended December 31, 2012

Provide a summary of affiliated transactions involving asset transfers or the right to use assets.

Name of Affiliate	Description of Asset or Right	Cost/Orig. Cost	Accumulated Depreciation	Net Book Value	Fair Market Value	Purchase Price	Title Passed Yes/No
Purchases from Affiliates:		$	$	$	$	$	
Alabama Power Company	Misc. Materials	298,902		298,902		298,902	Yes
Georgia Power Company	Misc. Materials	739,186		739,186		739,186	Yes
Mississippi Power Company	Misc. Materials	15,043		15,043		15,043	Yes
Southern Linc	Misc. Materials	419,827		419,827		419,827	Yes
Southern Power	Distance Piece	501,716		501,716	331,464	331,464	Yes
Total						$ 1,804,422	
Sales to Affiliates:		$	$	$	$	Sales Price	
Alabama Power Company	Misc. Materials	47,057		47,057	47,132	47,057	Yes
Georgia Power Company	Misc. Materials	250,997		250,997	249,019	250,997	Yes
Mississippi Power Company	Misc. Materials	20,101		20,101	20,188	20,101	Yes
Southern Power Company	Distance Piece	538,046		538,046	355,466	538,046	Yes
Total						$ 856,201	

Analysis of Diversification Activity
Employee Transfers

Company: Gulf Power Company
For the Year Ended December 31, 2012

List employees earning more than $30,000 annually transferred to/from the utility to/from an affiliate company.

Company Transferred From	Company Transferred To	Old Job Assignment	New Job Assignment	Transfer Permanent or Temporary and Duration
FPC	APC	CSC Representative, Sr.	Sr Cust Ser Rep	Permanent
FPC	APC	Customer Rep, Sr.(PNS)	Sr Cust Ser Rep	Permanent
FPC	APC	Engineer I	Engineer I	Permanent
FPC	APC	Engineer I	Engineer, SR	Permanent
FPC	APC	Team Leader - Operations	Team Leader - Planning	Permanent
FPC	APC	Operations Manager	Operations & Maintenance Mgr	Permanent
FPC	APC	Power Delivery General Manag	Transmission VP	Permanent
FPC	GPC	Distribution Oper. Tech., III	Operator II	Permanent
FPC	GPC	Operator IV	Power System Coordinator II	Permanent
FPC	MPC	Operator IV	Gasification Team Leader	Permanent
FPC	SCS	Intern	Budget Analyst III	Permanent
FPC	SCS	Intern	Budget Analyst III	Permanent
FPC	SCS	Operator IV	Operations Technician I	Permanent
FPC	SCS	Accountant, SR	Auditor, Sr	Permanent
FPC	SCS	Independent Contractor	Auditor, Sr	Permanent
FPC	SCS	Power System Coordinator Sr	System Operator SR	Permanent
FPC	SCS	Training Analyst, Staff	Training Analyst, Staff	Permanent
FPC	SCS	President & CEO	President & CEO	Permanent
FPC	SNC	I & C Technician IV	Nuclear Plant Instructor, I	Permanent
APC	FPC	Sr Cust Ser Rep	Administrative Assistant, Sr	Permanent
APC	FPC	Team Leader - Operations	Team Leader - Operations	Permanent
APC	FPC	Power System Coordinator Sr	Power System Coordinator Sr	Permanent
GPC	FPC	Operator I	Distribution Coordinator I	Permanent
GPC	FPC	Forestry & R/W Specialist SR	Forestry Services Team Leader	Permanent
GPC	FPC	Operations Manager	Operations Manager	Permanent
GPC	FPC	Energy Efficiency Director	Marketing General Manager	Permanent
SCS	FPC	Ac Hangar Attend Sr	Maintenance Technician, II	Permanent
SCS	FPC	COOP - Technical	COOP - Technical	Permanent
SCS	FPC	Administrative Asst Exec	CSC Representative, Sr.	Permanent
SCS	FPC	Engineer I	P&C Test Engineer I	Permanent
SCS	FPC	ESS Analyst Staff	Accountant, Staff	Permanent
SCS	FPC	Senior Vice President & SPO	Sr. Vice President & SPO	Permanent

Analysis of Diversification Activity

Non-Tariffed Services and Products Provided by the Utility

Company: Gulf Power Company

For the Year Ended December 31, 2012

Provide the following information regarding all non-tariffed services and products provided by the utility.

Description of Product or Service (a)	Account No. (b)	Regulated or non-regulated (c)
Building Space/Office Furniture	929	Regulated / Non Regulated
Professional Services	Various	Regulated / Non Regulated
Material Transfers	154, 3XX, 5XX	Regulated / Non Regulated
Safety, Health and Wellness	921, 923, 925, 926	Regulated / Non Regulated
Miscellaneous Non-Electric Revenues-All Connect, Premium Surge, Commercial Surge	415	Non-regulated
Miscellaneous Service Revenues-Revenue protection fees	451	Regulated
Rent from Electric Property-Includes rent from pole attachments; from equipment devoted to electric operations including use of distribution lines and use of telecommunication transport assets by affiliates; land leases; use of cell towers on company land.	454	Regulated / Non Regulated
Other Electric Revenues-Energy Direct.com, Energy Services	456	Regulated / Non Regulated
Transmission Services	3XX	Regulated
Distribution Services	186	Regulated / Non Regulated
Wood Chip Sales	593	Regulated

Nonutility Property (Account 121)

Company: Gulf Power Company

For the Year Ended December 31, 2012

1. Give a brief description and state the location of Nonutility property included in Account 121.
2. Designate with a double asterisk any property which is leased to another company. State name of lessee and whether lessee is an associated company.
3. Furnish particulars (details) concerning sales, purchases, or transfers of nonutility property during the year.
4. List separately all property previously devoted to public service and give date of transfer to Account 121, Nonutility Property.
5. Minor items (5% of the balance at the end of the year), for Account 121 or $100,000, whichever is less) may be grouped by (1) previously devoted to public service, or (2) other property nonutility property.

Description and Location	Balance at beginning of year	Purchases, Sales, Transfers, etc.	Balance at end of year
Previously Devoted to Public Service:			
40 parcels of minor items previously devoted to Public Service.	447,929	(1,234)	446,695
Other Non-Utility Property:			
Blackwater Substation Site	181,083	0	181,083
Operation Center Additional Land	11,111,568	0	11,111,568
Surge Protection Equipment	3,771,958	212,505	3,984,463
3 parcels of minor items devoted to Other Nonutility Property.	19,699	0	19,699
Totals	15,532,237	211,271	15,743,508

Number of Electric Department Employees

Company: Gulf Power Company

For the Year Ended December 31, 2012

1. The data on number of employees should be reported for the payroll period ending nearest to October 31, or any payroll period ending 60 days before or after October 31.
2. If the respondent's payroll for the reporting period includes any special construction personnel, include such employees on line 3, and show the number of such special construction employees in a footnote.
3. The number of employees assignable to the electric department from joint functions of combination utilities may be determined by estimate, on the basis of employee equivalents. Show the estimated number of equivalent employees attributed to the electric department from joint functions.

1. Payroll Period Ended (Date)	12/31/2012	
2. Total Regular Full-Time Employees		1,404
3. Total Part-Time and Temporary Employees		12
4. Total Employees		1,416

Details
Total Employees do not include SCS Employees On-Site.

Particulars Concerning Certain Income Deductions and Interest Charges Accounts

Company: Gulf Power Company

For the Year Ended December 31, 2012

Report the information specified below, in the order given, for the respective income deduction and interest charges accounts. Provide a subheading for each account and a total for the account. Additional columns may be added if deemed appropriate with respect to any account.

(a) Miscellaneous Amortization (Account 425) -- Describe the nature of items included in this account, the contra account charged, the total of amortization charges for the year, and the period of amortization.

(b) Miscellaneous Income Deductions -- Report the nature, payee, and amount of other income deductions for the year as required by Accounts 426.1, Donations; 426.2, Life Insurance; 426.3, Penalties; 426.4, Expenditures for Certain Civic, Political and Related Activities; and 426.5, Other Deductions, of the Uniform System of Accounts. Amounts of less than 5% of each account total for the year (or $1,000, whichever is greater) may be grouped by classes within the above accounts.

(c) Interest on Debt to Associated Companies (Account 430) -- For each associated company to which interest on debt was incurred during the year, indicate the amount and interest rate respectively for (a) advances on notes, (b) advances on open account, (c) notes payable, (d) accounts payable, and (e) other debt, and total interest. Explain the nature of other debt on which interest was incurred during the year.

(d) Other Interest Expense (Account 431) -- Report particulars (details) including the amount and interest rate for other interest charges incurred during the year.

Item	Amount
Miscellaneous Amortization of Utility (Account 425)	
Plant Acquisition Adjustment-Plant Scherer Common Facilities (Contra Acct 114	
Amortized over a period of 34 years.)	255,312
Subtotal - 425	255,312
Miscellaneous Income Deductions (Account 426)	
Account 426.1 Donations	
Religious	6,200
Charitable	17,975
Scientific	15,250
Health & Human Services	67,275
Community	121,775
Civic	79,694
Education	1,685,321
Miscellaneous Donations	31,647
Donations made indirectly through SCS	25
Donations-Environmental	0
Donations-Gulf Power Foundation	304,821
Donations-Economic Development Fund	200,000
Subtotal - 426.1	2,429,983
Account 426.3 - Penalties	37,992
Account 426.4 Expenditures for Certain Civic, Political & Related Activities	
Salaries and Wages	826,626
Employee Expenses	85,286
Office and Related Expenses	124,010
Organizations & Dues	165,079
Outside Services Employed/Consultants	1,082,018
PAC Expenses	10,830
Subtotal - 426.4	2,293,849
Account 426.5 Other Deductions	
Miscellaneous Non-operating Expenses	611,251
Employee Fees & Dues in Civic & Social Clubs	27,612
Energy Select Sales	43,544
Subtotal - 426.5	682,407

Particulars Concerning Certain Income Deductions and Interest Charges Accounts

Company: Gulf Power Company

For the Year Ended December 31, 2012

Report the information specified below, in the order given, for the respective income deduction and interest charges accounts. Provide a subheading for each account and a total for the account. Additional columns may be added if deemed appropriate with respect to any account.

(a) Miscellaneous Amortization (Account 425) – Describe the nature of items included in this account, the contra account charged, the total of amortization charges for the year, and the period of amortization.

(b) Miscellaneous Income Deductions – Report the nature, payee, and amount of other income deductions for the year as required by Accounts 426.1, Donations; 426.2, Life Insurance; 426.3, Penalties; 426.4, Expenditures for Certain Civic, Political and Related Activities; and 426.5, Other Deductions, of the Uniform System of Accounts. Amounts of less than 5% of each account total for the year (or $1,000, whichever is greater) may be grouped by classes within the above accounts.

(c) Interest on Debt to Associated Companies (Account 430) – For each associated company to which interest on debt was incurred during the year, indicate the amount and interest rate respectively for (a) advances on notes, (b) advances on open account, (c) notes payable, (d) accounts payable, and (e) other debt, and total interest. Explain the nature of other debt on which interest was incurred during the year.

(d) Other Interest Expense (Account 431) – Report particulars (details) including the amount and interest rate for other interest charges incurred during the year.

Item	Amount
Account 430 Interest on Debt to Associated Companies	
Commercial Paper Program (Variable Interest Rate ranging from high of 0.279 & low of 0.195)	172,476
Subtotal - 430	**172,476**
Account 431 Other Interest Expense	
Other Interest Expense (Various)	63,416
Other Interest Expense-Customer Deposits (Residential 2% and Non-Residential 2-3% determined by meeting certain criteria)	1,701,654
Other Interest Expense-Note Payable (7.7%)	99,882
Other Interest Expense-Tax Assessment (Various)	348,703
Other Interest Expense-FIN 48-Federal (Various)	(174,567)
Other Interest Expense-FIN 48-State (Various)	(39,268)
Other Interest Expense-Environmental Over/Under Recovered (30 day Commercial Paper Rate)	5,610
Other Interest Expense-Fuel Over Recovery (30 day Commercial Paper Rate)	22,080
Other Interest Expense-Purchase Power Capacity Over Recovery (30 day Commercial Paper Rate)	5,235
Other Interest Expense-Wholesale-Blountstown-Fuel (30 day Commercial Paper Rate)	(10)
Other Interest Expense-Wholesale-Blountstown-Environmental (30 day Commercial Paper Rate)	8
Other Interest Expense-Wholesale-FPU-Fuel (30 day Commercial Paper Rate)	442
Other Interest Expense-Wholesale-FPU-Environmental (30 day Commercial Paper Rate)	152
Subtotal - 431	**2,033,517**
Total	**7,985,536**

Page 463.1

Schedule C-32 | NON-UTILITY OPERATIONS UTILIZING UTILITY ASSETS | Page 1 of 1

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide an analysis of all non-utility operations such as orange groves, parking lots, etc. that utilized all or part of any utility plant that are not included in Schedule C-31.

Type of Data Shown:
_X_ Projected Test Year Ended 12/31/14
_X_ Prior Year Ended 12/31/13
___ Historical Test Year Ended 12/31/12
Witness: S. D. Ritenour

(1) Line No.	(2) Account No.	(3) Description	(4) Original Purchase Cost	(5) Test Year Revenues (All Accts. 454)	(6) Expense Amounts	(7) Net Revenues
1		Not applicable to test year or prior year due to non-utility operations being removed from rate base.				

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide a schedule for the last four prior years and the test year of other operation and maintenance expense summary by average customer, selected growth indices, selected growth rates and average number of customers.

Type of Data Shown:
X Projected Test Year Ended 12/31/14
X Prior Year Ended 12/31/13
X Historical Years Ended 12/31/10-12/31/12
Witness: R.J. McMillan

(1) Line No.	(2) Description	(3) 2014 Test Year	(4) 2013 Prior Year	(5) 2012 Actual	(6) 2011 Actual	(7) 2010 Actual
1	SUMMARY OF OTHER O&M EXPENSES, LESS FUEL-RELATED AND SCHERER EXPENSES (DOLLARS PER CUSTOMER)					
2	Power Production Expense	301.68	261.88	283.28	305.08	290.22
3	Transmission Expenses	31.03	27.25	25.02	28.53	21.92
4	Distribution Expenses	103.16	98.92	93.70	100.12	92.59
5	Customer Account Expenses	58.31	56.15	48.80	50.19	50.51
6	Customer Service Expenses	87.07	87.13	87.05	69.58	49.50
7	Sales Expenses	3.14	3.14	2.29	2.66	2.47
8	Administration & General Expenses	194.61	189.70	168.77	161.90	159.31
9	Total Other O & M Expenses	778.99	724.17	708.90	718.06	666.52
10	GROWTH INDICES					
11	Consumer Price Index	241.160	234.720	229.660	224.940	218.080
12	Average Customer	443,351	438,048	434,441	432,403	430,030
13	CPI Percent Increase	2.744%	2.203%	2.098%	3.146%	1.641%
14	Average Customer Percent Increase	1.211%	0.830%	0.471%	0.552%	0.426%
15	Index Percent CPI x Customer Growth	1.07161	1.03051	1.00000	0.97485	0.93994
16	Average Customer Increase	5,303	3,607	2,038	2,373	1,824

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide a schedule for the last four prior years and the test year of other operation and maintenance expense summary by average customer, selected growth indices, selected growth rates and average number of customers.

Type of Data Shown:
X Projected Test Year Ended 12/31/14
X Prior Year Ended 12/31/13
X Historical Years Ended 12/31/10-12/31/12
Witness: R.J. McMillan

(1) Line No.	(2) Description	(3) 2014 Test Year	(4) 2013 Prior Year	(5) 2012 Actual	(6) 2011 Actual	(7) 2010 Actual
1	DOLLAR AMOUNTS, IN CURRENT DOLLARS AND ANNUAL GROWTH RATES FOR :					
2	O&M Expense less Fuel per KWH Sold	0.0300	0.0278	0.0280	0.0272	0.0244
3	Capital Cost per Installed Watt of Electricity	1023.06	982.22	968.94	855.45	826.29
4	Revenue per KWH Sold	0.1153	0.1084	0.1059	0.1111	0.1136
5	AVERAGE NUMBER OF CUSTOMERS					
6	Residential	387,860	383,073	379,897	378,157	375,847
7	Commercial	54,639	54,129	53,706	53,409	53,349
8	Industrial	279	273	267	273	275
9	Street Lighting	572	572	570	562	557
10	Other Sales to Public Authorities	1	1	1	2	2
11	Total	443,351	438,048	434,441	432,403	430,030

Supporting Schedules: C-40 Recap Schedules: C-36

Schedule C-34 | STATISTICAL INFORMATION | Page 1 of 1

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide the following statistical data for the company, by calendar year for the most recent 5 historical years.

Type of Data Shown:
___Projected Test Year Ended 12/31/14
___Prior Year Ended 12/31/13
_X_Historical Years Ended 12/31/08 - 12/31/12
Witness: J. A. McQuagge, P. C. Caldwell, R. W. Grove, R. J. Alexander

(1) Line No.	(2) Description	(3) Year 2008	(4) Year 2009	(5) Year 2010	(6) Year 2011	(7) Year 2012	(8) Average Annual Growth Rate (%)
1	THE LEVEL AND ANNUAL GROWTH RATES FOR:						
2	Peak Load (MW)	2,541	2,546	2,553	2,535	2,351	(1.92)
3	Peak Load Per Customer (KW)	5.92	5.95	5.94	5.86	5.41	(2.22)
4	Energy Sales (MWH)	11,929,723	11,276,304	11,750,660	11,407,228	10,987,828	(2.04)
5	Energy Sales Per Customer (KWH)	27,789	26,334	27,325	26,381	25,292	(2.33)
6	Number of Customers (Average)	429,303	428,206	430,030	432,403	434,441	0.30
7	Installed Generating Capacity (MW)	2,659	2,659	2,663	2,663	2,663	0.03
8	Population of Service Area	793,570	795,760	800,920	807,070	813,960	0.64
9	End of Year Miles of Distribution Lines	7,570	7,642	7,684	7,710	7,723	0.50
10	End of Year Miles of Jurisdictional Transmission Lines	1,594	1,595	1,610	1,591	1,587	(0.11)

Supporting Schedules:

Recap Schedules:

Schedule C-35 | PAYROLL AND FRINGE BENEFIT INCREASES COMPARED TO CPI | Page 1 of 2

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide the following payroll and fringe benefits data for the historical test year and two prior years. If a projected test year is used, provide the same data for the projected test year and prior years to include two historical years.

Type of Data Shown:
X Projected Test Year Ended 12/31/14
X Prior Year Ended 12/31/13
__ Historical Year Ended 12/31/10-12/31/12
Witness: R.J. McMillan

(1) Line No.	(2)	(3) 2014 $ Amount	(4) 2014 % Inc	(5) 2014 % CPI	(6) 2013 $ Amount	(7) 2013 % Inc	(8) 2013 % CPI
1	Total Company Basis						
2	Base Payroll	107,379,480	2.45	2.74	104,807,220	4.94	2.20
3	Variable Payroll	16,602,482	3.98		15,967,515	11.07	
4	Total Payroll	123,981,962	2.66		120,774,735	5.71	
5	Gross Average Salary	84,745	2.94		82,328	1.97	
6	Fringe Benefits (including capitalized & clearing portions)						
7	Medical and Other Group Insurance	14,738,651	9.81		13,421,866	15.35	
8	Educational Assistance	175,000	6.06		165,000	-7.58	
9	Relocation Assistance	1,392,159	0.00		1,392,159	-9.34	
10	Other Employee Benefits	400,044	5.53		379,096	-30.04	
11	Pension	9,280,000	-1.90		9,460,000	152.81	
12	Supplemental Pension	2,220,000	5.71		2,100,000	16.58	
13	Employee Savings Plan	4,549,918	3.00		4,417,396	11.25	
14	Post-Retirement Life	880,000	-3.30		910,000	1.17	
15	Post-Retirement Medical (less Subsidy)	2,500,000	4.17		2,400,000	-6.30	
16	Post-Retirement Supplemental	21,986	7.00		20,548	-47.87	
17	Worker's Compensation	68,500	-1.44		69,500	9.84	
18	FICA, Federal, State Unemployment Taxes	8,462,000	2.84		8,228,000	-5.64	
19	Sub-Total - Fringes	44,688,258	4.01		42,963,565	20.38	
20	Total Payroll and Fringes	168,670,220	3.01		163,738,300	9.21	
21	Average Employees	1,463	-0.27		1,467	3.67	
22	Payroll and Fringes Per Employee	115,291	3.29		111,614	5.33	

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Supporting Schedules: C-40

Recap Schedules:

Schedule C-35 | PAYROLL AND FRINGE BENEFIT INCREASES COMPARED TO CPI | Page 2 of 2

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide the following payroll and fringe benefits data for the historical, test year and two prior years. If a projected test year is used, provide the same data for the projected test year and prior years to include two historical years.

Type of Data Shown:
__ Projected Test Year Ended 12/31/14
__ Prior Year Ended 12/31/13
X Historical Year Ended 12/31/10-12/31/12
Witness: R.J. McMillan

(1) Line No.	(2)	(3) 2012 $ Amount	(4) 2012 % Inc	(5) 2012 % CPI	(6) 2011 $ Amount	(7) 2011 % Inc	(8) 2011 % CPI	(9) 2010 $ Amount
1	Total Company Basis							
2	Base Payroll	99,870,109	5.08	2.10	95,042,356	1.63	3.15	93,519,899
3	Variable Payroll	14,376,558	4.43		13,766,852	-4.25		14,377,271
4	Total Payroll	114,246,667	5.00		108,809,208	0.85		107,897,170
5	Gross Average Salary	80,740	2.18		79,019	-1.28		80,042
6	Fringe Benefits (including capitalized & clearing portions)							
7	Medical and Other Group Insurance	11,635,381	6.60		10,915,285	9.90		9,931,871
8	Educational Assistance	178,527	9.55		162,969	29.46		125,882
9	Relocation Assistance	1,535,501	-51.39		3,158,626	96.44		1,607,943
10	Other Employee Benefits	541,891	6.95		506,661	-16.97		610,235
11	Pension	3,742,009	332.28		(1,611,013)	-486.84		416,453
12	Supplemental Pension	1,801,307	8.65		1,657,932	-5.06		1,746,329
13	Employee Savings Plan	3,970,794	6.54		3,727,047	3.01		3,618,135
14	Post-Retirement Life	899,507	5.58		851,976	-3.18		879,965
15	Post-Retirement Medical (less Subsidy)	2,561,360	-9.65		2,834,947	-13.17		3,264,856
16	Post-Retirement Supplemental	39,416	-10.37		43,974	-13.86		51,050
17	Worker's Compensation	63,274	4.14		60,758	-19.48		75,454
18	FICA, Federal, State Unemployment Taxes	8,719,791	8.54		8,033,394	8.50		7,404,103
19	Sub-Total - Fringes	35,688,758	17.62		30,342,556	2.05		29,732,276
20	Total Payroll and Fringes	149,935,425	7.75		139,151,764	1.11		137,629,446
21	Average Employees	1,415	2.76		1,377	2.15		1,348
22	Payroll and Fringes Per Employee	105,961	4.86		101,054	-1.02		102,099

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Supporting Schedules: C-40

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide a comparison of the change in operation and maintenance expenses (excluding fuel) for the last three years and the test year to CPI.

Type of Data Shown:
X Projected Test Year Ended 12/31/14
X Prior Year Ended 12/31/13
X Historical Year Ended 12/31/11-12/31/12
Witness: R.J. McMillan

(1) Line No.	(2) Description	(3) 2014	(4) 2013	(5) 2012	(6) 2011
1	Non-Fuel Operations & Maintenance Expenses				
2	(Excluding ECCR & ECRC & Transmission Energy &				
3	Capacity: Includes Other Regulatory Adjustments)	295,916,000	268,129,000	261,069,000	272,425,000
4	Percent Change in Non-Fuel Operations & Maintenance				
5	Expense Over Previous Year	10.363%	2.704%	-4.168%	11.878%
6	Percent Change in CPI Over Previous Year	2.744%	2.203%	2.098%	3.146%
7	Difference Between Change in CPI and Non-Fuel				
8	Operations & Maintenance Expense	7.619%	0.501%	-6.266%	8.732%

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Supporting Schedules: C-1, C-33, C-40

Recap Schedules:

Schedule C-37 | O&M BENCHMARK COMPARISON BY FUNCTION | Page 1 of 1

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: For test year functionalized O&M expenses, provide the benchmark variances.

(000's)

Type of Data Shown:
_X_Projected Test Year Ended 12/31/14
___Prior Year Ended 12/31/13
___Historical Year Ended 12/31/12
Witness: R. J. McMillan

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Line No.	Function	Test Year Total Company Per Books	O&M Adjustments	Adjusted Test Year O&M	Base Year Adjusted O&M	Compound Multiplier	Test Year Benchmark (6) x (7)	Unadjusted Benchmark Variance	Adjusted Benchmark Variance
1	Production - Steam	431,622	(339,899)	91,723	95,311	1.05007	100,083	331,539	(8,360)
2	Production - Other	321,851	(310,709)	11,142	7,312	1.05007	7,678	314,173	3,464
3	Production - Other Power Supply	92,144	(88,273)	3,871	4,312	1.05007	4,528	87,616	(657)
4	Transmission	27,386	(13,653)	13,733	11,320	1.07161	12,131	15,255	1,602
5	Distribution	45,738	(3,668)	42,070	39,877	1.07161	42,733	3,005	(663)
6	Customer Accounts	25,850	(55)	25,795	24,532	1.07161	26,289	(439)	(494)
7	Customer Service and Information	38,602	(21,958)	16,644	18,861	1.07161	20,212	18,390	(3,568)
8	Sales Expense	1,391	(220)	1,171	945	1.07161	1,013	378	158
9	Administrative and General	88,996	771	89,767	73,482	1.07161	78,744	10,252	11,023
10	Total	1,073,580	(777,664)	295,916	275,952		293,411	780,169	2,505

Supporting Schedules: C-38, C-39, C-40

Recap Schedules: C-41

Schedule C-38 | O&M ADJUSTMENTS BY FUNCTION | Page 1 of 2

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide the detail of adjustments made to test year per books O&M expenses by function.

(000's)

Type of Data Shown:
_X_Projected Test Year Ended 12/31/14
___Prior Year Ended 12/31/13
___Historical Year Ended 12/31/12
Witness: R. J. McMillan

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
Line No.	Function	Test Year System Per Books	Direct Fuel, Fuel-Related Expenses and Purchased Power	ECCR	ECRC	Tallahassee Liaison Expenses	Plant Scherer/ UPS	Marketing Support Activities	Management Financial Planning	Economic Development
1	Production									
2	Steam Production	431,622	(303,538)		(24,672)		(10,072)			
3	Other Production	321,851	(310,241)		(51)					
4	Other Power Supply	92,144	(88,018)							
5	Total Production	845,617	(701,797)	0	(24,723)	0	(10,072)	0	0	0
6	Transmission	27,386	(13,624)		(9)		(4)			
7	Distribution	45,738			(3,576)					
8	Customer Accounts	25,850								
9	Customer Service & Information	38,602		(21,931)						
10	Sales Expenses	1,391						(156)		(62)
11	Administrative & General	88,996	(100)	(1,589)	(769)	(306)	(2,616)		(41)	(1)
12	Total Adjustments	1,073,580	(715,521)	(23,520)	(29,077)	(306)	(12,692)	(156)	(41)	(63)

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Supporting Schedules:

Recap Schedules: C-37, C-41

Schedule C-38 | O&M ADJUSTMENTS BY FUNCTION | Page 2 of 2

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide the detail of adjustments made to test year per books O&M expenses by function.

(000's)

Type of Data Shown:
X Projected Test Year Ended 12/31/14
___Prior Year Ended 12/31/13
___Historical Year Ended 12/31/12
Witness: R. J. McMillan

(1) Line No.	(2) Function	(3) Wholesale Sales Expense	(4) Advertising	(5) Rate Case Expenses	(6) Property Insurance Reserve	(7) Hiring Lag	(8) Perdido Unit 3	(9) Plant Scholz	(10) Subtotal Adjustments	(11) Total Adjusted O&M
1	Production									
2	Steam Production					(142)		(1,475)	(339,899)	91,723
3	Other Production					(17)	(400)		(310,709)	11,142
4	Other Power Supply	(255)							(88,273)	3,871
5	Total Production	(255)	0	0	0	(159)	(400)	(1,475)	(738,881)	106,736
6	Transmission					(16)			(13,653)	13,733
7	Distribution					(92)			(3,668)	42,070
8	Customer Accounts					(55)			(55)	25,795
9	Customer Service & Information					(27)			(21,958)	16,644
10	Sales Expenses					(2)			(220)	1,171
11	Administrative & General		(30)	930	5,500	(207)			771	89,767
12	Total Adjustments	(255)	(30)	930	5,500	(558)	(400)	(1,475)	(777,664)	295,916

Supporting Schedules:

Recap Schedules: C-37, C-41

Schedule C-39 BENCHMARK YEAR RECOVERABLE O&M EXPENSES BY FUNCTION Page 1 of 1

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide adjustments to benchmark year O&M expenses related to expenses recoverable through mechanisms other than base rates. Explain any adjustments.

Type of Data Shown:
_X_ Projected Test Year Ended 12/31/12
___ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
___ Historical Year Ended 12/31/12
Witness: R. J. McMillan

($000's)

(1) Line No.	(2) Function	(3) 2012 System Per Books	(4) Eliminate Recoverable Fuel and Purchased Power	(5) Eliminate Recoverable ECRC	(6) Eliminate Recoverable ECCR	(7) Other Regulatory O&M Adjustments	(8) 2012 Adjusted System Amount	(9) Function Adjustments	(10) 2012 Adjusted System Amount (incl Function adjs)
1	Production	882,030	(730,362)	(30,440)	0	(14,293)	106,935	0	106,935
2	Transmission	14,269	(2,657)	0	0	(292)	11,320	0	11,320
3	Distribution	43,781	0	(2,185)	0	(1,032)	40,564	(687)	39,877
4	Customer Accounts	24,723	0	0	0	(1,054)	23,669	863	24,532
5	Customer Service & Information	38,757	0	0	(18,070)	(465)	20,222	(1,361)	18,861
6	Sales Expense	1,097	0	0	0	(152)	945	0	945
7	Administrative & General	82,178	(300)	(706)	(1,241)	(7,634)	72,297	1,185	73,482
8	Total O&M Expenses by Function	1,086,835	(733,319)	(33,331)	(19,311)	(24,922)	275,952	0	275,952

Supporting Schedules:

Recap Schedules: C-37, C-41

Schedule C-40 | O&M COMPOUND MULTIPLIER CALCULATION | Page 1 of 1

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: For each year since the benchmark year, provide the amounts and percent increases associated with customers and average CPI. Show the calculation for each compound multiplier.

Type of Data Shown:
X Projected Year Ended 12/31/14
X Prior Year Ended 12/31/13
X Historical Year Ended 12/31/12
Witness: R. J. McMillan

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
		Total Average Customers			Average CPI-U			Inflation and Growth
Line No.	Year	Amount	% Increase *	Compound Multiplier **	Amount***	% Increase *	Compound Multiplier **	Compound Multiplier (5) x (8)
1	2012	434,441		1.00000	229.660		1.00000	1.00000
2	2013	438,048	0.830%	1.00830	234.720	2.203%	1.02203	1.03051
3	2014	443,351	1.211%	1.02051	241.160	2.744%	1.05007	1.07161

* Percent change from prior year to current year.

** Current year Col. (5) or Col. (8) divided by the base year (2012) in the same column.

***Based on CPI: Urban Consumers; Moody's Analytics, Nov. 2012

Supporting Schedules:

Recap Schedules: C-33, C-36, C-37

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide a schedule of operation and maintenance expense by function for the test year, the benchmark year and the variance. For each functional benchmark variance, provide the reason(s) for the difference.

Type of Data Shown:
X Projected Test Year Ended 12/31/14
_____ Prior Year Ended 12/31/13
_____ Historical Year Ended 12/31/12
Witness: R. J. McMillan, R. W. Grove, P. C. Caldwell, J. A. McQuagge, M. D. Neyman, C. J. Erickson, A. G. Strickland

(1) LINE NO.	(2) INDEX	(3) PAGE NO.
1	Summary Justification for each Functional Benchmark Variance	
2	Summary of Test Year Benchmark Expenses	2
3	(A) Total Production Summary	
4	(1) Steam Production	3
5	(2) Production Other	4
6	(3) Production Other Power Supply	6
7	(B) Transmission	7
8	(C) Distribution	9
9	(D) Customer Accounts	10
10	(E) Customer Service & Information	11
11	(F) Sales	12
12	(G) Administrative & General	14

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide a schedule of operation and maintenance expense by function for the test year, the benchmark year and the variance. For each functional benchmark variance, provide the reason(s) for the difference.

Type of Data Shown:
_X_ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
___ Historical Year Ended 12/31/12
Witness: R. J. McMillan, R. W. Grove, P. C. Caldwell, J. A. McQuagge, M. D. Neyman, C. J. Erickson, A. G. Strickland

(000's)

TOTAL ADJUSTED O&M LESS FUEL, PURCHASED POWER, ECCR AND ECRC
BENCHMARK VARIANCE BY FUNCTION
2012 ALLOWED COMPARED TO TEST YEAR REQUEST EXPENSES

Line No.	(2)	(3)	(4)	(5)	(6)
(1)					
1		2012	Test Year	Test Year	
2	Description	Allowed	Benchmark	Request	Variance
3	Steam Production	95,311	100,083	91,723	(8,360)
4	Other Production	7,312	7,678	11,142	3,464
5	Other Power Supply	4,312	4,528	3,871	(657)
6	Total Production	106,935	112,289	106,736	(5,553)
7	Transmission	11,320	12,131	13,733	1,602
8	Distribution	39,877	42,733	42,070	(663)
9	Customer Accounts	24,532	26,289	25,795	(494)
10	Customer Service & Information	18,861	20,212	16,644	(3,568)
11	Sales	945	1,013	1,171	158
12	Administrative & General	73,482	78,744	89,767	11,023
13	Total Adjusted O&M	275,952	293,411	295,916	2,505

Supporting Schedules: C-37, C-38, C-39

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide a schedule of operation and maintenance expense by function for the test year, the benchmark year and the variance. For each functional benchmark variance, provide the reason(s) for the difference.

Type of Data Shown:
_X_ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
___ Historical Year Ended 12/31/12
Witness: R. W. Grove

STEAM PRODUCTION

Line No.		($000)
1		
2	2012 Allowed	95,311
3	Test Year Adjusted Benchmark	100,083
4	Test Year Adjusted Request	91,723
5	System Benchmark Variance	(8,360)
6	Description	
7	N/A	

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide a schedule of operation and maintenance expense by function for the test year, the benchmark year and the variance. For each functional benchmark variance, provide the reason(s) for the difference.

Type of Data Shown:
_X_ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
___ Historical Year Ended 12/31/12
Witness: R. W. Grove

OTHER PRODUCTION

Line No.		($000)
1		
2	2012 Allowed	7,312
3	Test Year Adjusted Benchmark	7,678
4	Test Year Adjusted Request	11,142
5	System Benchmark Variance	3,464
6	Description	Variance
7	1. Heat Recovery Steam Generator (HRSG)	2,000
8	2. Plant Smith Labor to Gas CC	800
9	3. Plant Smith CC and Perdido Planned Outage	800
10	4. Other	(136)
11		3,464

Supporting Schedules: C-37, C-38, C-39

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide a schedule of operation and maintenance expense by function for the test year, the benchmark year and the variance. For each functional benchmark variance, provide the reason(s) for the difference.

Type of Data Shown:
_X_ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
___ Historical Year Ended 12/31/12
Witness: R. W. Grove

Line No.

OTHER PRODUCTION

1 Justification

2 1. Heat Recovery Steam Generator (HRSG) - Work on the Heat Recovery Steam Generator (HRSG) in 2014 is budgeted to be $2,000,000 more than was
3 allowed in the 2012 rate case. The structural corrosion associated with the saltwater cooling towers continues to require the levels of maintenance
4 budgeted in 2014 and beyond.

5 2. Plant Smith Labor to Gas Combined Cycle (CC) - Plant Smith shifted $800,000 in labor dollars from the coal side of the plant to help operate and
6 maintain the gas CC. When you examine the Production Steam labor there is a corresponding decrease in labor.

7 3. Plant Smith CC and Perdido Planned Outage - Planned Outage work on the Smith CC and the Perdido facilities are $800,000 more than the prior test
8 year. Once again, although there in an increase in Production Other Planned Outages, there is a corresponding decrease in the Planned Outage work for
9 Production Steam.

10 4. Other

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide a schedule of operation and maintenance expense by function for the test year, the benchmark year and the variance. For each functional benchmark variance, provide the reason(s) for the difference.

Type of Data Shown:
_X_ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
___ Historical Year Ended 12/31/12
Witness: R. W. Grove

Line No.

OTHER POWER SUPPLY

Line No.		($000)
1		
2	2012 Allowed	4,312
3	Test Year Adjusted Benchmark	4,528
4	Test Year Adjusted Request	3,871
5	System Benchmark Variance	(657)
6	Description	
7	N/A	

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide a schedule of operation and maintenance expense by function for the test year, the benchmark year and the variance. For each functional benchmark variance, provide the reason(s) for the difference.

Type of Data Shown:
_X_ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
___ Historical Year Ended 12/31/12
Witness: P. C. Caldwell

Line No.		TRANSMISSION
1		(000's)
2	2012 Allowed	11,320
3	Test Year Adjusted Benchmark	12,131
4	Test Year Adjusted Request	13,733
5	System Benchmark Variance	1,602
6	Description	Variance
7	1. Transmission Vegetation Management	940
8	2. Transmission Line Maintenance Programs	583
9	3. Transmission Engineering and Supervision	309
10	4. Other	(230)
11		1,602

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide a schedule of operation and maintenance expense by function for the test year, the benchmark year and the variance. For each functional benchmark variance, provide the reason(s) for the difference.

Type of Data Shown:
_X_ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
___ Historical Year Ended 12/31/12
Witness: P. C. Caldwell

Line No.

TRANSMISSION

1 Justification

2 1. The Transmission Vegetation Management category is $940,000 over the benchmark due to additional work that is needed along our NERC regulated
3 230 kV corridors.

4 2. Transmission Line Maintenance Programs category is $583,000 over the benchmark due to an increase in Gulf's maintenance repairs. Gulf's
5 inspection program indicates a shift in the type of repairs needed on our transmission lines in 2014 from total pole replacements (infrastructure
6 replacement capital) to more minor repairs (maintenance expenses) on the existing structures that will prolong the life of the asset. This is a good
7 indication that our inspection, ground line treatment and replacement program is working. As the pole replacements decrease, we expect to see
8 this increase in maintenance activities, and with a maturing program we expect this trend to continue into the future.

9 3. Transmission Engineering and Supervision category is $309,000 over the benchmark due to a Commission adjustment in the 2012 Gulf Rate Case
10 related to vacancies, which existed at the time of the rate hearing. The dollars and the positions were then and are now required to effectively and
11 efficiently perform the transmission function. Gulf filled the vacancies in Transmission and remains at full staff.

12 4. N/A

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide a schedule of operation and maintenance expense by function for the test year, the benchmark year and the variance. For each functional benchmark variance, provide the reason(s) for the difference.

Type of Data Shown:
_X_ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
___ Historical Year Ended 12/31/12
Witness: J. A. McQuagge

DISTRIBUTION ACCOUNTS

Line No.		(000's)
1		
2	2012 Allowed	39,877
3	Test Year Adjusted Benchmark	42,733
4	Test Year Adjusted Request	42,070
5	System Benchmark Variance	(663)
6	Description	
7	N/A	

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide a schedule of operation and maintenance expense by function for the test year, the benchmark year and the variance. For each functional benchmark variance, provide the reason(s) for the difference.

Type of Data Shown:
_X_ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
___ Historical Year Ended 12/31/12
Witness: M. D. Neyman, C. J. Erickson

Line No.	CUSTOMER ACCOUNTS	
1		($000)
2	2012 Allowed	24,532
3	Test Year Adjusted Benchmark	26,289
4	Test Year Adjusted Request	25,795
5	System Benchmark Variance	(494)
6	Description	
7	N/A	

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide a schedule of operation and maintenance expense by function for the test year, the benchmark year and the variance. For each functional benchmark variance, provide the reason(s) for the difference.

Type of Data Shown:
X Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
___ Historical Year Ended 12/31/12
Witness: A. G. Strickland

Line No.	CUSTOMER SERVICE & INFORMATION	
1		($000)
2	2012 Allowed	18,861
3	Test Year Adjusted Benchmark	20,212
4	Test Year Adjusted Request	16,644
5	System Benchmark Variance	(3,568)
6	Description	
7	N/A	

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide a schedule of operation and maintenance expense by function for the test year, the benchmark year and the variance. For each functional benchmark variance, provide the reason(s) for the difference.

Type of Data Shown:
_X_ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
___ Historical Year Ended 12/31/12
Witness: A. G. Strickland

SALES

Line No.		($000)
1		
2	2012 Allowed	945
3	Test Year Adjusted Benchmark	1,013
4	Test Year Adjusted Request	1,171
5	System Benchmark Variance	158
6	Description	Variance
7	1. Administrative Expenses	126
8	2. Economic Development Programs/Projects	32
9		158

Supporting Schedules: C-37, C-38, C-39

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide a schedule of operation and maintenance expense by function for the test year, the benchmark year and the variance. For each functional benchmark variance, provide the reason(s) for the difference.

Type of Data Shown:
_X_ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
___ Historical Year Ended 12/31/12
Witness: A. G. Strickland

Line No.

SALES

1 Justification

2 1. Administrative Expenses - Gulf has allocated additional resources to allow the company to focus more on economic development. Therefore, the
3 increase is primarily due to the addition of an economic development analyst position and the associated costs and additional travel cost due to
4 increased industrial recruitment efforts.

5 2. Economic Development Programs/Projects - Gulf has allocated more resources to allow the company to focus more on economic development.
6 Therefore, the increase is due to increased cost for economic programs, events and projects.

7 3. N/A

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide a schedule of operation and maintenance expense by function for the test year, the benchmark year and the variance. For each functional benchmark variance, provide the reason(s) for the difference.

Type of Data Shown:
_X_ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
___ Historical Year Ended 12/31/12
Witness: C. J. Erickson

Line No.		A&G
1		(000's)
2	2012 Allowed	73,482
3	Test Year Adjusted Benchmark	78,744
4	Test Year Adjusted Request	89,767
5	System Benchmark Variance	11,023
6	Description	Variance
7	1. Pension Expense	5,871
8	2. Property Damage Accrual	5,249
9	3. Rate Case Expense	880
10	4. Other	(977)
11		11,023

Supporting Schedules: C-37, C-38, C-39

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide a schedule of operation and maintenance expense by function for the test year, the benchmark year and the variance. For each functional benchmark variance, provide the reason(s) for the difference.

Type of Data Shown:
_X_ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
___ Historical Year Ended 12/31/12
Witness: C. J. Erickson

Line No.

A&G

1 Justification

2 1. Pension expense, which is reflected in employee benefits, exceeds the O&M benchmark by $5,871,000. Pension expense has increased because
3 of requirements of the Financial Accounting Standards Board (FASB). The FASB has very specific requirements governing pension accounting,
4 and compliance with these requirements is not discretionary.

5 The primary factor for the increase in pension expenses is the decrease in the required interest rate used to measure benefit obligations, which
6 in this context are typically called liabilities. The FASB requires plan sponsors to measure plan liabilities annually based upon current market
7 interest rates. The qualified and non-qualified pension plans weighted average rate for the test year 2014 is 4.27 percent. The rates used to measure
8 the 2011 and 2012 pension expenses were 5.53 percent and 4.98 percent, respectively. This decline in the required FASB interest rate has increased
9 plan liabilities by $25 million, or 7.6 percent, from year end 2010 to year end 2011 and an additional $39 million, or 10.6 percent, from year end 2011
10 to year end 2012.

11 The secondary factor contributing to the increased expense includes a decrease in the assumed rate of return to reflect a decline in the financial
12 markets. The assumed rates of return (net of investment-related expenses) used to measure 2011 and 2012 pension expense were 8.45% and
13 8.20%, respectively. For the 2014 test year, the assumed rate of return (net of investment-related expenses) is 8.20%. Therefore, we have seen a
14 decrease in the assumed rate of return over the past 4 years (2011-2014) of 25 basis points.

15 These expenses are addressed in more detail in the testimony of Gulf Witness Garvie.

16 2. Property Damage Accrual. In Gulf's last rate case, the Commission approved a storm reserve target range of $48-55 million as the amount
17 necessary to build an adequate reserve to cover most storms. To achieve the storm reserve target of $48-55 million approved in Gulf's most recent
18 rate case, Gulf has proposed an increase in the annual storm reserve accrual from $3,500,000 to $9,000,000. The $9,000,000 annual accrual
19 results in the accrual exceeding the O&M benchmark by $5,249,000. This annual accrual level of $9,000,000 is $2,200,000 higher than the expected
20 average annual loss to be covered by the reserve ($6,800,000) as determined in Gulf's Hurricane Loss and Reserve Performance Analysis.
21 Assuming the balance in the reserve as of March 31, 2013, the average annual losses charged to the reserve of $6,800,000 and the new
22 $9,000,000 annual storm reserve accrual, Gulf's storm reserve would achieve the minimum of the Commission's target range in seven years.
23 The Hurricane Loss and Reserve Performance Analysis is addressed in more detail in the testimony of Gulf Witness Harris; the increase in the
24 annual accrual is addressed in the testimony of Ms. Erickson.

25 3. Gulf's recent rate case experience shows that the cost of a rate case continues to increase due to more discovery, more contested issues and
26 more witnesses as part of a rate case. To address these additional demands, Gulf anticipates incurring more expenses for incremental labor
27 resources, additional outside consulting and legal fees than what was approved in its last rate case after escalation for CPI and customer growth.
28 The rate case benchmark justification is addressed in the testimony of Ms. Erickson.

29 4. N/A

Supporting Schedules: C-37, C-38, C-39

Recap Schedules:

Schedule C-42 | HEDGING COSTS | Page 1 of 1

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide hedging expenses and plant balances by primary account for the test year and the preceding three years. Hedging refers to initiating and/or maintaining a non-speculative financial and/or physical hedging program designed to mitigate fuel and purchased power price volatility for the utility's retail rate payers, exclusive of the costs referenced in Paragraph 3, page 5 of Order No PSC-02-1484-FOF-EI. Show hedging expenses and plant recovered through base rates separate from hedging expenses and plant recovered through the fuel clause.

Type of Data Shown:
X Projected Test Year Ended 12/31/14
X Prior Year Ended 12/31/13
X Historical Year Ended 12/31/11 - 12/31/12
Witness: M. L. Burroughs

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
			2011		2012		2013		2014	
Line No.	Account No.	Account Title	Year Base Rates	Clause	Year Base Rates	Clause	Year Base Rates	Clause	Test Year Base Rates	Clause
1					HEDGING EXPENSE					
2	547	Gas Hedging Support (1)	112,033	-	96,270	-	121,937	-	119,264	-
3					ANNUAL PLANT IN SERVICE					
4		There are no capital investments for hedging.								
5		NOTE: (1) Gas Hedging Support, BWO-4352GH, O&M expenses includes labor, overheads, and expenses of employees engaged in financial								
6		hedging of natural gas.								

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide a schedule of security expenses and security plant balances by primary account and totals for the test year and the preceding three years. Show the security expenses recovered through base rates separate from security expenses recovered through the fuel/capacity clauses. Show the plant balances supporting base rates separate from the plant balances supporting the fuel/capacity clauses. Provide only those security costs incurred after, and as a result of, the terrorist events of September 11, 2001.

Type of Data Shown:

X Projected Test Year Ended 12/31/14
X Prior Year Ended 12/31/13
X Historical Years Ended 12/31/11-12/31/12

Witness: C. J. Erickson, R. J. McMillan

($000's)

(1) Line No.	(2) Account No.	(3) Account Title	(4) 2011 Base Rates	(5) 2011 Clauses	(6) 2012 Base Rates	(7) 2012 Clauses	(8) 2013 Base Rates	(9) 2013 Clauses	(10) 2014 Base Rates	(11) 2014 Clauses
1		EXPENSES								
2	505	Electric Expenses	7	-	-	-	-	-	-	-
3	506	Misc. Steam Power Exps.	560	-	645	-	480	-	488	-
4	935	Maintenance of General Plant	81	-	46	-	86	-	85	-
5		Total Security Expense	648	-	691	-	566	-	573	-
6		ANNUAL PLANT IN SERVICE								
7		CAPITAL								
8	398	Miscellaneous Equipment	1,671	-	1,722	-	1,855	-	2,035	-
9		Total Security Investment	1,671	-	1,722	-	1,855	-	2,035	-

10 Note - Amounts listed above are total security costs, of which all are recovered through base rates.

Supporting Schedules: Recap Schedules:

Schedule C-44 | REVENUE EXPANSION FACTOR | Page 1 of 1

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide the calculation of the revenue expansion factor for the test year.

Type of Data Shown:
X Projected Test Year Ended 12/31/14
_ Prior Year Ended 12/31/13
_ Historical Year Ended 12/31/12
Witness: S. D. Ritenour

(1) Line No.	(2) Description	(3) Percent
1	Revenue Requirement	100.0000
2	Regulatory Assessment Rate	0.0720
3	Bad Debt Rate	0.2934
4	Net Before Income Taxes (1) - (2) - (3)	99.6346
5	State Income Tax Rate	5.5000
6	State Income Tax (4) x (5)	5.4799
7	Net Before Federal Income Tax (4) - (6)	94.1547
8	Federal Income Tax Rate	35.0000
9	Federal Income Tax (7) x (8)	32.9541
10	Revenue Expansion Factor (7) - (9)	61.2006
11	Net Operating Income Multiplier (100% / Line 10)	1.633971

130

Supporting Schedules: C-11

Recap Schedules: A-1

FILED JUL 12, 2013
DOCUMENT NO. 03977-13
FPSC - COMMISSION CLERK

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 130140-EI

GULF POWER

A SOUTHERN COMPANY

MINIMUM FILING REQUIREMENTS

SECTION D – COST OF CAPITAL SCHEDULES

GULF POWER COMPANY

Docket No. 130140-EI
Minimum Filing Requirements

Index

D. Cost of Capital Schedules

Schedules	Witness	Title	Page
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D-2	Teel Ritenour	Cost of Capital – 5 Year History	7
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D-6	Ritenour	Customer Deposits	17
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D-8	Teel Ritenour	Financial Plans – Stocks and Bond Issues	21
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Schedule D-1a | COST OF CAPITAL - 13-MONTH AVERAGE | Page 1 of 3

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide the company's 13-month average cost of capital for the test year, the prior year, and historical base year.

Type of Data Shown:
X Projected Test Year Ended 12/31/14
____ Prior Year Ended 12/31/13
____ Historical Year Ended 12/31/12
Witness: S. D. Ritenour

(1) Line No.	(2) Class of Capital	(3) Company Total Per Books ($000's)	(4) Specific Adjustments ($000's)	(5) Pro Rata Adjustments ($000's)	(6) System Adjusted ($000's)	(7) Jurisdictional Factor %	(8) Jurisdictional Capital Structure ($000's)	(9) Ratio %	(10) Cost Rate %	(11) Weighted Cost Rate %
1	Long-Term Debt	1,281,856	(103,347)	(480,295)	698,214	0.9811104	685,025	36.36	4.96	1.80
2	Short-Term Debt	51,663	(4,154)	(19,362)	28,147	0.9811104	27,615	1.47	0.82	0.01
3	Preference Stock	147,998	(11,941)	(55,449)	80,608	0.9811104	79,085	4.20	6.00	0.25
4	Common Equity	1,332,898	(102,440)	(501,467)	728,991	0.9811104	715,221	37.96	11.50	4.37
5	Customer Deposits	35,350	-	(14,407)	20,943	1.0000000	20,943	1.11	2.30	0.03
6	Deferred Income Taxes	707,553	(53,944)	(266,376)	387,233	0.9811104	379,918	20.17	0.00	0.00
7	FASB 109 Deferred Taxes	(47,899)	3,652	18,033	(26,214)	0.9811104	(25,718)	-1.37	0.00	0.00
8	Investment Credit - Zero Cost	3,492	(375)	(1,270)	1,847	0.9811104	1,812	0.10	8.18	0.01
9	Total	3,512,911	(272,549)	(1,320,593)	1,919,769		1,883,901	100.00		6.47

Supporting Schedules: D-1b, D-3, D-4a, D-5, D-6

Recap Schedules: A-1, B-1

Schedule D-1a | COST OF CAPITAL - 13-MONTH AVERAGE | Page 2 of 3

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide the company's 13-month average cost of capital for the test year, the prior year, and historical base year.

Type of Data Shown:
_____Projected Test Year Ended 12/31/14
_X__Prior Year Ended 12/31/13
_____Historical Year Ended 12/31/12
Witness: S. D. Ritenour

(1) Line No.	(2) Class of Capital	(3) Company Total Per Books ($000's)	(4) Specific Adjustments ($000's)	(5) Pro Rata Adjustments ($000's)	(6) System Adjusted ($000's)	(7) Jurisdictional Factor %	(8) Jurisdictional Capital Structure ($000's)	(9) Ratio %	(10) Cost Rate %	(11) Weighted Cost Rate %
1	Long-Term Debt	1,222,230	(105,055)	(415,112)	702,063	0.9808969	688,651	36.77	4.85	1.78
2	Short-Term Debt	77,666	(8,447)	(26,375)	42,844	0.9808969	42,026	2.24	0.46	0.01
3	Preference Stock	132,613	(11,376)	(45,049)	76,188	0.9808969	74,733	3.99	6.08	0.24
4	Common Equity	1,211,019	(99,775)	(412,908)	698,336	0.9808969	684,996	36.58	11.50	4.21
5	Customer Deposits	34,935	-	(12,981)	21,954	1.0000000	21,954	1.17	2.30	0.03
6	Deferred Income Taxes	671,313	(51,647)	(230,252)	389,414	0.9808969	381,975	20.40	0.00	0.00
7	FASB 109 Deferred Taxes	(42,181)	3,245	14,468	(24,468)	0.9808969	(24,000)	-1.28	0.00	0.00
8	Investment Credit - Zero Cost	4,756	(706)	(1,505)	2,545	0.9808969	2,496	0.13	8.06	0.01
9	Total	3,312,351	(273,761)	(1,129,714)	1,908,876		1,872,831	100.00		6.28

Supporting Schedules: D-1b, D-3, D-4a, D-5, D-6

Recap Schedules: A-1, B-1

Schedule D-1a | COST OF CAPITAL - 13-MONTH AVERAGE | Page 3 of 3

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide the company's 13-month average cost of capital for the test year, the prior year, and historical base year.

Type of Data Shown:
____Projected Test Year Ended 12/31/14
____Prior Year Ended 12/31/13
_X_Historical Year Ended 12/31/12
Witness: S. D. Ritenour

(1) Line No.	(2) Class of Capital	(3) Company Total Per Books ($000's)	(4) Specific Adjustments ($000's)	(5) Pro Rata Adjustments ($000's)	(6) System Adjusted ($000's)	(7) Jurisdictional Factor %	(8) Jurisdictional Capital Structure ($000's)	(9) Ratio %	(10) Cost Rate %	(11) Weighted Cost Rate %
1	Long-Term Debt	1,222,347	(109,377)	(428,140)	684,830	0.9811631	671,930	39.19	4.96	1.94
2	Short-Term Debt	72,767	(8,821)	(25,469)	38,477	0.9811631	37,752	2.20	0.38	0.01
3	Preference Stock	97,998	(8,772)	(34,324)	54,902	0.9811631	53,868	3.14	6.33	0.20
4	Common Equity	1,160,164	(99,619)	(407,972)	652,573	0.9811631	640,281	37.34	11.50	4.29
5	Customer Deposits	35,821	-	(13,780)	22,041	1.0000000	22,041	1.29	4.75	0.06
6	Deferred Income Taxes	554,770	(45,092)	(196,062)	313,616	0.9811631	307,709	17.95	0.00	0.00
7	FASB 109 Deferred Taxes	(39,782)	3,234	14,059	(22,489)	0.9811631	(22,066)	-1.29	0.00	0.00
8	Investment Credit - Zero Cost	6,084	(1,036)	(1,942)	3,106	0.9811631	3,047	0.18	8.08	0.01
9	Total	3,110,169	(269,483)	(1,093,630)	1,747,056		1,714,562	100.00		6.51

Supporting Schedules: D-1b, D-3, D-4a, D-5, D-6

Recap Schedules: A-1, B-1

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: (1) List and describe the basis for the specific adjustments appearing on Schedule D-1a.
(2) List and describe the basis for the pro-rata adjustments appearing on Schedule D-1a.
($000's)

Type of Data Shown:
X Projected Test Year Ended 12/31/14
X Prior Year Ended 12/31/13
X Historical Year Ended 12/31/12
Witness: S. D. Ritenour

(1) Line No.	(2) Class of Capital	(3) Description	(4) Historic Base Year	(5) Prior Year	(6) Test Year
1		Specific Adjustments:			
2	Long-Term Debt	UPS Portion of Long-Term Debt	(109,377)	(105,055)	(103,347)
3		Subtotal Long-Term Debt	(109,377)	(105,055)	(103,347)
4	Short-Term Debt	Clause Under-Recovery Balance	(2,263)	(1,762)	-
5		UPS Portion of Short-Term Debt	(6,558)	(6,685)	(4,154)
6		Subtotal Short Term Debt	(8,821)	(8,447)	(4,154)
7	Preference Stock	UPS Portion of Preference Stock	(8,772)	(11,376)	(11,941)
8		Subtotal Preference Stock	(8,772)	(11,376)	(11,941)
9	Common Equity	Common Dividends Declared	17,815	17,754	18,548
10		Non-Utility Property, Net	(13,218)	(13,050)	(13,029)
11		UPS Portion of Common Equity	(104,216)	(104,479)	(107,959)
12		Subtotal Common Equity	(99,619)	(99,775)	(102,440)
13	Deferred Taxes	UPS Portion of Deferred Taxes	(45,092)	(51,647)	(53,944)
14		Subtotal Deferred Taxes	(45,092)	(51,647)	(53,944)
15	Deferred Taxes (FASB-109)	UPS Portion of Deferred Taxes (FASB-109)	3,234	3,245	3,652
16		Subtotal Deferred Taxes (FASB-109)	3,234	3,245	3,652
17	Investment Credit - Zero Cost	UPS Portion of Investment Tax Credits	(1,036)	(706)	(375)
18		Subtotal Investment Tax Credits - Wtd Cost	(1,036)	(706)	(375)
19		Total Specific Adjustments	(269,483)	(273,761)	(272,549)

Supporting Schedules:

Recap Schedules: D-1a

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: (1) List and describe the basis for the specific adjustments appearing on Schedule D-1a.
(2) List and describe the basis for the pro-rata adjustments appearing on Schedule D-1a.
($000's)

Type of Data Shown:
_X_ Projected Test Year Ended 12/31/14
_X_ Prior Year Ended 12/31/13
_X_ Historical Year Ended 12/31/12
Witness: S. D. Ritenour

(1) Line No.	(2) Class of Capital	(3) Description	(4) Historic Base Year	(5) Prior Year	(6) Test Year
1		Pro Rata Adjustments:			
2		Energy Conservation Cost Recovery Clause Plant (net)	(13,426)	(16,009)	(18,350)
3		Environmental Cost Recovery Clause Plant (net)	(897,404)	(927,689)	(956,635)
4		Interest Bearing CWIP	(156,245)	(160,600)	(312,857)
5		ARO Plant (net)	(15,016)	(19,516)	(19,516)
6		Accumulated Depreciation: 2013 Depreciation Study	-	-	43
7		PHFU - North Escambia	(10,016)	(13,021)	(13,021)
8		ARO Deferred Debit	(5,307)	(5,382)	(5,382)
9		ARO Deferred Credit	14,146	14,326	14,326
10		ARO Liability	11,293	16,055	16,055
11		Loans To Employees & Retirees	(41)	(38)	(38)
12		AEM Inventory (ECCR)	(2,332)	(2,787)	(2,466)
13		Environmental Allowances	(8,373)	(7,653)	(6,783)
14		Interest & Dividends Receivable	(18)	(6)	(25)
15		Accrued Interest on Tax Assessments	131	14	-
16		Deferred North Escambia Site Costs	(8,431)	(5,149)	(5,149)
17		Unamortized 2011 Rate Case Expenses	(2,620)	(1,948)	(1,246)

Supporting Schedules:

Recap Schedules: D-1a

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: (1) List and describe the basis for the specific adjustments appearing on Schedule D-1a.
(2) List and describe the basis for the pro-rata adjustments appearing on Schedule D-1a.
($000's)

Type of Data Shown:
_X_ Projected Test Year Ended 12/31/14
_X_ Prior Year Ended 12/31/13
_X_ Historical Year Ended 12/31/12
Witness: S. D. Ritenour

(1) Line No.	(2) Class of Capital	(3) Description	(4) Historic Base Year	(5) Prior Year	(6) Test Year
1		Pro Rata Adjustments Continued:			
2		Increase in Property Insurance Accrual	-	-	(2,750)
3		Environmental Allowance & Deferred Gain (ECRC)	666	412	204
4		Accumulated Depreciation : Perdido Unit 3	-	-	127
5		Plant in Service : Perdido Unit 3	-	-	(4,460)
6		Environmental Allowance in Deferred Debit	(1,320)	(839)	(624)
7		Plant in Service : Distribution New Business	-	-	(2,068)
8		Accumulated Depreciation : Distribution New Business	-	-	22
9		Accrued Provision for Rate Refund	782	116	-
10		Temporary Cash Investment	(99)	-	-
11		Total Pro Rata Adjustments	(1,093,630)	(1,129,714)	(1,320,593)
12		Total Specific and Pro Rata Adjustments	(1,363,113)	(1,403,475)	(1,593,142)

CONFIDENTIAL

(CONFIDENTIAL) Certain portions of MFR Schedule D-2 filed in connection with petition for rate increase.

Schedule D-2 | COST OF CAPITAL - 5 YEAR HISTORY | Page 1 of 2

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: For the subject Florida utility, all other regulated utility operations combined, all non-regulated operations combined, the parent company, and on a consolidated basis, provide the year-end capital structure for investor capital (i.e. common equity, preferred stock, long-term debt, and short-term debt) for the five years through the end of the projected test year.

Type of Data Shown:
X Projected Test Year Ended 12/31/14
X Prior Year Ended 12/31/13
X Historical Year Ended 12/31/10 - 12/31/12
Witness: R. S. Teel, S. D. Ritenour

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
		2010		2011		2012		2013		2014	
Line No.	Class of Capital	Amount (000's)	Percent of Total	Amount (000's)	Percent of Total	Amount (000's)	Percent of Total	Amount (000's)	Percent of Total	Amount (000's)	Percent of Total
1	Gulf Power Company										
2	Common Stock Equity	1,075,036	43.17	1,124,948	43.72	1,180,742	44.52	1,234,206	44.98	1,349,633	45.00
3	Preference Stock	97,998	3.93	97,998	3.81	97,998	3.70	147,998	5.40	147,998	4.94
4	Long-Term Debt	1,224,398	49.16	1,235,447	48.02	1,245,870	46.99	1,241,457	45.26	1,377,011	45.92
5	Short-Term Debt	93,183	3.74	114,507	4.45	127,002	4.79	119,499	4.36	124,165	4.14
6	Total	2,490,615	100.00	2,572,900	100.00	2,651,612	100.00	2,743,160	100.00	2,998,807	100.00
7	Other Regulated Utility Operations										
8	Common Stock Equity	16,381,551	46.01	17,195,182	46.76	18,359,649	47.40				
9	Preferred (Preference) Stock	983,826	2.76	983,825	2.68	983,825	2.54				
10	Long-Term Debt	15,772,865	44.30	16,149,240	43.93	16,829,477	43.45				
11	Short-Term Debt	2,468,847	6.93	2,436,709	6.63	2,561,780	6.61				
12	Total	35,607,089	100.00	36,764,956	100.00	38,734,731	100.00				
13	Non-Regulated Operations Combined (All other Subsidiaries)										
14	Common Stock Equity	766,637	89.91	750,835	99.55	669,211	99.87				
15	Preference Stock	0	0.00	0	0.00	0	0.00				
16	Long-Term Debt	8,183	0.96	822	0.11	178	0.03				
17	Short-Term Debt	77,834	9.13	2,602	0.34	645	0.10				
18	Total	852,654	100.00	754,259	100.00	670,034	100.00				

[redacted]

Supporting Schedules:

Recap Schedules:

Schedule D-2 | COST OF CAPITAL - 5 YEAR HISTORY | Page 2 of 2

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: For the subject Florida utility, all other regulated utility operations combined, all non-regulated operations combined, the parent company, and on a consolidated basis, provide the year-end capital structure for investor capital (i.e. common equity, preferred stock, long-term debt, and short-term debt) for the five years through the end of the projected test year.

Type of Data Shown:
X Projected Test Year Ended 12/31/14
X Prior Year Ended 12/31/13
X Historical Year Ended 12/31/10 - 12/31/12
Witness: R. S. Teel, S. D. Ritenour

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
		2010		2011		2012		2013		2014	
Line No.	Class of Capital	Amount (000's)	Percent of Total	Amount (000's)	Percent of Total	Amount (000's)	Percent of Total	Amount (000's)	Percent of Total	Amount (000's)	Percent of Total
1	Parent Company										
2	Common Stock Equity	16,283,075	89.44	17,702,542	90.95	18,438,428	90.93				
3	Preference Stock	0	0.00	0	0.00	0	0.00				
4	Long-Term Debt	1,258,853	6.91	1,761,967	9.05	1,258,867	6.21				
5	Short-Term Debt	664,809	3.65	0	0.00	580,152	2.86				
6	Total	18,206,737	100.00	19,464,509	100.00	20,277,447	100.00				
7	Eliminations										
8	Common Stock Equity	(18,304,451)	95.73	(19,196,019)	97.57	(20,351,074)	99.18				
9	Preference Stock	0	0.00	0	0.00	0	0.00				
10	Long-Term Debt	0	0.00	0	0.00	0	0.00				
11	Short-Term Debt	(816,982)	4.27	(477,671)	2.43	(168,859)	0.82				
12	Total	(19,121,433)	100.00	(19,673,690)	100.00	(20,519,933)	100.00				
13	Consolidated Basis										
14	Common Stock Equity	16,201,848	42.60	17,577,488	44.07	18,296,956	43.75				
15	Preference Stock	1,081,824	2.84	1,081,823	2.71	1,081,823	2.59				
16	Long-Term Debt	18,264,299	48.02	19,147,476	48.01	19,334,392	46.24				
17	Short-Term Debt	2,487,691	6.54	2,076,147	5.21	3,100,720	7.42				
18	Total	38,035,662	100.00	39,882,934	100.00	41,813,891	100.00				

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: (1) Provide the specified data on short-term debt issues on a 13-month average basis for the test year, prior year, and historical base year.

(2) Provide a narrative description of the Company's policies regarding short-term financing. The following topics should be covered: ratio of short-term debt to total capital, plant expansion, working capital, timing of long-term financing, method of short-term financing (bank loans, commercial paper, etc.) and other uses of short-term financing.

Type of Data Shown:
X Projected Test Year Ended 12/31/14
X Prior Year Ended 12/31/13
X Historical Year Ended 12/31/12
Witness: S. D. Ritenour, R. S. Teel

(1) Line No.	(2) Maturity Date	(3) Interest Rate	(4) Interest Expense	(5) 13-Month Average Amount Outstanding During the Year ($000's)	(6) Weighted Avg. Cost of Short-Term Debt
1	2012				
2	Various Dates	Various	276	72,767	0.38%
3	2013				
4	Various Dates	Various	359	77,666	0.46%
5	2014				
6	Various Dates	Various	423	51,663	0.82%

7 In determining the appropriate level of short-term debt to include in its capital structure, Gulf attempts to achieve the most cost-effective balance between interest rates and
8 liquidity. During the test year, Gulf's short-term debt as a percent of total capitalization (debt, preferred and common equity) is 1.8%. Most of the short-term borrowing is in the
9 form of commercial paper. Gulf has bank lines of credit totaling $275 million to support its commercial paper program, daily rate pollution control bonds and other borrowing
10 needs. Short-term debt is used for the ongoing operating needs of the Company, rather than being related to a specific project. Gulf's policy reflects the inclusion of some
11 short-term debt. The amount varies due to a number of factors including seasonality. The timing of long-term financing is dependent on several factors, including market conditions,
12 projected levels of short-term debt and projected capital needs.

Schedule D-4a | LONG-TERM DEBT OUTSTANDING | Page 1 of 3

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide the specified data on long-term debt issues on a 13-month average basis for the test year, prior year, and historical base year. Arrange by type of issue (i.e., first mortgage bonds).

($000's)

Type of Data Shown:
X Projected Test Year Ended 12/31/14
_ Prior Year Ended 12/31/13
_ Historical Year Ended 12/31/12
Witness: S. D. Ritenour

Thirteen Month Average Long-Term Debt for the Test Year Ended 12/31/14

(1) Line No.	(2) Description, Coupon Rate	(3) Issue Date	(4) Maturity Date	(5) Principal Amount Sold- (Face Value)	(6) 13-Month Average Principal Amount Outstanding	(7) Discount (Premium) on Principal Amt. Sold	(8) Issuing Expense on Principal Amt Sold	(9) Life (Years)	(10) Annual Amortization (7 + 8) / 9	(11) Interest Expense (Coupon Rate) (2) X (6)	(12) Total Annual Cost (10) + (11)	(13) Unamortized Discount (Premium) Assoc. with (6)	(14) Unamort. Issuing Expense & Loss on Reacquired Debt Assoc. with (6)
	Senior Notes and Other Long Term Debt												
1	5.75% Senior Note	5/18/2011	6/1/2051	125,000	125,000	3,938	103	40	101	7,188	7,289	3,631	181
2	3.10% Senior Note	5/18/2012	5/15/2022	100,000	100,000	837	83	10	92	3,100	3,192	660	70
3	4.75% Senior Note	6/1/2013	5/1/2043	55,000	55,000	0	0	30	0	2,613	2,613	0	0
4	4.90% Senior Note	9/22/2004	10/1/2014	75,000	57,692	488	228	10	71	2,827	2,898	15	5
5	5.10% Senior Note	9/17/2010	10/1/2040	125,000	125,000	1,094	182	30	43	6,375	6,418	1,026	91
6	5.25% Senior Note (a)	7/22/2003	7/15/2033	60,000	30,000	1,890	(330)	30	52	1,575	1,627	600	391
7	5.65% Senior Note	8/30/2005	9/1/2035	60,000	60,000	525	459	30	33	3,390	3,423	188	504
8	5.85% Senior Note	4/1/2014	3/1/2044	70,000	48,462	0	0	30	0	2,835	2,835	0	0
9	6.25% Senior Note	10/1/2014	9/1/2044	140,000	32,308	0	0	30	0	2,019	2,019	0	0
10	4.75% Senior Note	4/13/2010	4/15/2020	175,000	175,000	1,137	(1,327)	10	(19)	8,313	8,294	674	(785)
11	5.30% Senior Note	12/6/2006	12/1/2016	110,000	110,000	715	5,672	10	639	5,830	6,469	179	1,372
12	5.90% Senior Note	6/12/2007	6/15/2017	85,000	85,000	552	(2,787)	10	(223)	5,015	4,792	176	(829)
	Pollution Control Bonds												
13	4.725% PCB (b)	11/20/2012	11/1/2042	13,000	13,000	33	174	30	7	614	621	0	676
14	5.25% PCB	9/26/2002	9/1/2037	42,000	42,000	147	1,899	35	58	2,205	2,263	0	1,355
15	5.625% PCB	10/9/2002	7/1/2022	37,000	37,000	81	1,204	20	64	2,081	2,145	0	514
16	6.0% PCB	4/15/2003	2/1/2026	29,075	29,075	102	1,598	23	74	1,745	1,819	0	863
17	VAR% PCB	7/1/1997	7/1/2022	3,930	3,930	9	45	25	2	34	36	3	14
18	VAR% PCB	3/31/2009	4/1/2039	65,400	65,400	245	1,073	30	44	573	617	0	1,091
19	1.55% PCB	4/15/2003	6/1/2023	32,550	32,550	114	1,388	20	75	505	580	0	671
20	1.35% PCB	3/31/2009	4/1/2039	65,000	65,000	244	406	30	21	878	899	0	519
21	4.275% PCB (c)	6/3/2010	6/1/2049	21,000	21,000	74	472	39	14	898	912	65	291
22	Unamortized Loss on Reacq. Debt								1,837	0	1,837	0	16,350
23	Total				1,312,417	12,225	10,542	522	2,985	60,613	63,598	7,217	23,344
24	Less: Unamortized Premium, Discount, and												
25	Issuance Expense (13) + (14)				30,561								
26													
27	Net				1,281,856								
28	Embedded Cost of Long-Term Debt												
29	(12) / Net				4.96%								

(a) $30M redeemed in 6/2012
(b) Rate effective beginning 11/2013. Previous rate was .55%
(c) Rate effective beginning 6/3/2013. Previous rate was 2.125%

Supporting Schedules:

Recap Schedules: D-1a

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FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide the specified data on long-term debt issues on a 13-month average basis for the test year, prior year, and historical base year. Arrange by type of issue (i.e., first mortgage bonds).

($000's)

Type of Data Shown:
_ Projected Test Year Ended 12/31/14
X Prior Year Ended 12/31/13
_ Historical Year Ended 12/31/12
Witness: S. D. Ritenour

Thirteen Month Average Long-Term Debt for the Prior Year Ended 12/31/13

(1) Line No.	(2) Description, Coupon Rate	(3) Issue Date	(4) Maturity Date	(5) Principal Amount Sold- (Face Value)	(6) 13-Month Average Principal Amount Outstanding	(7) Discount (Premium) on Principal Amt. Sold	(8) Issuing Expense on Principal Amt Sold	(9) Life (Years)	(10) Annual Amortization (7 + 8) / 9	(11) Interest Expense (Coupon Rate) (2) X (6)	(12) Total Annual Cost (10) + (11)	(13) Unamortized Discount (Premium) Assoc. with (6)	(14) Unamort. Issuing Expense & Loss on Reacquired Debt Assoc. with (6)
	Senior Notes and Other Long Term Debt												
1	5.75% Senior Note	5/18/2011	6/1/2051	125,000	125,000	3,938	103	40	101	7,188	7,289	3,729	186
2	3.10% Senior Note	5/18/2012	5/15/2022	100,000	100,000	837	83	10	92	3,100	3,192	743	79
3	4.75% Senior Note	6/1/2013	5/1/2043	55,000	29,615	0	0	30	0	1,407	1,407	0	0
4	4.90% Senior Note	9/22/2004	10/1/2014	75,000	75,000	488	228	10	71	3,675	3,746	66	23
5	5.10% Senior Note	9/17/2010	10/1/2040	125,000	125,000	1,094	182	30	43	6,375	6,418	1,065	94
6	5.25% Senior Note (a)	7/22/2003	7/15/2033	60,000	30,000	1,890	(330)	30	52	1,575	1,627	632	412
7	5.65% Senior Note	8/30/2005	9/1/2035	60,000	60,000	525	459	30	33	3,390	3,423	197	528
8	4.35% Senior Note	7/22/2003	7/15/2013	60,000	32,308	390	1,898	10	123	1,688	1,811	7	48
9	4.75% Senior Note	4/13/2010	4/15/2020	175,000	175,000	1,137	(1,327)	10	(19)	8,313	8,294	790	(921)
10	5.30% Senior Note	12/6/2006	12/1/2016	110,000	110,000	715	5,672	10	639	5,830	6,469	253	1,936
11	5.90% Senior Note	6/12/2007	6/15/2017	85,000	85,000	552	(2,787)	10	(223)	5,015	4,792	235	(1,111)
	Pollution Control Bonds												
12	.55% PCB (b)	11/20/2012	11/1/2042	13,000	13,000	33	174	30	7	113	120	0	717
13	5.25% PCB	9/26/2002	9/1/2037	42,000	42,000	147	1,899	35	58	2,205	2,263	0	1,413
14	5.625% PCB	10/9/2002	7/1/2022	37,000	37,000	81	1,204	20	64	2,081	2,145	0	578
15	6.0% PCB	4/15/2003	2/1/2026	29,075	29,075	102	1,598	23	74	1,745	1,819	0	937
16	VAR% PCB	7/1/1997	7/1/2022	3,930	3,930	9	45	25	2	23	25	3	16
17	VAR% PCB	3/31/2009	4/1/2039	65,400	65,400	245	1,073	30	44	362	406	0	1,135
18	1.55% PCB	4/15/2003	6/1/2023	32,550	32,550	114	1,388	20	75	505	580	0	746
19	1.35% PCB	3/31/2009	4/1/2039	65,000	65,000	244	406	30	21	878	899	0	540
20	2.125% PCB (c)	6/3/2010	6/1/2049	21,000	21,000	74	433	39	13	691	704	67	302
21	Unamortized Loss on Reacq. Debt								1,874	0	1,874	0	18,203
22	Total				1,255,878	12,615	12,401	472	3,144	56,159	59,303	7,787	25,861
23	Less: Unamortized Premium, Discount, and												
24	Issuance Expense (13) + (14)				33,648								
25	Net				1,222,230								
26	Embedded Cost of Long-Term Debt												
27	(12) / Net				4.85%								

(a) $30M redeemed in 6/2012
(b) Rate effective through 11/2013. Rate of 4.725% thereafter
(c) Rate effective through 6/3/2013. Rate of 4.275% thereafter

Supporting Schedules:

Recap Schedules: D-1a

Schedule D-4a | LONG-TERM DEBT OUTSTANDING | Page 3 of 3

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide the specified data on long-term debt issues on a 13-month average basis for the test year, prior year, and historical base year. Arrange by type of issue (i.e., first mortgage bonds).

($000's)

Type of Data Shown:
_ Projected Test Year Ended 12/31/14
_ Prior Year Ended 12/31/13
X Historical Year Ended 12/31/12
Witness: S. D. Ritenour

Thirteen Month Average Long-Term Debt for the Historical Year Ended 12/31/12

(1) Line No.	(2) Description, Coupon Rate	(3) Issue Date	(4) Maturity Date	(5) Principal Amount Sold- (Face Value)	(6) 13-Month Average Principal Amount Outstanding	(7) Discount (Premium) on Principal Amt. Sold	(8) Issuing Expense on Principal Amt. Sold	(9) Life (Years)	(10) Annual Amortization (7 + 8) / 9	(11) Interest Expense (Coupon Rate) (2) X (6)	(12) Total Annual Cost (10) + (11)	(13) Unamortized Discount (Premium) Assoc. with (6)	(14) Unamort. Issuing Expense & Loss on Reacquired Debt Assoc. with (6)
	Senior Notes and Other Long Term Debt												
1	5.75% Senior Note	5/18/2011	6/1/2051	125,000	125,000	3,938	103	40	101	7,188	7,289	3,827	189
2	3.10% Senior Note	5/18/2012	5/15/2022	100,000	61,538	837	83	10	92	1,788	1,880	498	48
3	4.90% Senior Note	9/22/2004	10/1/2014	75,000	75,000	488	228	10	71	3,675	3,746	119	41
4	5.10% Senior Note	9/17/2010	10/1/2040	125,000	125,000	1,094	182	30	43	6,375	6,418	1,104	98
5	5.25% Senior Note (a)	7/22/2003	7/15/2033	60,000	43,847	1,890	1,239	30	104	2,379	2,483	974	635
6	5.60% Senior Note (b)	3/26/2003	4/1/2033	65,000	28,316	2,048	(1,062)	9	110	1,750	1,860	625	409
7	5.65% Senior Note	8/30/2005	9/1/2035	60,000	60,000	525	459	30	33	3,390	3,423	206	552
8	4.35% Senior Note	7/22/2003	7/15/2013	60,000	60,000	390	3,531	10	392	2,610	3,002	39	352
9	4.75% Senior Note	4/13/2010	4/15/2020	175,000	175,000	1,137	(1,327)	10	(19)	8,313	8,294	907	(1,057)
10	5.30% Senior Note	12/6/2006	12/1/2016	110,000	110,000	715	5,672	10	639	5,830	6,469	328	2,501
11	5.90% Senior Note	6/12/2007	6/15/2017	85,000	85,000	552	(2,787)	10	(223)	5,015	4,792	294	(1,393)
	Pollution Control Bonds												
12	.55% PCB (c)	11/20/2012	11/1/2042	13,000	2,000	33	174	30	7	8	15	0	27
13	4.8% PCB (d)	9/26/2002	9/1/2028	13,000	12,000	390	631	30	34	624	658	0	550
14	5.25% PCB	9/26/2002	9/1/2037	42,000	42,000	147	1,899	35	58	2,205	2,263	0	1,472
15	5.625% PCB	10/9/2002	7/1/2022	37,000	37,000	81	1,204	20	64	2,081	2,145	0	643
16	6.0% PCB	4/15/2003	2/1/2026	29,075	29,075	102	1,598	23	74	1,745	1,819	0	1,012
17	VAR% PCB	7/1/1997	7/1/2022	3,930	3,930	9	45	25	2	9	11	4	18
18	VAR% PCB	3/31/2009	4/1/2039	65,400	65,400	245	1,073	30	44	117	161	0	1,079
19	1.55% PCB (e)	4/15/2003	6/1/2023	32,550	32,550	114	1,388	20	75	537	612	0	707
20	1.35% PCB (f)	3/31/2009	4/1/2039	65,000	65,000	244	406	30	21	1,010	1,031	0	561
21	2.125% PCB (g)	6/3/2010	6/1/2049	21,000	21,000	74	325	39	10	446	456	70	312
22	Unamortized Loss on Reacq. Debt								1,791	0	1,791	0	18,558
23	Total				1,258,656	15,053	15,064	481	3,523	57,095	60,618	8,995	27,314
24	Less: Unamortized Premium, Discount, and												
25	Issuance Expense (13) + (14)				36,309								
26													
27	Net				1,222,347								
28													
29	Embedded Cost of Long-Term Debt												
30	(12) / Net				4.96%								

(a) $30M redeemed in 6/2012
(b) Redeemed 6/2012
(c) Rate effective through 11/2013. Rate of 4.725% thereafter
(d) Redeemed 12/2012
(e) Rate effective beginning 6/2012. Previous rate was 1.75%
(f) Rate effective beginning 4/2012. Previous rate was 2.0%
(g) Rate effective through 6/3/2013. Rate of 4.275% thereafter

Supporting Schedules:

Recap Schedules: D-1a

Schedule D-4b	REACQUIRED BONDS	Page 1 of 1
FLORIDA PUBLIC SERVICE COMMISSION	EXPLANATION: Supply a statement of the company's policy on treatment of profit or loss from reacquired bonds. Detail any profit or loss on reacquired bonds for the test year and prior year.	Type of Data Shown: _X_ Projected Test Year Ended 12/31/14 _X_ Prior Year Ended 12/31/13 ___ Historical Year Ended 12/31/12
COMPANY: GULF POWER COMPANY		Witness: S. D. Ritenour
DOCKET NO.: 130140-EI		

(1) Line No.	(2)
1	Gulf Power Company treats profits or losses on reacquired bonds in accordance with the Code of Federal Regulations: Title 18;
2	Conservation of Power and Water Resources, Part 101; General Instructions, paragraph 17. The test year and prior year do not
3	include any projected reacquired bonds.

Supporting Schedules:

Recap Schedules:

Schedule D-5 | PREFERRED STOCK OUTSTANDING | Page 1 of 3

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide the data as specified for preferred stock on a 13-month average basis for the test year, prior year and historical base year.

($000's)

Type of Data Shown:
X Projected Test Year Ended 12/31/14
_ Prior Year Ended 12/31/13
_ Historical Year Ended 12/31/12
Witness: S. D. Ritenour

Thirteen-Month Average Preference Stock for the Test Year Ended 12/31/14

(1) Line No.	(2) Description, Coupon Rate	(3) Issue Date	(4) Call Provisions or Special Restrictions	(5) Principal Amount Sold	(6) 13-Month Avg. Principal Amount Outstanding	(7) (Discount) Premium on Principal Amount Sold	(8) (Discount) Premium Associated with (6)	(9) Issuing Expense on Principal Amount Sold	(10) Issuing Expense Associated with (6)	(11) Net Proceeds (6)+(8)-(10)	(12) Dollar Dividend on Face Value (2) x (6)	(13) Effective Cost Rate (12) / (11)
1	6.00%	11-15-05	Note 1	55,000	55,000	0	0	1,114	1,114	53,886	3,300	6.12%
2	6.45%	10-19-07	Note 2	45,000	45,000	0	0	888	888	44,112	2,903	6.58%
3	5.36%	04-01-13		50,000	50,000	0	0	0	0	50,000	2,680	5.36%
4	Total			150,000	150,000	0	0	2,002	2,002	147,998	8,883	6.00%
5	Weighted Average Cost of Preferred Stock											6.00%

Note 1: The Company shall have the right to redeem Preference Stock, without premium, from time to time, on or after November 15, 2010, upon notice, at a redemption price equal to $100.00 per share plus accrued and unpaid dividends.

Note 2: The Company shall have the right to redeem the Preference Stock, from time to time, per the calculation outlined in the prospectus dated November 20, 2006.

Supporting Schedules:

Recap Schedules: D-1a

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide the data as specified for preferred stock on a 13-month average basis for the test year, prior year and historical base year.

($000's)

Type of Data Shown:
_ Projected Test Year Ended 12/31/14
X Prior Year Ended 12/31/13
_ Historical Year Ended 12/31/12
Witness: S. D. Ritenour

Thirteen-Month Average Preference Stock for the Prior Year Ended 12/31/13

(1) Line No.	(2) Description, Coupon Rate	(3) Issue Date	(4) Call Provisions or Special Restrictions	(5) Principal Amount Sold	(6) 13-Month Avg. Principal Amount Outstanding	(7) (Discount) Premium on Principal Amount Sold	(8) (Discount) Premium Associated with (6)	(9) Issuing Expense on Principal Amount Sold	(10) Issuing Expense Associated with (6)	(11) Net Proceeds (6)+(8)-(10)	(12) Dollar Dividend on Face Value (2) x (6)	(13) Effective Cost Rate (12) / (11)
1	6.00%	11-15-05	Note 1	55,000	55,000	0	0	1,114	1,114	53,886	3,300	6.12%
2	6.45%	10-19-07	Note 2	45,000	45,000	0	0	888	888	44,112	2,903	6.58%
3	5.36%	04-01-13		50,000	34,615	0	0	0	0	34,615	1,855	5.36%
4	Total			150,000	134,615	0	0	2,002	2,002	132,613	8,058	6.08%
5	Weighted Average Cost of Preferred Stock											6.08%

Note 1: The Company shall have the right to redeem Preference Stock, without premium, from time to time, on or after November 15, 2010, upon notice, at a redemption price equal to $100.00 per share plus accrued and unpaid dividends.

Note 2: The Company shall have the right to redeem the Preference Stock, from time to time, per the calculation outlined in the prospectus dated November 20, 2006.

Supporting Schedules:

Recap Schedules: D-1a

Schedule D-5 | PREFERRED STOCK OUTSTANDING | Page 3 of 3

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide the data as specified for preferred stock on a 13-month average basis for the test year, prior year and historical base year.

($000's)

Type of Data Shown:
_ Projected Test Year Ended 12/31/14
_ Prior Year Ended 12/31/13
X Historical Year Ended 12/31/12
Witness: S. D. Ritenour

Thirteen-Month Average Preference Stock for the Prior Year Ended 12/31/12

(1) Line No.	(2) Description, Coupon Rate	(3) Issue Date	(4) Call Provisions or Special Restrictions	(5) Principal Amount Sold	(6) 13-Month Avg. Principal Amount Outstanding	(7) (Discount) Premium on Principal Amount Sold	(8) (Discount) Premium Associated with (6)	(9) Issuing Expense on Principal Amount Sold	(10) Issuing Expense Associated with (6)	(11) Net Proceeds (6)+(8)-(10)	(12) Dollar Dividend on Face Value (2) x (6)	(13) Effective Cost Rate (12) / (11)
1	6.00%	11-15-05	Note 1	55,000	55,000	0	0	1,114	1,114	53,886	3,300	6.12%
2	6.45%	10-19-07	Note 2	45,000	45,000	0	0	888	888	44,112	2,903	6.58%
3	Total			100,000	100,000	0	0	2,002	2,002	97,998	6,203	6.33%
4	Weighted Average Cost of Preferred Stock											6.33%

5 Note 1: The Company shall have the right to redeem Preference Stock, without premium, from time to time, on or after November 15, 2010, upon
6 notice, at a redemption price equal to $100.00 per share plus accrued and unpaid dividends.

7 Note 2: The Company shall have the right to redeem the Preference Stock, from time to time, per the calculation outlined in the prospectus
8 dated November 20, 2006.

Supporting Schedules:

Recap Schedules: D-1a

Schedule D-6 | CUSTOMER DEPOSITS | Page 1 of 3

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide monthly balances, interest rates, and interest payments on customer deposits for the test year, the prior year and historical base year.

Type of Data Shown:
X Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
___ Historical Year Ended 12/31/12
Witness: S. D. Ritenour

(1) Line No.	(2) Month and Year	(3) Active Customer Deposits @ 2% & 3% ($000's)	(4) Inactive Customer Deposits ($000's)	(5) Total Deposits (3)+(4) ($000's)	(6) Total Interest Payments @ 2% & 3% ($000's)	(7) Actual Payments & Credits on Bills ($000's)
1	December-13	35,075	0	35,075	67	0
2	January-14	35,136	0	35,136	67	0
3	February-14	35,191	0	35,191	67	0
4	March-14	35,239	0	35,239	68	0
5	April-14	35,286	0	35,286	68	0
6	May-14	35,334	0	35,334	68	0
7	June-14	35,396	0	35,396	68	808
8	July-14	35,441	0	35,441	68	0
9	August-14	35,476	0	35,476	68	0
10	September-14	35,477	0	35,477	68	0
11	October-14	35,482	0	35,482	68	0
12	November-14	35,498	0	35,498	68	0
13	December-14	35,519	0	35,519	68	0
14	13 Month Average	35,350	0	35,350		
15	12 Month Total				814	
16	Effective Interest Rate					
17	12 Month Interest					
18	Expense (6) divided by					
19	Total Deposits (5)		2.30%			

Column (4) Note: Gulf does not maintain deposits on inactive accounts.

Supporting Schedules:

Recap Schedules: D-1a

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Schedule D-6 | CUSTOMER DEPOSITS | Page 2 of 3

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide monthly balances, interest rates, and interest payments on customer deposits for the test year, the prior year and historical base year.

Type of Data Shown:
___ Projected Test Year Ended 12/31/14
X Prior Year Ended 12/31/13
___ Historical Year Ended 12/31/12
Witness: S. D. Ritenour

(1) Line No.	(2) Month and Year	(3) Active Customer Deposits @ 2% & 3% ($000's)	(4) Inactive Customer Deposits ($000's)	(5) Total Deposits (3)+(4) ($000's)	(6) Total Interest Payments @ 2% & 3% ($000's)	(7) Actual Payments & Credits on Bills ($000's)
1	December-12	34,749	0	34,749	61	0
2	January-13	34,749	0	34,749	67	0
3	February-13	34,784	0	34,784	67	0
4	March-13	34,822	0	34,822	67	0
5	April-13	34,869	0	34,869	67	0
6	May-13	34,911	0	34,911	67	0
7	June-13	34,978	0	34,978	67	1,100
8	July-13	35,016	0	35,016	67	0
9	August-13	35,050	0	35,050	67	0
10	September-13	35,049	0	35,049	67	0
11	October-13	35,050	0	35,050	67	0
12	November-13	35,054	0	35,054	67	0
13	December-13	35,075	0	35,075	67	0
14	13 Month Average	34,935	0	34,935		
15	12 Month Total				804	
16	Effective Interest Rate					
17	12 Month Interest					
18	Expense (6) divided by					
19	Total Deposits (5)		2.30%			

Column (4) Note: Gulf does not maintain deposits on inactive accounts.

Supporting Schedules: | Recap Schedules: D-1a

Schedule D-6 | CUSTOMER DEPOSITS | Page 3 of 3

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide monthly balances, interest rates, and interest payments on customer deposits for the test year, the prior year and historical base year.

Type of Data Shown:
___ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
X Historical Year Ended 12/31/12
Witness: S. D. Ritenour

(1) Line No.	(2) Month and Year	(3) Active Customer Deposits* ($000's)	(4) Inactive Customer Deposits ($000's)	(5) Total Deposits (3)+(4) ($000's)	(6) Total Interest Payments* ($000's)	(7) Actual Payments & Credits on Bills ($000's)
1	December-11	35,779	0	35,779	186	774
2	January-12	35,689	0	35,689	192	790
3	February-12	35,813	0	35,813	153	792
4	March-12	36,010	0	36,010	203	802
5	April-12	36,118	0	36,118	196	755
6	May-12	36,094	0	36,094	191	971
7	June-12	36,028	0	36,028	189	2,701
8	July-12	36,041	0	36,041	193	743
9	August-12	35,973	0	35,973	87	756
10	September-12	35,849	0	35,849	88	813
11	October-12	35,801	0	35,801	75	744
12	November-12	35,735	0	35,735	74	698
13	December-12	34,749	0	34,749	61	1,686
14	13 Month Average	35,821	0	35,821		
15	12 Month Total				1,702	
16	Effective Interest Rate					
17	12 Month Interest					
18	Expense (6) divided by					
19	Total Deposits (5)		4.75%			

* Note: Customer deposits accrued interest at 6% and 7% through July 2012. Pursuant to FPSC Order No. PSC-12-0266-NOR-PU the current rates are 2% and 3%.
Column (4) Note: Gulf does not maintain deposits on inactive accounts.

Supporting Schedules: | Recap Schedules: D-1a

Schedule D-7 | COMMON STOCK DATA | Page 1 of 1

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide the most recent five year data for the company, or consolidated parent if the company is not publicly traded as indicated. To the extent the requested data is available from other sources, the Company can reference and attach the information to comply with the requirements of this MFR.

Type of Data Shown:
___ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
_X_ Historical Year Ended 12/31/08 - 12/31/12
Witness: R. S. Teel, S. D. Ritenour

(1) Line No.	(2) Description	(3) 2008	(4) 2009	(5) 2010	(6) 2011	(7) 2012
1	Pre-tax Interest Coverage Ratio (X)	4.37	4.56	4.64	3.78	4.37
2	Earned Returns on Average Book Equity (%)	12.66	12.18	11.69	9.55	10.92
3	Book Value/Share ($)	17.08	18.15	19.21	20.32	21.09
4	Dividends/Share ($)	1.66	1.73	1.80	1.87	1.94
5	Earnings/Share ($)	2.26	2.07	2.37	2.57	2.70
6	Market Value/Share ($)	37.00	33.32	38.23	46.29	42.81
7	Market/Book Ratio (%)	216.60	183.60	199.00	227.80	203.00
8	Price/Earning Ratio (6) / (5)	16.40	16.10	16.10	18.00	15.90

Supporting Schedules:

Recap Schedules:

Schedule D-8 | FINANCIAL PLANS - STOCKS AND BOND ISSUES | Page 1 of 1

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: 1.) If the test year is projected, provide a summary of financing plans and assumptions.

2.) Provide the company's capital structure objectives, the basis for assumptions (such as those for issue cost and interest rates), and any other significant assumptions. Provide a statement of the Company's policy on the timing of the entrance into capital markets.

Type of Data Shown:
X Projected Test Year Ended 12/31/14
__ Prior Year Ended 12/31/13
__ Historical Year Ended 12/31/12
Witness: R. S. Teel, S. D. Ritenour

Financing Plans for the Year Ended 12/31/14

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
				For Bonds		For Stock			
Line No.	Type of Issue	Date of Issue/ Retirement	Capitalization ($000's)	Interest Rate	Life in Years	No. of Shares	Market Price	Issue Costs ($000's)	Principal Amount ($000's)
1	Senior Unsecured Notes	4/1/2014	70,000	5.85%	30				
2		10/1/2014	140,000	6.25%	30				
3	Pollution Control Bonds		NONE PROJECTED FOR PERIOD						
4	Preference Stock		NONE PROJECTED FOR PERIOD						
5	Capital Contributions	1/1/2014	120,798						120,798

6 Capital Structure Objectives:
7 Gulf's objective is to maintain a balanced capital structure that will provide the utility with the financial flexibility and strength to attract the capital necessary to provide reliable
8 electric service to its customers. Gulf's long-term financing plans, which include equity contributions from Southern Company, are designed to support a strong credit profile
9 to meet the heavy capital requirements that are needed. Gulf focuses on maintaining its A credit rating. Gulf's current forecast supports a debt/preferred/equity ratio of 50%/5%/45%.

10 Interest Rate Assumptions (Senior Note):	1Q14	2Q14	3Q14	4Q14
11	5.50%	5.85%	6.00%	6.25%

12 Interest rate assumptions are provided by Southern Company Services, Inc. based upon a market forecast by Moody's Analytics. The 30 year Treasury rates as forecasted by
13 Moody's Analytics are used as the basis for the interest rate assumptions. A risk premium of 150 basis points is added to the 30 year Treasury rates to arrive
14 at interest rates consistent with Gulf's "A" debt rating. Short-term rates are based on the Moody's Analytics forecast for 3 month LIBOR (London InterBank Offered Rate).
15 The interest rates developed consider the effect of debt related costs over the life of the debt issue. All issues are assumed to be sold at face value.

16 Company's Policy on the Timing of Entrance into Capital Markets:
17 The Company continuously monitors capital market conditions for opportunities to minimize its overall cost of capital. Each year a financing plan is developed based on current year debt
18 maturities, captial expenditure projections and forecasted internally generated funds. Gulf's participation in the commercial paper program through Southern Company Funding Corp.
19 and its existing committed credit facilities provide sufficient liquidity and flexibility in determining the amount and timing of long-term debt issuances. With a goal of maintaining financial
20 flexibility and liquidity, the timing of the Company's entrance into the capital markets is based on actual and projected short-term debt balances and capital market conditions.

Supporting Schedules: | Recap Schedules:

Schedule D-9 | FINANCIAL INDICATORS - SUMMARY | Page 1 of 1

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide financial indicators for the test year under current and proposed rates, the prior year, and historical base year.

Type of Data Shown:
_X_ Projected Test Year Ended 12/31/14
_X_ Prior Year Ended 12/31/13
_X_ Historical Year Ended 12/31/12
Witness: R. S. Teel, S. D. Ritenour

(1) Line No.	(2) Indicator	(3) Historic Base 2012	(4) Prior 2013	(5) Test Year Current Rates	(6) Test Year Proposed Rates
1	Interest Coverage Ratios:				
2	Including AFUDC in Income Before Interest Charges	4.37	4.35	3.80	4.94
3	Excluding AFUDC in Income Before Interest Charges	4.25	4.18	3.51	4.65
4	AFUDC as a percent of Income Available for Common	5.36%	7.27%	15.37%	10.79%
5	Percent of Construction Funds Generated Internally	80.51%	73.04%	41.64%	51.60%
6	Fixed Charges:				
7	Interest (Before Deducting AFUDC)	62,749	60,499	65,172	65,172
8	Lease Payments	0	0	0	0
9	Sinking Funds Payments	0	0	0	0
10	Tax of Sinking Fund Payments	0	0	0	0
11	Total Fixed Charges	62,749	60,499	65,172	65,172
12	Ratio of Earnings to Fixed Charges				
13	Including AFUDC	4.37	4.35	3.80	4.94
14	Excluding AFUDC	4.25	4.18	3.51	4.65

Supporting Schedules:

Recap Schedules:

FILED JUL 12, 2013
DOCUMENT NO. 03978-13
FPSC - COMMISSION CLERK

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 130140-EI

GULF POWER

A SOUTHERN COMPANY

MINIMUM FILING REQUIREMENTS

SECTION E – COST OF SERVICE AND RATE DESIGN SCHEDULES
VOLUME ONE

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 130140-EI

GULF POWER

A SOUTHERN COMPANY

MINIMUM FILING REQUIREMENTS

SECTION E – COST OF SERVICE AND RATE DESIGN SCHEDULES

VOLUME ONE

GULF POWER COMPANY

Docket No. 130140-EI
Minimum Filing Requirements

Index

E. Cost of Service and Rate Design Schedules
Volume One

Schedules	Witness	Title	Page
E-1	O'Sheasy	Cost of Service Studies	1

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide under separate cover a cost of service study that allocates production and transmission plant using the average of the twelve monthly coincident peaks and 1/13 weighted average demand (12 CP and 1/13th) method. In addition, if the company is proposing a different cost allocation method, or if a different method was adopted in its last rate case, provide cost of service studies using these methods as well. All studies filed must be at both present and proposed rates. The cost of service analysis must be done separately for each rate class. If it is not possible to separate the costs of the lighting classes, the lighting classes can be combined.

Each cost study must include a schedule showing total revenues, total expenses, Net Operating Income, rate base, rate of return, rate of return index, revenue requirements at an equalized rate of return, revenue excess/deficiency, and revenue requirements index, for each rate class and for the total retail jurisdiction for the test year.

In all cost of service studies filed, the average of the 12 monthly peaks method must be used for the jurisdictional separation of the production and transmission plant and expenses unless the Federal Energy Regulatory Commission has approved another method in the utility's latest wholesale rate case. The minimum distribution system concept must not be used. The jurisdictional rate base and net operating income in the studies must equal the fully adjusted rate base in Schedule B-1 and the fully adjusted net operating income in Schedule C-1.

Costs and revenues for recovery clauses, franchise fees, and other items not recovered through base rates must be excluded from the cost of service study. Costs for service charges must be allocated consistently with the allocation of the collection of the revenues from these charges. Any other miscellaneous revenues must be allocated consistent with the allocation of the expense associated with the facilities used or services purchased.

If a historic test year is used, the twelve monthly peaks must be the hour of each month having the highest FIRM load, (i.e., exclude the load of non-firm customers in determining the peak hours).

Type of Data Shown:
X Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
___ Historical Year Ended 12/31/12
Witness: M. T. O'Sheasy

Line No.	
1	See Attachments A and B. Attachment A is the Cost of Service Study utilizing the
2	methods approved in the Company's last base rate case. Attachment B is the Cost of
3	Service Study without the Minimum Distribution System.

Supporting Schedules:

Recap Schedules:

ATTACHMENT A:

COST OF SERVICE STUDY

MINIMUM DISTRIBUTION SYSTEM METHODOLOGY

METHOD APPROVED IN GULF'S LAST RATE CASE

GULF POWER COMPANY
12 MONTHS ENDING DECEMBER 31, 2014
12/13 DEMAND ALLOCATION - WITH MDS METHODOLOGY
SCHEDULE 1.00 - PRESENT RATE SUMMARY
($000'S)

LINE NO. (1)	DESCRIPTION (2)	TOTAL ELECTRIC SYSTEM (3)	RATE CLASS RESIDENTIAL (4)	RATE CLASS GS (5)	RATE CLASS GSD/GSDT (6)	RATE CLASS LP/LPT (7)	RATE CLASS MAJOR ACCTS (8)	RATE CLASS OS (9)	TOTAL RETAIL SERVICE (10)	WHOLESALE (11)	UNIT POWER SALES (12)
	INVESTMENT										
1	ELECTRIC GROSS PLANT	3,391,076	1,720,955	99,776	580,715	225,760	227,889	89,073	2,944,168	55,729	391,179
2	ACCUMULATED DEPRECIATION	1,398,044	725,208	41,095	240,957	94,574	98,249	43,236	1,243,319	24,730	129,995
3	NET PLANT	1,993,032	995,747	58,681	339,758	131,186	129,640	45,837	1,700,849	30,999	261,184
4	MATERIALS AND SUPPLIES	154,358	70,673	3,601	33,712	14,556	15,953	2,316	141,011	3,814	9,533
5	OTHER WORKING CAPITAL	12,616	7,802	490	2,508	1,122	1,140	249	13,311	316	(1,011)
6	CONST. WORK IN PROGRESS	0	0	0	0	0	0	0	0	0	0
7	CWIP - NOT BEARING INTEREST	33,847	15,090	799	5,543	2,255	2,479	490	26,656	634	6,557
8	PLANT HELD FOR FUTURE USE	5,435	2,883	144	1,146	487	588	28	5,276	159	0
9	UNAMORT. PLANT ACQ. ADJUST.	1,903	0	0	0	0	0	0	0	0	1,903
10	INJURIES AND DAMAGES RESERVE	(3,354)	(2,027)	(163)	(555)	(194)	(204)	(59)	(3,202)	(54)	(98)
11	TOTAL ELECTRIC INVESTMENT	2,197,837	1,090,168	63,752	382,112	149,412	149,596	48,861	1,883,901	35,868	278,068
	REVENUES										
12	REVENUE FROM SALES	510,734	296,890	20,537	102,785	33,933	29,452	14,896	498,493	12,241	0
13	OTHER OPERATING REVENUES	69,171	37,651	2,368	11,161	9,377	3,320	1,401	65,278	3,893	0
14	REVENUE-NONASSOCIATED SALES	65,602	3,389	188	1,760	784	907	99	7,127	214	58,261
15	ADJUSTMENTS TO REVENUE	(42,247)	(25,162)	(1,740)	(8,711)	(2,876)	(2,496)	(1,262)	(42,247)	(0)	0
16	TOTAL ADJUSTED REVENUE	603,260	312,768	21,353	108,995	41,218	31,183	15,134	528,651	16,348	58,261
	EXPENSE										
17	OPERATIONS & MAINTENANCE	308,608	175,167	12,549	51,562	24,872	20,427	5,622	290,199	5,717	12,692
18	DEPRECIATION	114,402	61,471	3,747	20,152	7,658	7,716	3,761	104,505	1,922	7,975
19	AMORT. OF INV. TAX CREDIT	(1,224)	(517)	(31)	(169)	(64)	(65)	(32)	(878)	(16)	(330)
20	OTHER AMORTIZATION	0	0	0	0	0	0	0	0	0	0
21	REAL & PERSONAL PROP. TAX	26,010	13,896	756	5,040	2,083	2,245	495	24,515	580	915
22	PAYROLL TAX	6,917	4,108	332	1,180	415	437	127	6,599	114	204
23	REVENUE TAX	402	239	17	83	27	24	12	402	0	0
24	OTHER TAXES	41,572	24,744	1,709	8,569	2,835	2,471	1,233	41,561	11	0
25	ADJUSTMENT TO OTHER TAXES	(41,160)	(24,514)	(1,696)	(8,487)	(2,802)	(2,431)	(1,230)	(41,160)	0	0
26	EXPENSES EXCL. INC. TAX	455,527	254,594	17,383	77,930	35,024	30,824	9,988	425,743	8,328	21,456
27	OPERATING INCOME	147,733	58,174	3,970	29,065	6,194	359	5,146	102,908	8,020	36,805
28	STATE & FEDERAL INCOME TAX	34,876	10,889	856	7,163	806	(1,446)	1,467	19,735	2,714	12,227
29	INTEREST SYNCHRONIZATION	6,925	3,943	231	1,382	540	541	177	5,814	111	0
30	TOTAL INCOME TAXES	41,601	14,832	1,087	8,545	1,346	(905)	1,644	26,549	2,825	12,227
31	NET OPERATING INCOME	106,132	43,342	2,883	20,520	4,848	1,264	3,502	76,359	5,195	24,578
32	RATE OF RETURN	4.83%	3.98%	4.52%	5.37%	3.24%	0.84%	7.17%	4.05%		
33	RATE OF RETURN INDEX		98.09%	111.57%	132.49%	80.05%	20.85%	176.83%	100.00%		

GULF POWER COMPANY
12 MONTHS ENDED DECEMBER 31, 2014
12/13 DEMAND ALLOCATION - WITH MDS METHODOLOGY
PRESENT RATE SUMMARY

Line No.	Ftnt Label	Description
1	(A)	From "Analysis of Gross Plant"
2	(B)	From "Analysis of Accumulated Depreciation Reserve"
4	(C)	From "Analysis of Materials and Supplies"
5	(D)	From "Analysis of Other Working Capital"
6	(E)	From "Analysis of Other Rate Base Items"
7	(E)	
8	(E)	
9	(E)	
10	(E)	
12	(F)	From "Analysis of Revenues"
13	(F)	
14	(F)	
15	(F)	
17	(G)	From "Analysis of Operations and Maintenance Expense"
18	(H)	From "Analysis of Depreciation Expense"
19	(I)	Allocated per Depreciation Expense; UPS directly assigned
20	(J)	Allocated per Total Production Gross Plant excluding UPS
21	(K)	From "Analysis of Taxes Other Than Income Taxes"
22	(K)	
23	(K)	
24	(K)	
25	(K)	
28	(L)	Income Taxes allocated per formula t = Rc - KI : where t = Total Income Taxes, R = Operating Income, c = Combined Effective Tax Rate of 0.38575, I = Total Electric Investment, and K = Income Tax Deduction factor of 0.0105957953; UPS directly assigned.
29	(M)	Retail portion allocated per Retail Rate Base; Total All Other and UPS directly assigned.
32	(N)	Rate of Return equals Net Operating Income Divided by Total Electric Investment.
33	(O)	Each Rate Class Rate of Return divided by Total Retail Service Rate of Return

GULF POWER COMPANY
12 MONTHS ENDING DECEMBER 31, 2014
12/13 DEMAND ALLOCATION - WITH MDS METHODOLOGY
SCHEDULE 1.01 - EQUAL RATE OF RETURN SUMMARY - PRESENT RATES
($000'S)

LINE NO. (1)	DESCRIPTION (2)	TOTAL RETAIL SERVICE (3)	RATE CLASS RESIDENTIAL (4)	RATE CLASS GS (5)	RATE CLASS GSD/GSDT (6)	RATE CLASS LP/LPT (7)	RATE CLASS MAJOR ACCTS (8)	RATE CLASS OS (9)
1	EQUAL RATE OF RETURN	4.05%	4.05%	4.05%	4.05%	4.05%	4.05%	4.05%
2	PRESENT SYSTEM OPERATING INCOME	76,359	44,188	2,584	15,488	6,056	6,063	1,980
3	CURRENT OPERATING INCOME	76,359	43,342	2,883	20,520	4,848	1,264	3,502
4	CHANGE IN OPERATING INCOME	(0)	846	(299)	(5,032)	1,208	4,799	(1,522)
5	CHANGE IN INCOME TAXES	0	531	(188)	(3,160)	759	3,014	(956)
6	CURRENT INCOME TAXES	26,549	14,832	1,087	8,545	1,346	(905)	1,644
7	CHANGE IN EXPENSES	0	4	(2)	(30)	7	30	(9)
8	CURRENT EXPENSES	425,743	254,594	17,383	77,930	35,024	30,824	9,988
9	REV REQ - EQUAL SYSTEM ROR - PRESENT RATES	528,651	314,149	20,864	98,773	43,192	39,026	12,647
10	PRESENT REVENUE REQUIREMENTS	528,651	312,768	21,353	106,995	41,218	31,183	15,134
11	REVENUE EXCESS / DEFICIENCY	(0)	1,381	(489)	(8,222)	1,974	7,843	(2,487)
12	REV REQ INDEX - EQUAL SYSTEM ROR - PRES. RATES	100.00%	99.56%	102.34%	108.32%	95.43%	79.90%	119.66%

GULF POWER COMPANY
12 MONTHS ENDED DECEMBER 31, 2014
12/13 DEMAND ALLOCATION - WITH MDS METHODOLOGY
EQUAL RATE OF RETURN SUMMARY - PRESENT RATES

Line No.	Ftnt Label	Description
1	(A)	From "Present Rate Summary", Total Retail Service Rate of Return
2	(B)	Line 1 times Total Rate Base - "Present Rate Summary"
3	(C)	From "Present Rate Summary"
4	(D)	Line 2 minus Line 3
5	(E)	Line 4 times the combined effective tax rate divided by 1 minus the combined effective tax rate
6	(C)	
7	(F)	Line 4 plus Line 5 times the Proposed Expense Factor divided by 1 minus the Proposed Expense Factor
8	(C)	
9	(G)	Line 2 plus Lines 5 - 8.
10	(C)	
11	(H)	Line 9 minus Line 10
12	(I)	Line 10 divided by Line 9

GULF POWER COMPANY
12 MONTHS ENDING DECEMBER 31, 2014
12/13 DEMAND ALLOCATION - WITH MDS METHODOLOGY
SCHEDULE 1.10 - PROPOSED RATE SUMMARY
($000'S)

LINE NO. (1)	DESCRIPTION (2)	TOTAL ELECTRIC SYSTEM (3)	RATE CLASS RESIDENTIAL (4)	RATE CLASS GS (5)	RATE CLASS GSD/GSDT (6)	RATE CLASS LP/LPT (7)	RATE CLASS MAJOR ACCTS (8)	RATE CLASS OS (9)	TOTAL RETAIL SERVICE (10)	WHOLESALE (11)	UNIT POWER SALES (12)
1	TOTAL ELECTRIC INVESTMENT	2,197,837	1,090,168	63,752	382,112	149,412	149,596	48,861	1,883,901	35,868	278,068
	REVENUE										
2	PRESENT REVENUE	603,260	312,768	21,353	106,995	41,218	31,183	15,134	528,651	16,348	58,261
3	PROPOSED REVENUE	74,393	44,303	2,372	13,194	7,104	6,570	850	74,393	0	0
4	TOTAL REVENUE	677,653	357,071	23,725	120,189	48,322	37,753	15,984	603,044	16,348	58,261
	EXPENSE										
5	PRESENT OPERATING EXPENSES	455,527	254,594	17,383	77,930	35,024	30,824	9,988	425,743	8,328	21,456
6	PROPOSED EXPENSE INCREASE	272	162	9	48	26	24	3	272	0	0
7	TOTAL EXPENSES	455,799	254,756	17,392	77,978	35,050	30,848	9,991	426,015	8,328	21,456
8	OPERATING INCOME	221,854	102,315	6,333	42,211	13,272	6,905	5,993	177,029	8,020	36,805
	INCOME TAXES										
9	PRESENT INCOME TAXES	41,601	14,832	1,087	8,545	1,346	(905)	1,644	26,549	2,825	12,227
10	PROPOSED INC. TAX INCREASE	28,592	17,027	912	5,071	2,730	2,525	327	28,592	0	0
11	TOTAL INCOME TAXES	70,193	31,859	1,999	13,616	4,076	1,620	1,971	55,141	2,825	12,227
12	NET OPERATING INCOME	151,661	70,456	4,334	28,595	9,196	5,285	4,022	121,888	5,195	24,578
13	RATE OF RETURN	6.90%	6.46%	6.80%	7.48%	6.15%	3.53%	8.23%	6.47%		
14	RATE OF RETURN INDEX		99.89%	105.07%	115.66%	95.13%	54.60%	127.23%	100.00%		

GULF POWER COMPANY
12 MONTHS ENDED DECEMBER 31, 2014
12/13 DEMAND ALLOCATION - WITH MDS METHODOLOGY
PROPOSED RATE SUMMARY

Line No.	Ftnt Label	Description
1	(A)	From "Present Rate Summary"
2	(A)	
3	(B)	Provided by Pricing, Costing & Load Research, Gulf Power Company.
5	(A)	
6	(C)	Calculated by multiplying Proposed Revenues times the appropriate Proposed Expense Factor
8	(D)	Operating Income equals Total Revenue minus Total Expenses.
9	(A)	
10	(E)	Proposed Income Tax Increase calculated by multiplying Proposed Revenue minus Proposed Expense Increase times Effective Tax Rate of 0.38575.
12	(F)	Net Operating Income equals Operating Income less Total Income Taxes.
13	(G)	Rate of Return equals Net Operating Income Divided by Total Electric Investment.
14	(H)	Each Rate Class Rate of Return divided by Total Retail Service Rate of Return

GULF POWER COMPANY
12 MONTHS ENDING DECEMBER 31, 2014
12/13 DEMAND ALLOCATION - WITH MDS METHODOLOGY
SCHEDULE 1.11 - EQUAL RATE OF RETURN SUMMARY - PROPOSED RATES
($000'S)

LINE NO. (1)	DESCRIPTION (2)	TOTAL RETAIL SERVICE (3)	RATE CLASS RESIDENTIAL (4)	RATE CLASS GS (5)	RATE CLASS GSD/GSDT (6)	RATE CLASS LP/LPT (7)	RATE CLASS MAJOR ACCTS (8)	RATE CLASS OS (9)
1	EQUAL RATE OF RETURN	6.47%	6.47%	6.47%	6.47%	6.47%	6.47%	6.47%
2	PROPOSED OPERATING INCOME	121,888	70,534	4,125	24,723	9,667	9,679	3,161
3	CURRENT OPERATING INCOME	76,359	43,342	2,883	20,520	4,848	1,264	3,502
4	CHANGE IN OPERATING INCOME	45,530	27,192	1,242	4,203	4,819	8,415	(341)
5	CHANGE IN INCOME TAXES	28,592	17,076	780	2,639	3,026	5,285	(214)
6	PRESENT INCOME TAXES	26,549	14,832	1,087	8,545	1,346	(905)	1,644
7	CHANGE IN EXPENSES	273	162	7	25	29	51	(2)
8	PRESENT EXPENSES	425,743	254,594	17,383	77,930	35,024	30,824	9,988
9	REV REQ - EQUAL SYSTEM ROR - PROPOSED RATES	603,045	357,198	23,382	113,861	49,092	44,934	14,577
10	PRESENT REVENUE REQUIREMENTS	528,651	312,768	21,353	106,995	41,218	31,183	15,134
11	REVENUE EXCESS / DEFICIENCY	74,393	44,430	2,029	6,866	7,874	13,751	(557)
12	REV REQ INDEX - EQUAL SYSTEM ROR - PROP. RATES	87.66%	87.56%	91.32%	93.97%	83.96%	69.40%	103.82%

GULF POWER COMPANY
12 MONTHS ENDED DECEMBER 31, 2014
12/13 DEMAND ALLOCATION - WITH MDS METHODOLOGY
EQUAL RATE OF RETURN SUMMARY - PROPOSED RATES

Line No.	Ftnt Label	Description
1	(A)	From "Proposed Rate Summary", Total Retail Service Rate of Return
2	(B)	Line 1 times Total Rate Base - "Proposed Rate Summary"
3	(C)	From "Present Rate Summary"
4	(D)	Line 2 minus Line 3
5	(E)	Line 4 times the combined effective tax rate divided by 1 minus the combined effective tax rate
6	(C)	
7	(F)	Line 4 plus Line 5 times the Proposed Expense Factor divided by 1 minus the Proposed Expense Factor
8	(C)	
9	(G)	Line 2 plus Lines 5 - 8.
10	(C)	
11	(H)	Line 9 minus Line 10
12	(I)	Line 10 divided by Line 9

GULF POWER COMPANY
12 MONTHS ENDING DECEMBER 31, 2014
12/13 DEMAND ALLOCATION - WITH MDS METHODOLOGY
SCHEDULE 2.10 - ANALYSIS OF GROSS PLANT
($000'S)

LINE NO. (1)	DESCRIPTION (2)	TOTAL ELECTRIC SYSTEM (3)	RATE CLASS RESIDENTIAL (4)	RATE CLASS GS (5)	RATE CLASS GSD/GSDT (6)	RATE CLASS LP/LPT (7)	RATE CLASS MAJOR ACCTS (8)	RATE CLASS OS (9)	TOTAL RETAIL SERVICE (10)	WHOLESALE (11)	UNIT POWER SALES (12)
1	TOTAL PRODUCTION PLANT	1,571,047	627,458	30,856	252,627	107,929	130,774	5,721	1,155,365	35,508	380,174
	RETAIL JURISDICTION										
2	DEMAND		585,178	28,517	230,676	98,157	119,476	4,487	1,066,491		
3	ENERGY		42,280	2,339	21,951	9,772	11,298	1,234	88,874		
	TRANSMISSION PLANT										
	350-LAND & LAND RIGHTS										
1	SUBSTATIONS										
4	LEVEL 2 COMMON	1,541	821	40	323	138	167	6	1,495	46	0
5	LEVEL 3 COMMON	591	351	17	138	51	31	3	591	0	0
6	TOTAL SUBSTATION LAND	2,132	1,172	57	461	189	198	9	2,086	46	0
	LINES										
7	LEVEL 2 COMMON	18,183	9,678	472	3,816	1,624	1,977	74	17,641	542	0
8	TOTAL ACCOUNT 350	20,315	10,850	529	4,277	1,813	2,175	83	19,727	588	0
	352-STRUCTURES										
9	LEVEL 2 CUSTOMER SUB	2	0	0	0	0	2	0	2	0	0
10	LEVEL 2 COMMON	9,550	5,083	248	2,004	853	1,038	39	9,265	285	0
11	LEVEL 3 COMMON	1,439	853	42	337	125	75	7	1,439	0	0
12	TOTAL ACCOUNT 352	10,991	5,936	290	2,341	978	1,115	46	10,706	285	0
	353-STATION EQUIPMENT										
13	LEVEL 2 CUSTOMER SUB	140	0	0	0	0	140	0	140	0	0
14	LEVEL 2 COMMON	125,696	63,534	3,096	25,045	10,657	12,971	487	115,790	3,559	6,347
15	LEVEL 3 COMMON	38,170	22,657	1,104	8,931	3,305	1,999	174	38,170	0	0
16	TOTAL ACCOUNT 353	164,006	86,191	4,200	33,976	13,962	15,110	661	154,100	3,559	6,347
	354-TOWERS AND FIXTURES										
17	LEVEL 2 COMMON	42,804	22,787	1,110	8,962	3,822	4,652	175	41,528	1,276	0
	355-POLES AND FIXTURES										
18	LEVEL 2 COMMON	148,976	79,305	3,865	31,262	13,302	16,192	608	144,534	4,442	0
	356-OVERHEAD CONDUCTORS										
19	LEVEL 2 COMMON	85,526	45,529	2,219	17,947	7,637	9,295	349	82,976	2,550	0
	358-UNDERGROUND CONDUCTORS										
20	LEVEL 2 COMMON	14,095	7,502	366	2,958	1,259	1,532	58	13,675	420	0
	359-ROADS AND TRAILS										
21	LEVEL 2 COMMON	236	126	6	50	21	25	1	229	7	0
22	TOTAL TRANS. PLANT	486,949	258,226	12,585	101,793	42,794	50,096	1,961	467,475	13,127	6,347

GULF POWER COMPANY
12 MONTHS ENDING DECEMBER 31, 2014
12/13 DEMAND ALLOCATION - WITH MDS METHODOLOGY
SCHEDULE 2.10 - ANALYSIS OF GROSS PLANT
($000'S)

LINE NO. (1)	DESCRIPTION (2)	TOTAL ELECTRIC SYSTEM (3)	RATE CLASS RESIDENTIAL (4)	RATE CLASS GS (5)	RATE CLASS GSD/GSDT (6)	RATE CLASS LP/LPT (7)	RATE CLASS MAJOR ACCTS (8)	RATE CLASS OS (9)	TOTAL RETAIL SERVICE (10)	WHOLESALE (11)	UNIT POWER SALES (12)
	DISTRIBUTION PLANT										
	360-SUBSTATION LAND										
23	LEVEL 3 CUST. SUB	74	0	0	0	0	11	0	11	62	0
24	LEVEL 3 COMMON	4,584	2,720	133	1,073	397	240	21	4,584	0	0
25	LEVEL 4 COMMON	12	8	0	3	1	0	0	12	0	0
26	TOTAL ACCOUNT 360	4,670	2,728	133	1,076	398	251	21	4,607	62	0
	361-STRUCTURES										
27	LEVEL 3 CUST. SUB	2,007	0	0	0	617	963	0	1,581	426	0
28	LEVEL 3 COMMON	21,220	12,596	614	4,965	1,837	1,111	97	21,220	0	0
29	LEVEL 4 COMMON	0	0	0	0	0	0	0	0	0	0
30	TOTAL ACCOUNT 361	23,227	12,596	614	4,965	2,454	2,074	97	22,801	426	0
	362-STATION EQUIPMENT										
31	LEVEL 3 CUST. SUB	20,433	0	0	0	4,195	12,566	0	16,761	3,672	0
32	LEVEL 3 COMMON	205,570	122,021	5,946	48,100	17,799	10,768	936	205,570	0	0
33	LEVEL 4 COMMON	23	13	1	6	2	1	0	23	0	0
34	TOTAL ACCOUNT 362	226,026	122,034	5,947	48,106	21,996	23,335	936	222,354	3,672	0
	364-POLES AND FIXTURES										
35	LEVEL 4 COMMON	35,454	20,686	1,118	8,647	3,138	1,334	531	35,454	0	0
36	LEVEL 4 CUSTOMER	68,500	59,649	4,505	2,703	43	7	1,593	68,500	0	0
37	LEVEL 5 COMMON	10,168	6,310	341	2,621	715	19	162	10,168	0	0
38	LEVEL 5 CUSTOMER	19,667	17,128	1,294	775	11	1	458	19,667	0	0
39	TOTAL ACCOUNT 364	133,789	103,773	7,258	14,746	3,907	1,361	2,744	133,789	0	0
	365-OVERHEAD CONDUCTORS										
40	LEVEL 4 COMMON	89,998	52,507	2,838	21,951	7,967	3,387	1,348	89,998	0	0
41	LEVEL 4 CUSTOMER	17,614	15,338	1,158	695	11	2	410	17,614	0	0
42	LEVEL 5 COMMON	25,183	15,627	844	8,491	1,772	48	401	25,183	0	0
43	LEVEL 5 CUSTOMER	4,816	4,194	317	190	3	0	112	4,816	0	0
44	TOTAL ACCOUNT 365	137,611	87,666	5,157	29,327	9,753	3,437	2,271	137,611	0	0
	366-UNDERGROUND CONDUIT										
45	LEVEL 4 COMMON	664	387	21	162	59	25	10	664	0	0
46	LEVEL 4 CUSTOMER	33	29	2	1	0	0	1	33	0	0
47	LEVEL 5 COMMON	450	279	16	116	32	1	7	450	0	0
48	LEVEL 5 CUSTOMER	14	12	1	1	0	0	0	14	0	0
49	TOTAL ACCOUNT 366	1,161	707	39	280	91	26	18	1,161	0	0
	367-UNDERGROUND COND. & DEV.										
50	LEVEL 4 COMMON	99,396	57,991	3,134	24,243	8,799	3,740	1,489	99,396	0	0
51	LEVEL 4 CUSTOMER	4,845	4,218	319	191	3	1	113	4,845	0	0
52	LEVEL 5 COMMON	40,669	25,235	1,364	10,483	2,861	78	648	40,669	0	0
53	LEVEL 5 CUSTOMER	1,908	1,663	125	75	1	0	44	1,908	0	0
54	TOTAL ACCOUNT 367	146,818	89,107	4,942	34,992	11,664	3,819	2,294	148,818	0	0

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Attachment A to Sch. E-1
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GULF POWER COMPANY
12 MONTHS ENDING DECEMBER 31, 2014
12/13 DEMAND ALLOCATION - WITH MDS METHODOLOGY
SCHEDULE 2.10 - ANALYSIS OF GROSS PLANT
($000'S)

LINE NO. (1)	DESCRIPTION (2)	TOTAL ELECTRIC SYSTEM (3)	RATE CLASS RESIDENTIAL (4)	RATE CLASS GS (5)	RATE CLASS GSD/GSDT (6)	RATE CLASS LP/LPT (7)	RATE CLASS MAJOR ACCTS (8)	RATE CLASS OS (9)	TOTAL RETAIL SERVICE (10)	WHOLESALE (11)	UNIT POWER SALES (12)
	368-LINE TRANSFORMERS										
55	LEVEL 4 COMMON	35,271	20,579	1,112	8,603	3,122	1,327	528	35,271	0	0
56	LEVEL 4 CUSTOMER	4,314	3,757	284	170	3	0	100	4,314	0	0
57	LEVEL 5 COMMON	154,026	95,575	5,165	39,703	10,635	294	2,454	154,026	0	0
58	LEVEL 5 CUSTOMER	60,139	52,376	3,956	2,370	34	4	1,399	60,139	0	0
59	TOTAL ACCOUNT 368	253,750	172,287	10,517	50,846	13,994	1,625	4,481	253,750	0	0
	369-SERVICES										
60	HOUSE POWER BOXES	0	0	0	0	0	0	0	0	0	0
61	OTHER SERVICES	99,675	88,877	6,712	4,021	57	8	0	99,675	0	0
62	TOTAL ACCOUNT 369	99,675	88,877	6,712	4,021	57	8	0	99,675	0	0
63	370-METERS	65,096	48,878	6,437	8,768	494	266	138	64,981	115	0
64	373-STREET LIGHTING	65,351	0	0	0	0	0	65,351	65,351	0	0
65	TOTAL DIST. PLANT	1,157,174	728,653	47,756	197,127	64,809	36,203	78,351	1,152,898	4,278	0
66	DEMAND	745,202	432,534	22,646	177,167	64,149	35,914	8,632	741,041	4,161	0
67	CUSTOMER	411,972	296,119	25,110	19,960	660	289	69,719	411,857	115	0
	GENERAL PLANT										
68	ELECTRIC	175,906	106,618	8,579	29,168	10,228	10,817	3,020	168,430	2,818	4,658
69	DEMAND	106,101	55,114	2,737	21,951	8,928	9,487	597	98,814	2,629	4,658
70	CUSTOMER	63,809	48,650	5,686	5,736	642	567	2,340	63,620	189	0
71	ENERGY	5,996	2,854	157	1,481	658	763	83	5,996	0	0
72	TOTAL GENERAL PLANT	175,906	106,618	8,579	29,168	10,228	10,817	3,020	168,430	2,818	4,658
73	TOTAL ELEC. GROSS PLANT	3,391,076	1,720,955	99,776	580,715	225,760	227,889	89,073	2,944,168	55,729	391,179
74	DEMAND	2,820,424	1,331,052	66,485	531,587	214,028	214,972	15,697	2,373,821	55,425	391,179
75	CUSTOMER	475,781	344,769	30,795	25,696	1,302	856	72,059	475,477	304	0
76	ENERGY	94,870	45,134	2,496	23,432	10,430	12,061	1,317	94,870	0	0

GULF POWER COMPANY
12 MONTHS ENDED DECEMBER 31, 2014
12/13 DEMAND ALLOCATION - WITH MDS METHODOLOGY
ANALYSIS OF GROSS PLANT

Line No.	Ftnt Label	Description
1	(A)	Retail jurisdiction sum of Lines 2 and 3; Wholesale allocated per Level 1 Demand Allocator; UPS directly assigned.
2	(B)	Allocated per corresponding Level 1 Demand Allocator.
3	(C)	Allocated per corresponding Level 1 Energy Allocator.
4	(D)	Allocated per Level 2 Demand Allocator; UPS directly assigned.
5	(E)	Allocated per Level 3 Demand Allocator.
7	(D)	
9	(F)	Specific Assignment
10	(D)	
11	(E)	
13	(F)	
14	(D)	
15	(E)	
17	(D)	
18	(D)	
19	(D)	
20	(D)	
21	(D)	
23	(F)	
24	(E)	
25	(G)	Allocated per Level 4 NCP Demand Allocator
27	(F)	
28	(E)	
29	(G)	
31	(F)	
32	(E)	
33	(G)	
35	(G)	
36	(H)	Allocated per Average Number of Customers at Level 4 and Level 5.
37	(I)	Allocated per Level 5 NCP Demand Allocator
38	(J)	Allocated per Average Number of Customers at Level 5.

GULF POWER COMPANY
12 MONTHS ENDED DECEMBER 31, 2014
12/13 DEMAND ALLOCATION - WITH MDS METHODOLOGY
ANALYSIS OF GROSS PLANT

Line No.	Ftnt Label	Description
40	(G)	
41	(H)	
42	(I)	
43	(J)	
45	(G)	
46	(H)	
47	(I)	
48	(J)	
50	(G)	
51	(H)	
52	(I)	
53	(J)	
55	(G)	
56	(H)	
57	(I)	
58	(J)	
60	(F)	
61	(K)	Allocated per Average Number of Customers at Level 5 excluding Rate OS.
63	(L)	Provided by Gulf Power Company
64	(F)	
68	(M)	Allocated per corresponding Salaries and Wages; UPS directly assigned.
69	(M)	
70	(M)	
71	(M)	

GULF POWER COMPANY
12 MONTHS ENDING DECEMBER 31, 2014
12/13 DEMAND ALLOCATION - WITH MDS METHODOLOGY
SCHEDULE 2.20 - ANALYSIS OF ACCUMULATED DEPRECIATION RESERVE
($000'S)

LINE NO. (1)	DESCRIPTION (2)	TOTAL ELECTRIC SYSTEM (3)	RATE CLASS RESIDENTIAL (4)	RATE CLASS GS (5)	RATE CLASS GSD/GSDT (6)	RATE CLASS LP/LPT (7)	RATE CLASS MAJOR ACCTS (8)	RATE CLASS OS (9)	TOTAL RETAIL SERVICE (10)	WHOLESALE (11)	UNIT POWER SALES (12)
1	TOTAL PRODUCTION	759,866	334,127	16,432	134,526	57,474	69,638	3,046	615,243	18,908	125,715
	RETAIL JURISDICTION										
2	DEMAND		311,613	15,186	122,837	52,270	63,622	2,389	567,917		
3	ENERGY		22,514	1,246	11,689	5,204	6,016	657	47,326		
	TRANSMISSION										
4	350-LAND AND LAND RIGHTS	6,816	3,629	177	1,430	609	740	28	6,613	203	0
5	352-STRUCTURES	3,645	1,969	96	776	324	370	15	3,550	95	0
6	353-STATION EQUIPMENT	32,146	16,252	792	6,406	2,633	2,849	125	29,057	671	2,418
7	354-TOWERS & FIXTURES	25,433	13,539	660	5,337	2,271	2,764	104	24,675	758	0
8	355-POLES & FIXTURES	26,313	14,007	683	5,522	2,349	2,860	107	25,528	785	0
9	356-OVERHEAD COND.	26,168	13,930	679	5,491	2,337	2,844	107	25,388	780	0
10	358-UNDERGROUND COND.	7,657	4,075	199	1,607	684	832	32	7,429	228	0
11	359-ROADS AND TRAILS	40	22	1	8	4	4	0	39	1	0
12	TOTAL TRANSMISSION	128,218	67,423	3,287	26,577	11,211	13,263	518	122,279	3,521	2,418
	DISTRIBUTION										
13	360-SUBSTATION LAND	35	21	1	8	3	2	0	35	0	0
14	361-STRUCTURES	7,861	4,262	208	1,680	831	703	33	7,717	144	0
15	362-STATION EQUIPMENT	61,193	33,040	1,610	13,024	5,955	6,317	253	60,199	994	0
	364-POLES & FIXTURES										
16	COMMON	23,472	13,889	751	5,797	1,982	696	357	23,472	0	0
17	CUSTOMER	45,360	39,499	2,983	1,791	28	4	1,055	45,360	0	0
18	TOTAL ACCOUNT 364	68,832	53,388	3,734	7,588	2,010	700	1,412	68,832	0	0
	365-OVERHEAD COND.										
19	COMMON	40,725	24,091	1,302	10,056	3,443	1,215	618	40,725	0	0
20	CUSTOMER	7,931	6,907	521	313	5	0	185	7,931	0	0
21	TOTAL ACCOUNT 365	48,656	30,998	1,823	10,369	3,448	1,215	803	48,656	0	0

GULF POWER COMPANY
12 MONTHS ENDING DECEMBER 31, 2014
12/13 DEMAND ALLOCATION - WITH MDS METHODOLOGY
SCHEDULE 2.20- ANALYSIS OF ACCUMULATED DEPRECIATION RESERVE
($000'S)

LINE NO. (1)	DESCRIPTION (2)	TOTAL ELECTRIC SYSTEM (3)	RATE CLASS RESIDENTIAL (4)	RATE CLASS GS (5)	RATE CLASS GSD/GSDT (6)	RATE CLASS LP/LPT (7)	RATE CLASS MAJOR ACCTS (8)	RATE CLASS OS (9)	TOTAL RETAIL SERVICE (10)	WHOLESALE (11)	UNIT POWER SALES (12)
	366-UNDG. CONDUIT										
22	COMMON	768	457	25	193	63	18	12	768	0	0
23	CUSTOMER	32	29	2	1	0	0	0	32	0	0
24	TOTAL ACCOUNT 366	800	486	27	194	63	18	12	800	0	0
	367-UNDERGROUND COND. & DEV.										
25	COMMON	50,298	29,887	1,615	12,471	4,187	1,371	767	50,298	0	0
26	CUSTOMER	2,425	2,110	160	96	2	0	57	2,425	0	0
27	TOTAL ACCOUNT 367	52,723	31,997	1,775	12,567	4,189	1,371	824	52,723	0	0
	368-LINE TRANSFORMERS										
28	COMMON	69,302	42,524	2,298	17,685	5,110	593	1,092	69,302	0	0
29	CUSTOMER	23,597	20,551	1,552	930	13	2	549	23,597	0	0
30	TOTAL ACCOUNT 368	92,899	63,075	3,850	18,615	5,123	595	1,641	92,899	0	0
31	369-SERVICES	50,834	45,327	3,423	2,051	29	4	0	50,834	0	0
32	370-METERS	21,743	18,057	1,464	1,993	112	60	31	21,717	26	0
33	373-STREET LIGHTING	33,445	0	0	0	0	0	33,445	33,445	0	0
34	TOTAL DISTRIBUTION	439,021	280,651	17,915	68,089	21,763	10,985	38,454	437,857	1,164	0
35	DEMAND	253,654	148,171	7,810	60,914	21,574	10,915	3,132	252,516	1,138	0
36	CUSTOMER	185,367	132,480	10,105	7,175	189	70	35,322	185,341	26	0
	GENERAL PLANT										
	ELECTRIC										
37	DEMAND	42,781	22,232	1,104	8,854	3,601	3,827	241	39,859	1,060	1,862
38	CUSTOMER	25,739	19,624	2,293	2,314	259	229	944	25,663	76	0
39	ENERGY	2,419	1,151	64	597	266	307	33	2,418	1	0
40	TOTAL ELECTRIC GENERAL PLANT	70,939	43,007	3,461	11,765	4,126	4,363	1,218	67,940	1,137	1,862
41	TOTAL ELECTRIC DEPR. RESERVE	1,398,044	725,208	41,095	240,957	94,574	98,249	43,236	1,243,319	24,730	129,995
42	DEMAND	1,137,193	549,439	27,387	219,182	88,656	91,627	6,280	982,571	24,627	129,995
43	CUSTOMER	211,106	152,104	12,398	9,489	448	299	36,266	211,004	102	0
44	ENERGY	49,745	23,665	1,310	12,286	5,470	6,323	690	49,744	1	0

GULF POWER COMPANY
12 MONTHS ENDED DECEMBER 31, 2014
12/13 DEMAND ALLOCATION - WITH MDS METHODOLOGY
ANALYSIS OF ACCUMULATED DEPRECIATION RESERVE

Line No.	Ftnt Label	Description
1	(A)	Retail jurisdiction sum of Lines 2 and 3; Wholesale allocated per Level 1 Demand Allocator; UPS directly assigned.
2	(B)	Allocated per corresponding Level 1 Demand Allocator.
3	(C)	Allocated per corresponding Level 1 Energy Allocator.
4	(D)	Allocated per Transmission Account 350 Gross Plant (Lines portion only); UPS directly assigned.
5	(E)	Allocated per corresponding Transmission Gross Plant; UPS directly assigned.
6	(E)	
7	(E)	
8	(E)	
9	(E)	
10	(E)	
11	(E)	
13	(F)	Allocated per corresponding Distribution Gross Plant.
14	(F)	
15	(F)	
16	(F)	
17	(F)	
19	(F)	
20	(F)	
22	(F)	
23	(F)	
25	(F)	
26	(F)	
28	(F)	
29	(F)	
31	(F)	
32	(F)	
33	(F)	
37	(G)	Allocated per corresponding Gross General Plant; UPS directly assigned.
38	(G)	
39	(G)	

GULF POWER COMPANY
12 MONTHS ENDING DECEMBER 31, 2014
12/13 DEMAND ALLOCATION - WITH MDS METHODOLOGY
SCHEDULE 2.30 - ANALYSIS OF MATERIALS AND SUPPLIES
($000'S)

LINE NO. (1)	DESCRIPTION (2)	TOTAL ELECTRIC SYSTEM (3)	RATE CLASS RESIDENTIAL (4)	RATE CLASS GS (5)	RATE CLASS GSD/GSDT (6)	RATE CLASS LP/LPT (7)	RATE CLASS MAJOR ACCTS (8)	RATE CLASS OS (9)	TOTAL RETAIL SERVICE (10)	WHOLESALE (11)	UNIT POWER SALES (12)
	PRODUCTION										
1	NON-FUEL	30,413	14,766	726	5,943	2,539	3,074	135	27,183	900	2,330
	RETAIL JURISDICTION										
2	DEMAND		13,768	671	5,427	2,309	2,811	106	25,092		
3	ENERGY		998	55	516	230	263	29	2,091		
4	FUEL	103,229	44,350	2,454	23,026	10,250	11,851	1,294	93,225	2,801	7,203
5	TOTAL PRODUCTION M & S	133,642	59,116	3,180	28,969	12,789	14,925	1,429	120,408	3,701	9,533
	TRANSMISSION										
6	LINES RELATED	2,495	1,328	65	524	223	271	10	2,421	74	0
7	SUBSTATION RELATED	1,687	922	45	363	149	163	7	1,649	38	0
8	TOTAL TRANS. M & S	4,182	2,250	110	887	372	434	17	4,070	112	0
	DISTRIBUTION										
9	DEMAND RELATED	15,483.200	9,033	488	3,776	1,371	583	232	15,483	0	0
10	METERING RELATED	166.000	127	16	22	1	0	0	166	0	0
11	ST. LIGHTING RELATED	634.771	0	0	0	0	0	635	635	0	0
12	OTHER	240.421	140	7	57	21	11	3	239	1	0
13	TOTAL DIST. M & S	16,525	9,301	511	3,855	1,393	594	870	16,524	1	0
14	CUSTOMER ACCOUNTS	5	5	0	0	0	0	0	5	0	0
15	CUSTOMER ASSISTANCE	5	2	0	1	2	0	0	5	0	0
16	TOTAL ELECTRIC M & S	154,358	70,673	3,801	33,712	14,556	15,953	2,316	141,011	3,814	9,533
17	DEMAND	48,228	25,192	1,276	10,147	4,073	3,839	358	44,885	1,013	2,330
18	CUSTOMER	811	134	16	23	3	0	635	811	0	0
19	ENERGY	105,320	45,348	2,509	23,542	10,480	12,114	1,323	95,316	2,801	7,203

GULF POWER COMPANY
12 MONTHS ENDED DECEMBER 31, 2014
12/13 DEMAND ALLOCATION - WITH MDS METHODOLOGY
ANALYSIS OF MATERIALS AND SUPPLIES

Line No.	Ftnt Label	Description
1	(A)	Retail jurisdiction sum of Lines 2 and 3; Wholesale allocated per Level 1 Demand Allocator; UPS directly assigned.
2	(B)	Allocated per corresponding Level 1 Demand Allocator.
3	(C)	Allocated per corresponding Level 1 Energy Allocator.
4	(D)	Allocated per Level 1 Energy Allocator; UPS directly assigned.
6	(E)	Allocated per Level 2 Demand Allocator; UPS directly assigned.
7	(F)	Allocated per Gross Investment in Transmission Substations excluding UPS.
9	(G)	Allocated per Level 4 NCP Demand Allocator.
10	(H)	Allocated per Distribution Gross Plant in Account 370.
11	(I)	Directly assigned to Street Lighting.
12	(J)	Allocated per Demand-related Distribution Gross Plant.
14	(K)	Allocated per Customer Accounts O & M Expense.
15	(L)	Allocated per Customer Assistance O & M Energy Cost Conservation.

GULF POWER COMPANY
12 MONTHS ENDING DECEMBER 31, 2014
12/13 DEMAND ALLOCATION - WITH MDS METHODOLOGY
SCHEDULE 2.40 - ANALYSIS OF OTHER WORKING CAPITAL
($000'S)

LINE NO. (1)	DESCRIPTION (2)	TOTAL ELECTRIC SYSTEM (3)	RATE CLASS RESIDENTIAL (4)	RATE CLASS GS (5)	RATE CLASS GSO/GSDT (6)	RATE CLASS LP/LPT (7)	RATE CLASS MAJOR ACCTS (8)	RATE CLASS OS (9)	TOTAL RETAIL SERVICE (10)	WHOLESALE (11)	UNIT POWER SALES (12)
	OTHER WORKING CAPITAL										
1	CURRENT ASSETS & LIAB.	(7,220)	(4,280)	(308)	(1,181)	(565)	(444)	(140)	(6,918)	(128)	(174)
2	DEMAND	(4,624)	(2,425)	(121)	(966)	(392)	(411)	(27)	(4,342)	(108)	(174)
3	CUSTOMER	(2,303)	(1,676)	(176)	(166)	(155)	(14)	(109)	(2,296)	(7)	0
4	ENERGY	(113)	(51)	(2)	(30)	(13)	(15)	(2)	(113)	0	0
5	REVENUE RELATED	(160)	(128)	(9)	(19)	(5)	(4)	(2)	(167)	(13)	0
6	CABLE ATTACHMENTS	(2,327)	(1,380)	(100)	(380)	(182)	(142)	(46)	(2,230)	(41)	(56)
7	DEMAND	(1,490)	(782)	(39)	(311)	(126)	(132)	(9)	(1,399)	(35)	(56)
8	CUSTOMER	(742)	(540)	(57)	(54)	(50)	(4)	(35)	(740)	(2)	0
9	ENERGY	(35)	(16)	(1)	(9)	(4)	(5)	(1)	(36)	0	0
10	REVENUE RELATED	(58)	(42)	(3)	(6)	(2)	(1)	(1)	(55)	(4)	0
	PREPAYMENTS										
11	PRODUCTION	7,233	3,682	181	1,483	633	768	33	6,780	208	245
	RETAIL JURISDICTION										
12	DEMAND		3,434	167	1,354	576	701	26	6,258		
13	ENERGY		248	14	129	57	67	7	522		
14	TRANSMISSION	2,680	1,439	70	568	239	280	11	2,607	73	0
15	DISTRIBUTION	6,567	4,138	272	1,114	366	204	449	6,543	24	0
16	DEMAND	4,206	2,441	128	1,000	362	203	49	4,183	23	0
17	CUSTOMER	2,361	1,697	144	114	4	1	400	2,360	1	0
18	CUSTOMER ACCOUNTS	124	108	8	5	0	0	2	123	1	0
19	CUSTOMER ASSSISTANCE	130	58	12	15	43	2	0	130	0	0
20	CUSTOMER	130	58	12	15	43	2	0	130	0	0
21	ENERGY	0	0	0	0	0	0	0	0	0	0
22	TOTAL PREPAYMENTS	18,734	9,425	543	3,185	1,281	1,254	495	16,183	306	245
23	DEMAND	13,597	7,314	365	2,922	1,177	1,184	86	13,048	304	245
24	CUSTOMER	2,615	1,863	164	134	47	3	402	2,613	2	0
25	ENERGY	522	248	14	129	57	67	7	522	0	0
26	PRELIM. SURVEY & INVESTIGATION	5,238	2,760	135	1,112	475	575	25	5,082	156	0
	RETAIL JURISDICTION										
27	DEMAND		2,574	125	1,015	432	525	20	4,691		
28	ENERGY		186	10	97	43	50	5	391		
	OTHER INVESTMENTS										
29	PRODUCTION	34,471	18,162	892	7,313	3,124	3,787	165	33,443	1,028	0
	RETAIL JURISDICTION										
30	DEMAND		16,939	825	6,677	2,841	3,459	129	30,870		
31	ENERGY		1,223	67	636	283	328	36	2,573		
32	TRANSMISSION	3,015	1,610	77	634	270	324	12	2,927	88	0
33	DISTRIBUTION	16,142	10,917	726	2,473	731	293	987	16,127	15	0
34	DEMAND	8,610	5,097	272	2,107	719	288	115	8,598	12	0
35	CUSTOMER	7,532	5,819	454	366	12	6	872	7,529	3	0

GULF POWER COMPANY
12 MONTHS ENDING DECEMBER 31, 2014
12/13 DEMAND ALLOCATION - WITH MDS METHODOLOGY
SCHEDULE 2.40 - ANALYSIS OF OTHER WORKING CAPITAL
($000'S)

LINE NO. (1)	DESCRIPTION (2)	TOTAL ELECTRIC SYSTEM (3)	RATE CLASS RESIDENTIAL (4)	RATE CLASS GS (5)	RATE CLASS GSD/GSDT (6)	RATE CLASS LP/LPT (7)	RATE CLASS MAJOR ACCTS (8)	RATE CLASS OS (9)	TOTAL RETAIL SERVICE (10)	WHOLESALE (11)	UNIT POWER SALES (12)
36	CUSTOMER ACCOUNTS	9,660	8,406	635	382	10	17	132	9,582	78	0
37	CUSTOMER ASSISTANCE	10,185	6,649	1,349	1,713	253	221	0	10,185	0	0
38	CUSTOMER	10,186	6,649	1,349	1,713	253	221	0	10,185	0	0
39	ENERGY	0	0	0	0	0	0	0	0	0	0
40	TOTAL OTHER INVESTMENTS	73,473	45,743	3,679	12,515	4,388	4,643	1,296	72,264	1,209	0
41	DEMAND	43,523	23,646	1,174	9,418	3,830	4,071	256	42,395	1,128	0
42	CUSTOMER	27,377	20,874	2,438	2,461	275	244	1,004	27,296	81	0
43	ENERGY	2,573	1,223	67	636	283	328	36	2,573	0	0
44	ENVIRONMENTAL CLEANUP	58,878	34,878	2,517	9,633	4,613	3,635	1,138	56,414	1,047	1,417
45	DEMAND	37,709	19,773	984	7,880	3,196	3,356	218	35,407	885	1,417
46	CUSTOMER	16,777	13,659	1,437	1,356	1,266	116	888	16,722	55	0
47	ENERGY	924	410	20	243	109	128	14	924	0	0
48	REVENUE RELATED	1,469	1,036	76	154	42	35	18	1,361	107	0
49	PROP. INSURANCE RESERVE	(16,782)	(8,857)	(523)	(3,023)	(1,168)	(1,154)	(408)	(15,133)	(276)	(1,373)
50	DEMAND	(14,026)	(8,953)	(348)	(2,780)	(1,116)	(1,098)	(84)	(12,379)	(274)	(1,373)
51	CUSTOMER	(2,355)	(1,714)	(164)	(144)	(8)	(5)	(318)	(2,353)	(2)	0
52	ENERGY	(401)	(190)	(11)	(99)	(44)	(51)	(6)	(401)	0	0
	OTHER POST RETIREMENT BENEFITS										
53	PRODUCTION	(33,276)	(17,534)	(862)	(7,059)	(3,016)	(3,655)	(159)	(32,285)	(991)	0
	RETAIL JURISDICTION										
54	DEMAND		(16,353)	(797)	(6,446)	(2,743)	(3,338)	(125)	(29,802)		
55	ENERGY		(1,161)	(65)	(613)	(273)	(317)	(34)	(2,483)		
56	TRANSMISSION	(2,911)	(1,553)	(75)	(612)	(261)	(314)	(11)	(2,826)	(85)	0
57	DISTRIBUTION	(15,582)	(10,539)	(701)	(2,387)	(706)	(283)	(952)	(15,568)	(14)	0
58	DEMAND	(8,311)	(4,922)	(262)	(2,034)	(694)	(277)	(111)	(8,300)	(11)	0
59	CUSTOMER	(7,271)	(5,619)	(439)	(353)	(11)	(6)	(841)	(7,268)	(3)	0
60	CUSTOMER ACCOUNTS	(9,325)	(8,113)	(613)	(369)	(10)	(16)	(128)	(9,249)	(76)	0
61	CUSTOMER ASSISTANCE	(9,831)	(8,415)	(1,303)	(1,654)	(245)	(214)	0	(9,831)	0	0
62	CUSTOMER	(9,831)	(6,415)	(1,303)	(1,654)	(245)	(214)	0	(9,831)	0	0
63	ENERGY	0	0	0	0	0	0	0	0	0	0
64	TOTAL OTHER POST RETIREMENT BENEFITS	(70,925)	(44,156)	(3,553)	(12,081)	(4,237)	(4,482)	(1,250)	(69,759)	(1,166)	0
65	DEMAND	(42,015)	(22,826)	(1,134)	(9,092)	(3,698)	(3,929)	(247)	(40,928)	(1,087)	0
66	CUSTOMER	(26,427)	(20,147)	(2,354)	(2,376)	(266)	(236)	(969)	(26,348)	(79)	0
67	ENERGY	(2,483)	(1,181)	(65)	(613)	(273)	(317)	(34)	(2,483)	0	0
68	OTHER DEF. CR. & DEBITS	(44,453)	(28,331)	(1,900)	(7,272)	(3,483)	(2,745)	(861)	(42,592)	(791)	(1,070)
69	DEMAND	(28,470)	(14,928)	(743)	(5,949)	(2,413)	(2,534)	(165)	(26,732)	(668)	(1,070)
70	CUSTOMER	(14,177)	(10,311)	(1,085)	(1,024)	(956)	(88)	(671)	(14,135)	(42)	0
71	ENERGY	(697)	(309)	(15)	(183)	(83)	(96)	(11)	(697)	0	0
72	REVENUE RELATED	(1,109)	(783)	(57)	(116)	(31)	(27)	(14)	(1,028)	(81)	0
	UNAMORT. RATE CASE EXP.										
73	REVENUE RELATED	0	0	0	0	0	0	0	0	0	0
74	TOTAL OTHER WORK. CAP.	12,616	7,802	490	2,508	1,122	1,140	249	13,311	316	(1,011)
75	DEMAND	9,051	5,391	263	2,137	890	1,032	48	9,761	301	(1,011)
76	CUSTOMER	2,765	2,008	203	187	153	16	192	2,759	6	0
77	ENERGY	680	320	17	171	75	89	8	680	0	0
78	REVENUE RELATED	120	83	7	13	4	3	1	111	9	0

GULF POWER COMPANY
12 MONTHS ENDED DECEMBER 31, 2014
12/13 DEMAND ALLOCATION - WITH MDS METHODOLOGY
ANALYSIS OF OTHER WORKING CAPITAL

Line No.	Ftnt Label	Description
1	(A)	Allocated per Total Expenses less Production Energy related O & M, Income taxes, and Non-cash items.
2	(A)	
3	(A)	
4	(A)	
5	(A)	
6	(A)	
7	(A)	
8	(A)	
9	(A)	
10	(A)	
11	(B)	Allocated per corresponding Gross Plant; UPS directly assigned.
12	(C)	Allocated per corresponding Gross Plant.
13	(C)	
14	(B)	
15	(C)	
16	(C)	
17	(C)	
18	(D)	Allocated per corresponding Operations and Maintenance Expense.
19	(D)	
20	(D)	
21	(D)	
26	(E)	Allocated per Production Gross Plant; UPS directly assigned.
27	(F)	Allocated per corresponding Production Gross Plant.
28	(F)	
29	(G)	Allocated per corresponding Salaries and Wages
30	(G)	
31	(G)	
32	(G)	
33	(G)	
34	(G)	
35	(G)	
36	(G)	
37	(G)	
38	(G)	
39	(G)	

GULF POWER COMPANY
12 MONTHS ENDED DECEMBER 31, 2014
12/13 DEMAND ALLOCATION - WITH MDS METHODOLOGY
ANALYSIS OF OTHER WORKING CAPITAL

Line No.	Ftnt Label	Description
44	(A)	
45	(A)	
46	(A)	
47	(A)	
48	(A)	
49	(H)	Allocated per Total Net Plant; UPS directly assigned.
50	(H)	
51	(I)	Allocated per Total Net Plant.
52	(I)	
53	(G)	
54	(G)	
55	(G)	
56	(G)	
57	(G)	
58	(G)	
59	(G)	
60	(G)	
61	(G)	
62	(G)	
63	(G)	
68	(A)	
69	(A)	
70	(A)	
71	(A)	
72	(A)	
73	(J)	Allocated per Retail Revenue from Sales.

GULF POWER COMPANY
12 MONTHS ENDING DECEMBER 31, 2014
12/13 DEMAND ALLOCATION - WITH MDS METHODOLOGY
SCHEDULE 2.50 - ANALYSIS OF OTHER RATE BASE ITEMS
($000'S)

LINE NO. (1)	DESCRIPTION (2)	TOTAL ELECTRIC SYSTEM (3)	RATE CLASS RESIDENTIAL (4)	RATE CLASS GS (5)	RATE CLASS GSD/GSDT (6)	RATE CLASS LP/LPT (7)	RATE CLASS MAJOR ACCTS (8)	RATE CLASS OS (9)	TOTAL RETAIL SERVICE (10)	WHOLESALE (11)	UNIT POWER SALES (12)
	CONST. WORK IN PROGRESS INTEREST BEARING										
1	PRODUCTION	0	0	0	0	0	0	0	0	0	0
	RETAIL JURISDICTION										
2	DEMAND		0	0	0	0	0	0	0		
3	ENERGY		0	0	0	0	0	0	0		
4	TRANSMISSION	0	0	0	0	0	0	0	0	0	0
5	DISTRIBUTION	0	0	0	0	0	0	0	0	0	0
6	DEMAND	0	0	0	0	0	0	0	0	0	0
7	CUSTOMER	0	0	0	0	0	0	0	0	0	0
8	CUSTOMER ACCOUNTS	0	0	0	0	0	0	0	0	0	0
9	CUSTOMER ASSISTANCE	0	0	0	0	0	0	0	0	0	0
10	CUSTOMER	0	0	0	0	0	0	0	0	0	0
11	ENERGY	0	0	0	0	0	0	0	0	0	0
12	TOTAL CWIP	0	0	0	0	0	0	0	0	0	0
13	DEMAND	0	0	0	0	0	0	0	0	0	0
14	CUSTOMER	0	0	0	0	0	0	0	0	0	0
15	ENERGY	0	0	0	0	0	0	0	0	0	0
	CONST. WORK IN PROGRESS WORK NOT BEARING INTEREST										
16	PRODUCTION	17,325	5,673	279	2,285	976	1,182	52	10,447	321	6,557
	RETAIL JURISDICTION										
17	DEMAND		5,290	258	2,086	888	1,080	41	9,643		
18	ENERGY		383	21	199	88	102	11	804		
19	TRANSMISSION	10,704	5,753	280	2,267	953	1,115	44	10,412	292	0
20	DISTRIBUTION	5,818	3,664	240	991	326	182	394	5,797	21	0
21	DEMAND	3,747	2,174	114	891	323	181	43	3,726	21	0
22	CUSTOMER	2,071	1,490	126	100	3	1	351	2,071	0	0
23	TOTAL CWIP - WORK NOT BEARING INTEREST	33,847	15,090	799	5,543	2,255	2,479	490	26,656	634	6,557
24	DEMAND	30,972	13,217	652	5,244	2,184	2,376	128	23,781	634	6,557
25	CUSTOMER	2,071	1,490	126	100	3	1	351	2,071	0	0
26	ENERGY	804	383	21	199	88	102	11	804	0	0
	PLANT HELD FOR FUTURE USE										
27	PRODUCTION	5,280	2,785	136	1,120	478	579	25	5,123	157	0
	RETAIL JURISDICTION										
28	DEMAND		2,596	126	1,023	435	529	20	4,729		
29	ENERGY		189	10	97	43	50	5	394		
	DISTRIBUTION										
30	DEMAND	14	9	0	3	1	1	0	14	0	0
31	CUSTOMER	8	5	1	1	0	0	1	8	0	0
32	TOTAL DISTRIBUTION	22	14	1	4	1	1	1	22	0	0
	GENERAL										
33	DEMAND	79	44	2	17	7	7	0	77	2	0
34	CUSTOMER	50	38	4	5	1	0	2	50	0	0
35	ENERGY	4	2	1	0	0	1	0	4	0	0
36	TOTAL GENERAL	133	84	7	22	8	8	2	131	2	0
37	TOTAL PLNT HELD FOR FUT. USE	5,435	2,883	144	1,146	487	588	28	5,276	159	0
38	DEMAND	4,979	2,649	128	1,043	443	537	20	4,820	159	0
39	CUSTOMER	58	43	5	6	1	0	3	58	0	0
40	ENERGY	398	191	11	97	43	51	5	398	0	0

GULF POWER COMPANY
12 MONTHS ENDING DECEMBER 31, 2014
12/13 DEMAND ALLOCATION - WITH MDS METHODOLOGY
SCHEDULE 2.50 - ANALYSIS OF OTHER RATE BASE ITEMS
($000'S)

LINE NO. (1)	DESCRIPTION (2)	TOTAL ELECTRIC SYSTEM (3)	RATE CLASS RESIDENTIAL (4)	RATE CLASS GS (5)	RATE CLASS GSD/GSDT (8)	RATE CLASS LP/LPT (7)	RATE CLASS MAJOR ACCTS (8)	RATE CLASS OS (9)	TOTAL RETAIL SERVICE (10)	WHOLESALE (11)	UNIT POWER SALES (12)
	INJURIES & DAMAGES RESERVE										
41	PRODUCTION	(1,626)	(804)	(40)	(324)	(139)	(167)	(8)	(1,482)	(46)	(98)
	RETAIL JURISDICTION										
42	DEMAND		(750)	(37)	(296)	(126)	(153)	(6)	(1,368)		
43	ENERGY		(54)	(3)	(28)	(13)	(14)	(2)	(114)		
44	TRANSMISSION	(134)	(72)	(3)	(28)	(12)	(14)	(1)	(130)	(4)	0
45	DISTRIBUTION	(715)	(483)	(32)	(110)	(32)	(13)	(44)	(714)	(1)	0
46	DEMAND	(381)	(225)	(12)	(93)	(32)	(13)	(5)	(380)	(1)	0
47	CUSTOMER	(334)	(258)	(20)	(17)	0	0	(39)	(334)	0	0
48	CUSTOMER ACCOUNTS	(428)	(374)	(28)	(17)	0	0	(6)	(425)	(3)	0
49	CUSTOMER ASSISTANCE	(451)	(294)	(60)	(76)	(11)	(10)	0	(451)	0	0
50	CUSTOMER	(451)	(294)	(60)	(76)	(11)	(10)	0	(451)	0	0
51	ENERGY	0	0	0	0	0	0	0	0	0	0
52	TOTAL INJ. & DAM. RES.	(3,354)	(2,027)	(163)	(555)	(194)	(204)	(59)	(3,202)	(54)	(98)
53	DEMAND	(2,027)	(1,047)	(52)	(417)	(170)	(180)	(12)	(1,878)	(51)	(98)
54	CUSTOMER	(1,213)	(928)	(108)	(110)	(11)	(10)	(45)	(1,210)	(3)	0
55	ENERGY	(114)	(54)	(3)	(28)	(13)	(14)	(2)	(114)	0	0
	UNAMORT. PLANT ACQ. ADJ.										
56	PRODUCTION	1,852	0	0	0	0	0	0	0	0	1,852
	RETAIL JURISDICTION										
57	DEMAND		0	0	0	0	0	0	0		
58	ENERGY		0	0	0	0	0	0	0		
59	TRANSMISSION	51	0	0	0	0	0	0	0	0	51
60	DISTRIBUTION	0	0	0	0	0	0	0	0	0	0
61	DEMAND	0	0	0	0	0	0	0	0	0	0
62	CUSTOMER	0	0	0	0	0	0	0	0	0	0
63	TOTAL UNAMORT PLNT ACQ. ADJ.	1,903	0	0	0	0	0	0	0	0	1,903
64	DEMAND	1,903	0	0	0	0	0	0	0	0	1,903
65	CUSTOMER	0	0	0	0	0	0	0	0	0	0
66	ENERGY	0	0	0	0	0	0	0	0	0	0
67	CUSTOMER ADVANCES FOR CONST.	0	0	0	0	0	0	0	0	0	0
68	TOTAL OTHER ADDITIONS	37,831	15,946	780	6,134	2,548	2,863	459	28,730	739	6,362
69	DEMAND	35,827	14,619	728	5,870	2,437	2,733	136	26,723	742	6,362
70	CUSTOMER	916	607	23	(4)	(7)	(9)	309	919	(3)	0
71	ENERGY	1,088	520	29	268	116	139	14	1,088	0	0

GULF POWER COMPANY
12 MONTHS ENDED DECEMBER 31, 2014
12/13 DEMAND ALLOCATION - WITH MDS METHODOLOGY
ANALYSIS OF OTHER RATE BASE ITEMS

Line No.	Ftnt Label	Description
1	(A)	Functional totals provided by Gulf Power Company. Allocated per corresponding Gross Plant excluding UPS; UPS directly assigned.
2	(B)	Functional totals provided by Gulf Power Company. Allocated per corresponding Gross Plant.
3	(B)	
4	(B)	
5	(B)	
6	(B)	
7	(B)	
8	(C)	Allocated per corresponding Operations and Maintenance expense.
9	(C)	
10	(C)	
11	(C)	
16	(A)	
17	(B)	
18	(B)	
19	(B)	
20	(B)	
21	(B)	
22	(B)	
27	(B)	
28	(B)	
29	(B)	
30	(B)	
31	(B)	
33	(B)	
34	(B)	
35	(B)	
41	(D)	Allocated per Total Salaries and Wages, including UPS Production Salaries and Wages of $2,434.
42	(E)	Allocated per corresponding Salaries and Wages.
43	(E)	
44	(D)	
45	(E)	
46	(E)	
47	(E)	
48	(E)	
49	(E)	
50	(E)	
51	(E)	
56	(A)	
57	(B)	
58	(B)	
59	(A)	
60	(B)	
61	(B)	
62	(B)	
67	(F)	Specific Assignment.

GULF POWER COMPANY
12 MONTHS ENDING DECEMBER 31, 2014
12/13 DEMAND ALLOCATION - WITH MDS METHODOLOGY
SCHEDULE 3.00 - ANALYSIS OF REVENUES
($000'S)

LINE NO. (1)	DESCRIPTION (2)	TOTAL ELECTRIC SYSTEM (3)	RATE CLASS RESIDENTIAL (4)	RATE CLASS GS (5)	RATE CLASS GSD/GSDT (8)	RATE CLASS LP/LPT (7)	RATE CLASS MAJOR ACCTS (8)	RATE CLASS OS (9)	TOTAL RETAIL SERVICE (10)	WHOLESALE (11)	UNIT POWER SALES (12)
	REVENUE FROM SALES										
1	BASE RATE REV. FROM SALES	510,734	296,890	20,537	102,785	33,933	29,452	14,896	498,493	12,241	0
2	FUEL, ECCR, PPCC, ECRC REVENUES	0	0	0	0	0	0	0	0	0	0
3	NET REVENUE EXCLUDING FUEL	510,734	296,890	20,537	102,785	33,933	29,452	14,896	498,493	12,241	0
	OTHER OPERATING REVENUES										
	451-MISC. SERVICE REVENUES										
4	RESTORATION FEE	1,213	1,174	31	8	0	0	0	1,213	0	0
5	AFTER HOURS FEE	116	115	1	0	0	0	0	116	0	0
6	INACCURATE METER FEE	26	19	2	5	0	0	0	26	0	0
7	RECONNECTION FEE	2,823	2,696	64	43	0	0	0	2,823	0	0
8	FRANCHISE FEES	42,247	25,162	1,740	8,711	2,876	2,496	1,262	42,247	0	0
9	INSTALL. & REM.-TEMP SERV	0	0	0	0	0	0	0	0	0	0
10	CONNECTION FEES	92	77	13	2	0	0	0	92	0	0
11	COLLECTION CHARGES	207	181	24	22	0	0	0	207	0	0
12	INVESTIGATIVE CHARGES	40	38	2	0	0	0	0	40	0	0
13	RETURN CHECK CHARGE	272	258	6	8	0	0	0	272	0	0
14	TOTAL ACCOUNT 451	47,036	29,700	1,903	8,799	2,878	2,496	1,262	47,036	0	0
	454-RENT FROM ELEC. PROP.										
15	EQUIPMENT RENTAL	1,686	1,045	57	435	119	3	27	1,686	0	0
16	METER TREATER RENTAL	253	244	7	2	0	0	0	253	0	0
17	POLE ATTACHMENT RENTAL	3,110	2,411	169	343	91	32	64	3,110	0	0
18	MICROWAVE TRANSPORT	730	453	37	124	44	47	13	718	12	0
19	RENT FROM PLANT DANIEL	40	22	1	8	4	4	0	39	1	0
20	MISCELLANEOUS RENTS	518	321	26	88	31	33	9	508	8	0
21	TOTAL ACCOUNT 454	8,335	4,496	297	1,000	289	119	113	8,314	21	0
22	455-INTERDEPART. RENTAL	0	0	0	0	0	0	0	0	0	0
23	456-OTHER ELECTRIC REVENUES	8,368	3,390	165	1,336	569	692	26	8,178	190	0
24	456-GULF POWER ENERGY SERVICES REVENUES	5,632	0	0	0	5,632	0	0	5,632	0	0
25	456 - FPU SERVICE PAYMENTS	3,676	0	0	0	0	0	0	0	3,878	0
26	456 - BLOUNTSTOWN SERVICE PAYMENTS	122	65	3	26	11	13	0	118	4	0
27	TOTAL ACCOUNT 456	15,800	3,455	168	1,362	8,212	705	26	11,928	3,872	0
28	REV. NONASSOC. CO.-DEMAND	51,950	0	0	0	0	0	0	0	0	51,950
29	REV. NONASSOC. CO.-ENERGY	13,652	3,389	188	1,760	784	907	99	7,127	214	6,311
30	TOTAL REV. NONASSOC. CO.	65,602	3,389	188	1,760	784	907	99	7,127	214	58,261
31	TOTAL OTHER OPER. REVENUE	134,773	41,040	2,556	12,921	10,181	4,227	1,500	72,405	4,107	58,261
	ADJUSTMENTS TO REVENUES										
32	FRANCHISE FEE REVENUES	(42,247)	(25,162)	(1,740)	(8,711)	(2,878)	(2,496)	(1,262)	(42,247)	(0)	0
33	NET ADJUSTMENT TO REVENUES	(42,247)	(25,162)	(1,740)	(8,711)	(2,876)	(2,498)	(1,262)	(42,247)	(0)	0
34	TOTAL ADJUSTED REVENUES	603,260	312,768	21,353	106,995	41,218	31,183	15,134	528,651	18,348	58,261

GULF POWER COMPANY
12 MONTHS ENDED DECEMBER 31, 2014
12/13 DEMAND ALLOCATION - WITH MDS METHODOLOGY
ANALYSIS OF REVENUES

Line No.	Ftnt Label	Description
1	(A)	Provided by Gulf Power Company.
2	(B)	Allocated per Retail MWH Sales.
4	(A)	
5	(A)	
6	(A)	
7	(A)	
8	(C)	Allocated per retail revenue from sales.
9	(A)	
10	(A)	
11	(A)	
12	(A)	
13	(A)	
15	(D)	Allocated per Level 5 Demand Allocator
16	(A)	
17	(E)	Allocated per Distribution Gross Plant in Account 364.
18	(F)	Allocated per Total Salaries and Wages.
19	(G)	Allocated per Level 2 Demand Allocator; UPS directly assigned.
20	(F)	
22	(F)	
23	(G)	
24	(H)	Provided by Gulf Power Company and assigned to Rate Class LP/LPT.
25	(I)	Assigned to FPU.
26	(G)	
28	(G)	
29	(J)	Allocated per Level 1 Energy Allocator; UPS directly assigned.
32	(C)	

GULF POWER COMPANY
12 MONTHS ENDING DECEMBER 31, 2014
12/13 DEMAND ALLOCATION - WITH MDS METHODOLOGY
SCHEDULE 4.10 - ANALYSIS OF OPERATIONS AND MAINTENANCE EXPENSE
($000'S)

LINE NO. (1)	DESCRIPTION (2)	TOTAL ELECTRIC SYSTEM (3)	RATE CLASS RESIDENTIAL (4)	RATE CLASS GS (5)	RATE CLASS GSD/GSDT (6)	RATE CLASS LP/LPT (7)	RATE CLASS MAJOR ACCTS (8)	RATE CLASS OS (9)	TOTAL RETAIL SERVICE (10)	WHOLESALE (11)	UNIT POWER SALES (12)
	PRODUCTION O & M EXPENSES										
	STEAM POWER GENERATION										
	OPERATIONS										
1	500-SUPERVISION	11,719	6,087	297	2,400	1,021	1,244	47	11,096	341	282
2	501-ENERGY RELATED	310,061	127,134	7,034	66,006	29,382	33,974	3,709	267,239	8,028	34,814
3	501-FUEL REMOVAL	(303,538)	(124,330)	(6,879)	(64,550)	(28,734)	(33,224)	(3,627)	(261,344)	(7,851)	(34,343)
4	501-NET	6,543	2,804	155	1,456	648	750	82	5,895	177	471
	502-STEAM										
5	DEMAND RELATED	2,508	1,171	57	462	197	240	9	2,136	66	306
6	ENERGY RELATED	5,763	2,193	121	1,139	507	586	64	4,610	139	1,014
7	TOTAL ACCOUNT 502	8,271	3,364	178	1,601	704	826	73	6,746	205	1,320
	505-ELECTRIC EXPENSES										
8	DEMAND RELATED	2,946	1,472	72	580	247	301	11	2,683	82	181
9	ENERGY RELATED	1,185	533	30	278	124	143	16	1,124	34	27
10	TOTAL ACCOUNT 505	4,131	2,005	102	858	371	444	27	3,807	116	208
	506-MISCELLANEOUS										
11	DEMAND RELATED	15,224	7,666	374	3,022	1,286	1,565	59	13,972	429	823
12	ENERGY RELATED	0	0	0	0	0	0	0	0	0	0
13	TOTAL ACCOUNT 506	15,224	7,666	374	3,022	1,286	1,565	59	13,972	429	823
14	507-RENTS	0	0	0	0	0	0	0	0	0	0
15	509-ALLOWANCES	0	0	0	0	0	0	0	0	0	0
16	TOTAL STEAM OPERATIONS	46,888	21,926	1,106	9,337	4,030	4,829	288	41,516	1,268	3,104
	MAINTENANCE										
17	510-SUPERVISION	9,888	4,915	240	1,938	825	1,004	38	8,960	275	651
18	511-STRUCTURES	5,707	2,864	139	1,128	480	584	22	5,217	160	330
	512-BOILER PLANT										
19	DEMAND RELATED	3,490	1,577	77	622	265	322	12	2,875	88	527
20	ENERGY RELATED	25,255	9,588	531	4,979	2,216	2,562	280	20,156	606	4,493
21	TOTAL ACCOUNT 512	28,745	11,165	608	5,601	2,481	2,884	292	23,031	694	5,020
	513-ELECTRIC PLANT										
22	DEMAND RELATED	1,340	701	34	276	118	144	5	1,278	39	23
23	ENERGY RELATED	7,097	2,962	164	1,538	684	791	86	6,225	187	685
24	TOTAL ACCOUNT 513	8,437	3,663	198	1,814	802	935	91	7,503	226	708

GULF POWER COMPANY
12 MONTHS ENDING DECEMBER 31, 2014
12/13 DEMAND ALLOCATION - WITH MDS METHODOLOGY
SCHEDULE 4.10 - ANALYSIS OF OPERATIONS AND MAINTENANCE EXPENSE
($000'S)

LINE NO. (1)	DESCRIPTION (2)	TOTAL ELECTRIC SYSTEM (3)	RATE CLASS RESIDENTIAL (4)	RATE CLASS GS (5)	RATE CLASS GSD/GSDT (6)	RATE CLASS LP/LPT (7)	RATE CLASS MAJOR ACCTS (8)	RATE CLASS OS (9)	TOTAL RETAIL SERVICE (10)	WHOLESALE (11)	UNIT POWER SALES (12)
	514-MISCELLANEOUS										
25	DEMAND RELATED	3,132	1,529	75	603	257	312	12	2,788	86	258
26	ENERGY RELATED	0	0	0	0	0	0	0	0	0	0
27	TOTAL ACCOUNT 514	3,132	1,529	75	603	257	312	12	2,788	86	258
28	TOTAL MAINTENANCE	55,907	24,136	1,260	11,084	4,845	5,719	455	47,499	1,441	6,967
29	TOTAL STEAM POWER GENERATION	101,795	46,062	2,366	20,421	8,875	10,548	743	89,015	2,709	10,071
	OTHER POWER GENERATION										
	OPERATION										
30	546-SUPERVISION	1,701	905	44	357	152	185	7	1,650	51	0
31	547-ENERGY RELATED	580	267	15	139	62	72	8	563	17	0
32	547-FUEL	310,241	143,287	7,928	74,392	33,115	38,291	4,180	301,193	9,048	0
33	547-FUEL REMOVAL	(310,241)	(143,287)	(7,928)	(74,392)	(33,115)	(38,291)	(4,180)	(301,193)	(9,048)	0
34	547-NET FUEL	0	0	0	0	0	0	0	0	0	0
	548-GENERATION EXPENSES										
35	DEMAND	528	281	14	111	47	57	2	512	16	0
36	ENERGY	0	0	0	0	0	0	0	0	0	0
37	TOTAL ACCOUNT 548	528	281	14	111	47	57	2	512	16	0
	549-MISCELLANEOUS PLANT										
38	DEMAND	848	452	22	178	76	92	3	823	25	0
39	ENERGY	0	0	0	0	0	0	0	0	0	0
40	TOTAL ACCOUNT 549	848	452	22	178	76	92	3	823	25	0
41	TOTAL OPERATION	3,657	1,905	95	785	337	406	20	3,548	109	0
	MAINTENANCE										
42	551-SUPERVISION	296	157	8	62	26	33	1	287	9	0
	552-STRUCTURES										
43	DEMAND	0	0	0	0	0	0	0	0	0	0
44	ENERGY	0	0	0	0	0	0	0	0	0	0
45	TOTAL ACCOUNT 552	0	0	0	0	0	0	0	0	0	0

GULF POWER COMPANY
12 MONTHS ENDING DECEMBER 31, 2014
12/13 DEMAND ALLOCATION - WITH MDS METHODOLOGY
SCHEDULE 4.10 - ANALYSIS OF OPERATIONS AND MAINTENANCE EXPENSE
($000'S)

LINE NO. (1)	DESCRIPTION (2)	TOTAL ELECTRIC SYSTEM (3)	RATE CLASS RESIDENTIAL (4)	RATE CLASS GS (5)	RATE CLASS GSD/GSDT (6)	RATE CLASS LP/LPT (7)	RATE CLASS MAJOR ACCTS (8)	RATE CLASS OS (9)	TOTAL RETAIL SERVICE (10)	WHOLESALE (11)	UNIT POWER SALES (12)
	553-ELECTRIC PLANT										
46	DEMAND	6,665	3,547	173	1,399	595	725	27	6,466	199	0
47	ENERGY	0	0	0	0	0	0	0	0	0	0
48	TOTAL ACCOUNT 553	6,665	3,547	173	1,399	595	725	27	6,466	199	0
	554-MISCELLANEOUS PLANT										
49	DEMAND	524	278	14	110	47	57	2	508	16	0
50	ENERGY	0	0	0	0	0	0	0	0	0	0
51	TOTAL ACCOUNT 554	524	278	14	110	47	57	2	508	16	0
52	TOTAL MAINTENANCE	7,485	3,982	195	1,571	668	815	30	7,261	224	0
53	TOTAL OTHER GEN. EXPENSE	11,142	5,887	290	2,356	1,005	1,221	50	10,809	333	0
54	TOTAL GENERATION EXPENSES	112,937	51,949	2,656	22,777	9,880	11,769	793	99,824	3,042	10,071
55	DEMAND	66,514	33,602	1,640	13,248	5,639	6,865	257	61,251	1,882	3,381
56	ENERGY	46,423	18,347	1,016	9,529	4,241	4,904	536	38,573	1,160	6,690
	OTHER PRODUCTION EXPENSE										
57	555-PURCHASED POWER	35,992	15,276	845	7,932	3,531	4,083	446	32,113	965	2,914
58	DEMAND	0	0	0	0	0	0	0	0	0	0
59	ENERGY	35,992	15,276	845	7,932	3,531	4,083	446	32,113	965	2,914
60	FUEL REMOVAL	(35,992)	(15,276)	(845)	(7,932)	(3,531)	(4,083)	(446)	(32,113)	(965)	(2,914)
61	NET ENERGY	0	0	0	0	0	0	0	0	0	0
62	NET TOTAL ACCOUNT 555	0	0	0	0	0	0	0	0	0	0
	556-SYSTEM CONTROL										
63	DEMAND	1,617	968	47	381	162	198	7	1,763	54	0
64	ENERGY	0	0	0	0	0	0	0	0	0	0
65	TOTAL ACCOUNT 556	1,817	968	47	381	162	198	7	1,763	54	0
	557-OTHER EXPENSES										
66	DEMAND	2,054	1,095	53	431	183	223	8	1,993	61	0
67	ENERGY	0	0	0	0	0	0	0	0	0	0
68	TOTAL ACCOUNT 557	2,054	1,095	53	431	183	223	8	1,993	61	0
69	TOTAL OTHER PROD. EXPENSE	3,871	2,063	100	812	345	421	15	3,756	115	0
70	DEMAND	3,871	2,063	100	812	345	421	15	3,756	115	0
71	ENERGY	0	0	0	0	0	0	0	0	0	0
72	TOTAL PRODUCTION EXPENSES	116,808	54,012	2,756	23,589	10,225	12,190	808	103,580	3,157	10,071
73	DEMAND	70,385	35,665	1,740	14,060	5,984	7,286	272	65,007	1,997	3,381
74	ENERGY	46,423	18,347	1,016	9,529	4,241	4,904	536	38,573	1,160	6,690

GULF POWER COMPANY
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12/13 DEMAND ALLOCATION - WITH MDS METHODOLOGY
SCHEDULE 4.10 - ANALYSIS OF OPERATIONS AND MAINTENANCE EXPENSE
($000'S)

LINE NO. (1)	DESCRIPTION (2)	TOTAL ELECTRIC SYSTEM (3)	RATE CLASS RESIDENTIAL (4)	RATE CLASS GS (5)	RATE CLASS GSD/GSDT (6)	RATE CLASS LP/LPT (7)	RATE CLASS MAJOR ACCTS (8)	RATE CLASS OS (9)	TOTAL RETAIL SERVICE (10)	WHOLESALE (11)	UNIT POWER SALES (12)
	TRANSMISSION O & M EXPENSE										
	OPERATION										
75	561-LOAD DISPATCHING	3,526	1,877	91	739	315	383	14	3,419	105	2
76	562-STATION	43	24	1	9	4	4	0	42	1	0
77	563-OVERHEAD LINES	191	101	5	40	17	21	1	185	6	0
78	564-UNDERGROUND LINES	0	0	0	0	0	0	0	0	0	0
79	565-TRANS. OF ELEC. BY OTHERS	(301)	(160)	(8)	(63)	(27)	(33)	(1)	(292)	(9)	0
80	SUBTOTAL	3,459	1,842	89	725	309	375	14	3,354	103	2
81	560-SUPERVISION	1,609	856	41	337	144	175	7	1,560	48	1
82	566-MISCELLANEOUS	1,038	552	27	217	93	113	4	1,006	31	1
83	567-RENTS	165	87	4	35	15	18	1	160	5	0
84	TOTAL OPERATIONS	8,271	3,337	161	1,314	561	681	26	6,080	187	4
	MAINTENANCE										
85	569-STRUCTURES	1,003	533	26	211	90	109	4	973	30	0
86	570-STATION EQUIPMENT	830	454	22	179	74	79	3	811	19	0
87	571-OVERHEAD LINES	4,479	2,385	116	940	400	486	18	4,345	134	0
88	SUBTOTAL	6,312	3,372	164	1,330	564	674	25	6,129	183	0
89	568-SUPERVISION	1,052	561	27	222	94	113	4	1,021	31	0
90	573-MISCELLANEOUS	102	56	3	21	9	10	0	99	3	0
91	TOTAL MAINTENANCE	7,486	3,989	194	1,573	667	797	29	7,249	217	0
92	TOTAL TRANSMISSION EXPENSE	13,737	7,326	355	2,887	1,228	1,478	55	13,329	404	4
	DISTRIBUTION O & M EXPENSE										
	OPERATIONS										
93	581-LOAD DISPATCHING	902	536	26	211	78	47	4	902	0	0
94	582-STATION	308	166	8	66	30	32	1	303	5	0

GULF POWER COMPANY
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12/13 DEMAND ALLOCATION - WITH MDS METHODOLOGY
SCHEDULE 4.10 - ANALYSIS OF OPERATIONS AND MAINTENANCE EXPENSE
($000'S)

LINE NO. (1)	DESCRIPTION (2)	TOTAL ELECTRIC SYSTEM (3)	RATE CLASS RESIDENTIAL (4)	RATE CLASS GS (5)	RATE CLASS GSD/GSDT (6)	RATE CLASS LP/LPT (7)	RATE CLASS MAJOR ACCTS (8)	RATE CLASS OS (9)	TOTAL RETAIL SERVICE (10)	WHOLESALE (11)	UNIT POWER SALES (12)
	583-OVERHEAD LINES										
95	DEMAND	2,006	1,215	66	505	156	33	31	2,006	0	0
96	CUSTOMER	573	500	37	23	0	0	13	573	0	0
97	TOTAL ACCOUNT 583	2,579	1,715	103	528	156	33	44	2,579	0	0
	584-UNDERGROUND LINES										
98	DEMAND	608	368	20	154	47	10	9	608	0	0
99	CUSTOMER	131	115	9	4	0	0	3	131	0	0
100	TOTAL ACCOUNT 584	739	483	29	158	47	10	12	739	0	0
101	585-STREET LIGHTING	598	0	0	0	0	0	598	598	0	0
102	586-METER	1,453	1,090	144	196	11	6	3	1,450	3	0
103	586-OTHER MISC. REVS.	1,174	1,118	38	18	0	0	0	1,174	0	0
104	TOTAL ACCOUNT 586	2,627	2,208	182	214	11	6	3	2,624	3	0
105	587-CUSTOMER INSTAL.	1,306	1,164	68	53	1	0	0	1,306	0	0
106	587-OTHER MISC. REVS.	25	24	1	0	0	0	0	25	0	0
107	TOTAL ACCOUNT 587	1,331	1,188	89	53	1	0	0	1,331	0	0
108	SUBTOTAL	9,084	6,296	437	1,230	323	128	662	9,076	8	0
109	DEMAND	3,824	2,285	120	936	311	122	45	3,819	5	0
110	CUSTOMER	5,260	4,011	317	294	12	6	617	5,257	3	0
	580-SUPERVISION										
111	DEMAND	2,849	1,702	89	697	232	91	34	2,845	4	0
112	CUSTOMER	3,919	2,989	236	219	9	4	460	3,917	2	0
113	TOTAL ACCOUNT 580	6,768	4,691	325	916	241	95	494	6,762	6	0
	588-MISCELLANEOUS										
114	DEMAND	1,837	1,099	58	449	149	58	22	1,835	2	0
115	CUSTOMER	2,526	1,928	152	141	6	2	296	2,525	1	0
116	TOTAL ACCOUNT 588	4,363	3,027	210	590	155	60	318	4,360	3	0
	589-RENTS										
117	DEMAND	0	0	0	0	0	0	0	0	0	0
118	CUSTOMER	0	0	0	0	0	0	0	0	0	0
119	TOTAL ACCOUNT 589	0	0	0	0	0	0	0	0	0	0
120	TOTAL OPERATION	20,215	14,014	972	2,736	719	283	1,474	20,198	17	0
	MAINTENANCE										
121	591-STRUCTURES	28	15	1	6	3	2	0	27	1	0
122	592-STATION EQUIPMENT	962	518	25	205	94	100	4	946	16	0

GULF POWER COMPANY
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12/13 DEMAND ALLOCATION - WITH MDS METHODOLOGY
SCHEDULE 4.10 - ANALYSIS OF OPERATIONS AND MAINTENANCE EXPENSE
($000'S)

LINE NO. (1)	DESCRIPTION (2)	TOTAL ELECTRIC SYSTEM (3)	RATE CLASS RESIDENTIAL (4)	RATE CLASS GS (5)	RATE CLASS GSD/GSDT (6)	RATE CLASS LP/LPT (7)	RATE CLASS MAJOR ACCTS (8)	RATE CLASS OS (9)	TOTAL RETAIL SERVICE (10)	WHOLESALE (11)	UNIT POWER SALES (12)
123	593-OVHD LINES - MISC REVS	0	0	0	0	0	0	0	0	0	0
	593-OVERHEAD LINES										
124	DEMAND	7,747	4,582	248	1,913	855	231	118	7,747	0	0
125	CUSTOMER	5,328	4,641	350	210	3	0	124	5,328	0	0
126	SUBTOTAL OVERHEAD LINES	13,075	9,223	598	2,123	658	231	242	13,075	0	0
127	TOTAL ACCOUNT 593	13,075	9,223	598	2,123	658	231	242	13,075	0	0
	594-UNDERGROUND LINES										
128	DEMAND	1,810	1,075	58	449	151	49	28	1,810	0	0
129	CUSTOMER	87	76	6	3	0	0	2	87	0	0
130	TOTAL ACCOUNT 594	1,897	1,151	64	452	151	49	30	1,897	0	0
	595-LINE TRANSFORMERS										
131	DEMAND	747	458	25	191	55	6	12	747	0	0
132	CUSTOMER	254	222	16	10	0	0	6	254	0	0
133	TOTAL ACCOUNT 595	1,001	680	41	201	55	6	18	1,001	0	0
134	596-STREET LIGHTING	597	0	0	0	0	0	597	597	0	0
135	597-METERS	159	121	16	21	1	0	0	159	0	0
136	SUBTOTAL	17,719	11,708	745	3,008	962	388	891	17,702	17	0
137	DEMAND	11,294	6,648	357	2,764	958	388	162	11,277	17	0
138	CUSTOMER	6,425	5,060	388	244	4	0	729	6,425	0	0
	590-SUPERVISION										
139	DEMAND	2,335	1,376	74	571	198	79	33	2,331	4	0
140	CUSTOMER	1,329	1,047	80	50	1	0	151	1,329	0	0
141	TOTAL ACCOUNT 590	3,664	2,423	154	621	199	79	184	3,660	4	0
	598-MISCELLANEOUS										
142	DEMAND	301	177	10	74	26	10	4	301	0	0
143	CUSTOMER	171	136	10	6	0	0	19	171	0	0
144	TOTAL ACCOUNT 598	472	313	20	80	26	10	23	472	0	0
145	TOTAL MAINTENANCE	21,855	14,444	919	3,709	1,187	477	1,098	21,834	21	0
146	TOTAL DISTRIBUTION EXPENSE	42,070	28,458	1,891	6,445	1,906	760	2,572	42,032	38	0
147	TOTAL DEMAND	22,440	13,287	708	5,491	1,874	748	300	22,408	32	0
148	TOTAL CUSTOMER	19,630	15,171	1,183	954	32	12	2,272	19,624	6	0
149	CUSTOMER ACCOUNTS EXPENSE	21,986	19,131	1,446	869	22	38	301	21,807	179	0

GULF POWER COMPANY
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	CUSTOMER ASSISTANCE EXPENSE										
150	907/911-SUPERVISION	1,829	1,603	141	84	1	0	0	1,829	0	0
	908/912-CUSTOMER ASSISTANCE										
151	RESIDENTIAL	5,080	5,080	0	0	0	0	0	5,080	0	0
152	COMMERCIAL	2,093	0	1,305	776	11	1	0	2,093	0	0
153	TOTAL INDUSTRIAL	7,391	0	145	1,121	5,874	251	0	7,391	0	0
154	INDUSTRIAL - GULF POWER ENERGY SRVS	5,597	0	0	0	5,597	0	0	5,597	0	0
155	NET INDUSTRIAL OF GULF POWER ENERGY SRVS	1,794	0	145	1,121	277	251	0	1,794	0	0
156	STREET LIGHTING	0	0	0	0	0	0	0	0	0	0
157	TOTAL ACCOUNT 908/912	14,564	5,080	1,450	1,897	5,885	252	0	14,564	0	0
158	909/913-ADVERTISING	1,232	1,125	13	65	15	14	0	1,232	0	0
159	910-MISCELLANEOUS	190	165	15	9	0	0	0	190	0	0
160	ENERGY CONSERVATION	21,933	19,377	1,357	1,058	78	63	0	21,933	0	0
161	ECCR ADJUSTMENT	(21,933)	(19,377)	(1,357)	(1,058)	(78)	(63)	0	(21,933)	0	0
162	NET ENERGY COST CONSER.	0	0	0	0	0	0	0	0	0	0
163	TOTAL CUSTOMER ASSISTANCE	17,815	7,974	1,619	2,055	5,901	266	0	17,815	0	0
	ADMIN. & GENERAL EXPENSE										
	924-PROPERTY INSURANCE										
164	PRODUCTION	4,309	2,147	105	863	368	446	19	3,948	128	233
	RETAIL JURISDICTION										
165	DEMAND		2,001	97	788	335	408	15	3,644		
166	ENERGY		146	8	75	33	38	4	304		
167	TRANSMISSION	1,782	957	47	377	159	186	7	1,733	49	0
168	DISTRIBUTION	7,228	4,552	298	1,231	405	226	489	7,201	27	0
169	DEMAND	4,655	2,702	141	1,107	401	224	54	4,629	26	0
170	CUSTOMER	2,573	1,850	157	124	4	2	435	2,572	1	0
171	CUSTOMER ACCOUNTS	72	62	5	3	0	0	1	71	1	0
172	CUSTOMER ASSISTANCE	76	34	7	9	25	1	0	76	0	0
173	CUSTOMER	76	34	7	9	25	1	0	76	0	0
174	ENERGY	0	0	0	0	0	0	0	0	0	0
175	TOTAL ACCOUNT 924	13,467	7,752	462	2,483	957	859	516	13,029	205	233
176	DEMAND	10,442	5,660	285	2,272	895	818	76	10,006	203	233
177	CUSTOMER	2,721	1,946	169	136	29	3	436	2,719	2	0
178	ENERGY	304	146	8	75	33	38	4	304	0	0
	REG. COMM. EXP. & UNCOLL.										
179	STATE & FEDERAL	3,171	1,568	108	543	179	155	79	2,632	539	0
180	UNCOLLECTIBLE EXP.	3,809	3,401	256	149	3	0	0	3,809	0	0
181	TOTAL REG. COMM. & UNCOLL.	6,980	4,969	364	692	182	155	79	6,441	539	0
182	OTHER INDUSTRY DUES	705	332	18	173	78	94	10	705	0	0

GULF POWER COMPANY
12 MONTHS ENDING DECEMBER 31, 2014
12/13 DEMAND ALLOCATION - WITH MDS METHODOLOGY
SCHEDULE 4.10 - ANALYSIS OF OPERATIONS AND MAINTENANCE EXPENSE
($000'S)

LINE NO. (1)	DESCRIPTION (2)	TOTAL ELECTRIC SYSTEM (3)	RATE CLASS RESIDENTIAL (4)	RATE CLASS GS (5)	RATE CLASS GSD/GSDT (6)	RATE CLASS LP/LPT (7)	RATE CLASS MAJOR ACCTS (8)	RATE CLASS OS (9)	TOTAL RETAIL SERVICE (10)	WHOLESALE (11)	UNIT POWER SALES (12)
183	MISC. A & G - OTHER REVS.	2	2	0	0	0	0	0	2	0	0
184	MISC. A & G - GULF POWER ENERGY SRVC OH	36	0	0	0	36	0	0	36	0	0
185	MISCELLANEOUS A & G	75,002	45,211	3,638	12,369	4,337	4,587	1,281	71,423	1,195	2,384
186	DEMAND	45,401	23,371	1,161	9,308	3,786	4,023	253	41,902	1,115	2,384
187	CUSTOMER	27,059	20,632	2,411	2,432	272	240	992	26,979	80	0
188	ENERGY	2,542	1,208	66	629	279	324	36	2,542	0	0
189	TOTAL MISCELLANEOUS A & G	75,040	45,213	3,638	12,369	4,373	4,587	1,281	71,461	1,195	2,384
190	DEMAND	45,401	23,371	1,161	9,308	3,786	4,023	253	41,902	1,115	2,384
191	CUSTOMER	27,097	20,634	2,411	2,432	308	240	992	27,017	80	0
192	ENERGY	2,542	1,208	66	629	279	324	36	2,542	0	0
193	TOTAL ADMIN. & GENERAL	96,192	58,266	4,482	15,717	5,590	5,695	1,886	91,636	1,939	2,617
194	TOTAL OPER. & MAINTENANCE	308,608	175,167	12,549	51,562	24,872	20,427	5,622	290,199	5,717	12,692
195	DEMAND	162,405	85,309	4,249	34,018	13,767	14,353	956	152,652	3,751	6,002
196	ENERGY	49,974	20,033	1,108	10,406	4,631	5,360	586	42,124	1,160	6,690
197	CUSTOMER	89,249	64,856	6,828	6,446	6,292	559	4,001	88,982	267	0
198	REVENUE	6,980	4,969	364	692	182	155	79	6,441	539	0

GULF POWER COMPANY
12 MONTHS ENDED DECEMBER 31, 2014
12/13 DEMAND ALLOCATION - WITH MDS METHODOLOGY
ANALYSIS OF OPERATIONS AND MAINTENANCE EXPENSE

Line No.	Ftnt Label	Description
1	(A)	Allocated per Level 1 Demand Allocator; UPS directly assigned.
2	(B)	Allocated per Level 1 Energy Allocator; UPS directly assigned.
3	(B)	
5	(A)	
6	(B)	
8	(A)	
9	(B)	
11	(A)	
12	(B)	
14	(C)	Allocated per Level 2 Demand Allocator; UPS directly assigned.
15	(B)	
17	(A)	
18	(A)	
19	(A)	
20	(B)	
22	(A)	
23	(B)	
25	(A)	
26	(B)	
30	(D)	Allocated per Level 1 Demand Allocator.
31	(E)	Allocated per Level 1 Energy Allocator.
32	(E)	
33	(E)	
35	(D)	
36	(E)	
38	(D)	
39	(E)	
42	(D)	
43	(D)	
44	(E)	
46	(D)	
47	(E)	
49	(D)	
50	(E)	
58	(A)	
59	(B)	
60	(B)	

GULF POWER COMPANY
12 MONTHS ENDED DECEMBER 31, 2014
12/13 DEMAND ALLOCATION - WITH MDS METHODOLOGY
ANALYSIS OF OPERATIONS AND MAINTENANCE EXPENSE

Line No.	Ftnt Label	Description
63	(F)	Allocated per sum of Generation Demand Expenses and Purchased Power Demand Expenses.
64	(E)	
66	(D)	
67	(E)	
75	(C)	
76	(G)	Allocated per Transmission Substations Gross Plant; UPS directly assigned.
77	(H)	Allocated per Transmission Lines Gross Plant; UPS directly assigned.
78	(I)	Allocated per Transmission Account 358 Gross Plant.
79	(D)	
81	(J)	Allocated per Subtotal of Transmission Operations O & M Expense; UPS directly assigned.
82	(J)	
83	(J)	
85	(K)	Allocated per sum of Transmission Accounts 352, 354, and 355 Gross Plant; UPS directly assigned.
86	(L)	Allocated per Transmission Account 353 Gross Plant; UPS directly assigned.
87	(H)	
89	(M)	Allocated per Subtotal of Transmission Maintenance O & M Expense; UPS directly assigned.
90	(M)	
93	(N)	Allocated per Level 3 Demand Allocator.
94	(O)	Allocated per Distribution Substations Gross Plant.
95	(P)	Allocated per corresponding Distribution Gross Plant Accounts 365 and 368.
96	(P)	
98	(Q)	Allocated per corresponding Distribution Gross Plant Accounts 367 and 368.
99	(Q)	
101	(R)	Allocated per Distribution Account 373 Gross Plant.
102	(S)	Allocated per Distribution Account 370 Gross Plant.
103	(T)	Per analysis of information provided by Gulf Power Company.
105	(U)	Allocated per Distribution Account 369 Gross Plant.
106	(T)	
111	(V)	Allocated per corresponding Subtotal of Distribution Operations O & M.
112	(V)	
114	(V)	
115	(V)	

GULF POWER COMPANY
12 MONTHS ENDED DECEMBER 31, 2014
12/13 DEMAND ALLOCATION - WITH MDS METHODOLOGY
ANALYSIS OF OPERATIONS AND MAINTENANCE EXPENSE

Line No.	Ftnt Label	Description
117	(V)	
118	(V)	
121	(W)	Allocated per Distribution Account 361 Gross Plant.
122	(X)	Allocated per Distribution Account 362 Gross Plant.
123	(T)	
124	(Y)	Allocated per Common portion of Distribution Accounts 364 and 365.
125	(Z)	Allocated per Customer portion of Distribution Accounts 364 and 365.
128	(AA)	Allocated per Common portion of Distribution Accounts 366 and 367 Gross Plant.
129	(AB)	Allocated per Customer portion of Distribution Accounts 366 and 367 Gross Plant.
131	(AC)	Allocated per Distribution Account 368 Gross Plant.
132	(AC)	
134	(R)	
135	(S)	
139	(AD)	Allocated per corresponding Subtotal of Distribution Maintenance O & M.
140	(AD)	
142	(AD)	
143	(AD)	
149	(AE)	Direct assignment to rate provided by Gulf Power Company.
150	(AF)	Provided by Gulf Power to Class. Allocated to rate based on analysis of average number of customers within class.
151	(AF)	
152	(AF)	
153	(AF)	
154	(AG)	Provided by Gulf Power and assigned to Rate Class LP/LPT.
156	(AF)	
158	(AF)	
159	(AF)	
160	(AF)	
161	(AF)	

GULF POWER COMPANY
12 MONTHS ENDED DECEMBER 31, 2014
12/13 DEMAND ALLOCATION - WITH MDS METHODOLOGY
ANALYSIS OF OPERATIONS AND MAINTENANCE EXPENSE

Line No.	Ftnt Label	Description
164	(AH)	Retail jurisdiction sum of corresponding demand and energy pieces; Wholesale allocated per Level 1 Demand Allocator; UPS directly assigned.
165	(D)	
166	(E)	
167	(AI)	Allocated per Transmission Gross Plant; UPS directly assigned.
168	(AJ)	Allocated per corresponding Distribution Gross Plant.
169	(AJ)	
170	(AJ)	
171	(AK)	Allocated per Customer Accounts O & M Expense.
172	(AL)	Allocated per corresponding Customer Assistance O & M Expense.
173	(AL)	
174	(AL)	
179	(AM)	Provided by Gulf Power to jurisdiction. Allocated to rate per Retail Revenue from Sales.
180	(AE)	
182	(AN)	Allocated per Retail MWH Sales.
183	(T)	
184	(AO)	A&G Overheads related to Gulf Power Energy Services. Assigned to Rate Class LP/LPT.
185	(AP)	Allocated per corresponding Salaries and Wages; UPS directly assigned.
186	(AP)	
187	(AP)	
188	(AP)	

GULF POWER COMPANY
12 MONTHS ENDING DECEMBER 31, 2014
12/13 DEMAND ALLOCATION - WITH MDS METHODOLOGY
SCHEDULE 4.20 - ANALYSIS OF DEPRECIATION EXPENSE
($000'S)

LINE NO. (1)	DESCRIPTION (2)	TOTAL ELECTRIC SYSTEM (3)	RATE CLASS RESIDENTIAL (4)	RATE CLASS GS (5)	RATE CLASS GSD/GSDT (6)	RATE CLASS LP/LPT (7)	RATE CLASS MAJOR ACCTS (8)	RATE CLASS OS (9)	TOTAL RETAIL SERVICE (10)	WHOLESALE (11)	UNIT POWER SALES (12)
1	TOTAL PRODUCTION	52,105	23,360	1,149	9,405	4,018	4,867	213	43,012	1,322	7,771
	RETAIL JURISDICTION										
2	DEMAND		21,785	1,062	8,588	3,654	4,447	167	39,703		
3	ENERGY		1,575	87	817	364	420	46	3,309		
	TRANSMISSION										
4	350-LAND AND LAND RIGHTS	211	114	5	44	19	22	1	205	6	0
5	352-STRUCTURES	197	106	5	42	18	20	1	192	5	0
6	353-STATION EQUIPMENT	3,896	2,065	101	814	334	362	16	3,692	85	119
7	354-TOWERS & FIXTURES	767	408	20	161	68	84	3	744	23	0
8	355-POLES & FIXTURES	5,796	3,085	150	1,216	518	630	24	5,623	173	0
9	356-OVERHEAD COND.	2,138	1,138	55	449	191	232	9	2,074	64	0
10	358-UNDERGROUND COND.	254	134	7	53	23	28	1	246	8	0
11	359-ROADS AND TRAILS	5	3	0	1	0	1	0	5	0	0
12	TOTAL TRANSMISSION	13,264	7,053	343	2,780	1,171	1,379	55	12,781	364	119
	DISTRIBUTION										
13	360-SUBSTATION LAND	13	8	0	3	1	1	0	13	0	0
14	361-STRUCTURES	441	239	12	94	47	39	2	433	8	0
15	362-STATION EQUIPMENT	5,191	2,803	137	1,105	505	536	21	5,107	84	0
	364-POLES & FIXTURES										
16	COMMON	2,142	1,266	69	529	181	64	33	2,142	0	0
17	CUSTOMER	4,139	3,606	272	163	2	0	96	4,139	0	0
18	TOTAL ACCOUNT 364	6,281	4,872	341	692	183	64	129	6,281	0	0

GULF POWER COMPANY
12 MONTHS ENDING DECEMBER 31, 2014
12/13 DEMAND ALLOCATION - WITH MDS METHODOLOGY
SCHEDULE 4.20 - ANALYSIS OF DEPRECIATION EXPENSE
($000'S)

LINE NO. (1)	DESCRIPTION (2)	TOTAL ELECTRIC SYSTEM (3)	RATE CLASS RESIDENTIAL (4)	RATE CLASS GS (5)	RATE CLASS GSD/GSDT (6)	RATE CLASS LP/LPT (7)	RATE CLASS MAJOR ACCTS (8)	RATE CLASS OS (9)	TOTAL RETAIL SERVICE (10)	WHOLESALE (11)	UNIT POWER SALES (12)
	365-OVERHEAD COND.										
19	DEMAND	3,681	2,177	118	909	311	110	56	3,681	0	0
20	CUSTOMER	717	624	47	28	1	0	17	717	0	0
21	TOTAL ACCOUNT 365	4,398	2,801	165	937	312	110	73	4,398	0	0
	366-UNDG. CONDUIT										
22	COMMON	13	9	0	3	1	0	0	13	0	0
23	CUSTOMER	1	1	0	0	0	0	0	1	0	0
24	TOTAL ACCOUNT 366	14	10	0	3	1	0	0	14	0	0
	367-UNDERGROUND COND. & DEV.										
25	COMMON	4,325	2,570	139	1,072	360	118	66	4,325	0	0
26	CUSTOMER	208	181	14	8	0	0	5	208	0	0
27	TOTAL ACCOUNT 367	4,533	2,751	153	1,080	360	118	71	4,533	0	0
	368-LINE TRANSFORMERS										
28	COMMON	7,177	4,405	238	1,831	529	61	113	7,177	0	0
29	CUSTOMER	2,444	2,126	161	97	2	1	57	2,444	0	0
30	TOTAL ACCOUNT 368	9,621	6,531	399	1,928	531	62	170	9,621	0	0
31	369-SERVICES	2,838	2,531	191	114	2	0	0	2,838	0	0
32	370-METERS	4,485	3,367	443	604	34	19	10	4,477	8	0
33	373-STREET LIGHTING	2,871	0	0	0	0	0	2,871	2,871	0	0
34	TOTAL DISTRIBUTION	40,686	25,913	1,841	6,560	1,976	949	3,347	40,586	100	0
35	DEMAND	22,983	13,477	713	5,546	1,935	929	291	22,891	92	0
36	CUSTOMER	17,703	12,436	1,128	1,014	41	20	3,056	17,695	8	0
37	GENERAL PLANT	6,347	5,145	414	1,407	493	521	146	6,126	136	85
38	DEMAND	4,979	2,660	132	1,059	430	457	29	4,767	127	85
39	CUSTOMER	3,079	2,347	274	277	31	28	113	3,070	9	0
40	ENERGY	289	138	8	71	32	36	4	289	0	0
41	TOTAL DEPR. EXPENSE	114,402	61,471	3,747	20,152	7,658	7,716	3,761	104,505	1,922	7,975
42	DEMAND	90,022	44,975	2,250	17,973	7,190	7,212	542	80,142	1,905	7,975
43	CUSTOMER	20,782	14,783	1,402	1,291	72	48	3,169	20,765	17	0
44	ENERGY	3,598	1,713	95	888	396	456	50	3,598	0	0

GULF POWER COMPANY
12 MONTHS ENDED DECEMBER 31, 2014
12/13 DEMAND ALLOCATION - WITH MDS METHODOLOGY
ANALYSIS OF DEPRECIATION EXPENSE

Line No.	Ftnt Label	Description
1	(A)	Retail jurisdiction sum of Lines 2 and 3; Wholesale allocated per Level 1 Demand Allocator; UPS directly assigned.
2	(B)	Allocated per corresponding Level 1 Demand Allocator.
3	(C)	Allocated per corresponding Level 1 Energy Allocator.
4	(D)	Allocated per Transmission Account 350 Gross Plant (Lines portion only); UPS directly assigned.
5	(E)	Allocated per corresponding Transmission Gross Plant; UPS directly assigned.
6	(E)	
7	(E)	
8	(E)	
9	(E)	
10	(E)	
11	(E)	
13	(F)	Allocated per corresponding Distribution Gross Plant.
14	(F)	
15	(F)	
16	(F)	
17	(F)	
19	(F)	
20	(F)	
22	(F)	
23	(F)	
25	(F)	
26	(F)	
28	(F)	
29	(F)	
31	(F)	
32	(F)	
33	(F)	
37	(G)	Allocated per corresponding Gross General Plant; UPS directly assigned.
38	(G)	
39	(G)	
40	(G)	

GULF POWER COMPANY
12 MONTHS ENDING DECEMBER 31, 2014
12/13 DEMAND ALLOCATION - WITH MDS METHODOLOGY
SCHEDULE 4.30 - ANALYSIS OF TAXES OTHER THAN INCOME TAXES
($000'S)

LINE NO. (1)	DESCRIPTION (2)	TOTAL ELECTRIC SYSTEM (3)	RATE CLASS RESIDENTIAL (4)	RATE CLASS GS (5)	RATE CLASS GSD/GSDT (6)	RATE CLASS LP/LPT (7)	RATE CLASS MAJOR ACCTS (8)	RATE CLASS OS (9)	TOTAL RETAIL SERVICE (10)	WHOLESALE (11)	UNIT POWER SALES (12)
	REAL & PERSONAL PROPERTY										
1	PRODUCTION	17,196	8,587	422	3,456	1,477	1,789	78	15,809	486	901
	RETAIL JURISDICTION										
2	DEMAND		8,009	390	3,156	1,343	1,634	61	14,593		
3	ENERGY		578	32	300	134	155	17	1,216		
4	TRANSMISSION	2,598	1,389	68	547	230	268	11	2,513	71	14
5	DISTRIBUTION	5,968	3,759	246	1,017	334	186	404	5,946	22	0
6	DEMAND	3,843	2,230	117	914	331	186	45	3,823	21	0
7	CUSTOMER	2,124	1,529	129	103	3	0	359	2,123	1	0
8	CUSTOMER ACCOUNTS	120	104	8	5	0	0	2	119	1	0
9	CUSTOMER ASSISTANCE	128	57	12	15	42	2	0	128	0	0
10	CUSTOMER	128	57	12	15	42	2	0	128	0	0
11	ENERGY	0	0	0	0	0	0	0	0	0	0
12	TOTAL ELECTRIC PROP. TAXES	26,010	13,896	756	5,040	2,083	2,245	495	24,515	580	915
13	DEMAND	22,422	11,628	575	4,617	1,904	2,088	117	20,929	578	915
14	CUSTOMER	2,372	1,690	149	123	45	2	361	2,370	2	0
15	ENERGY	1,216	578	32	300	134	155	17	1,216	0	0
	PAYROLL TAXES										
16	PRODUCTION	3,419	1,698	83	682	291	353	15	3,122	96	201
	RETAIL JURISDICTION										
17	DEMAND		1,582	77	623	285	323	12	2,882		
18	ENERGY		116	6	59	26	30	3	240		
19	TRANSMISSION	299	158	8	62	26	32	1	287	9	3
20	DISTRIBUTION	1,600	1,083	72	245	72	28	98	1,598	1	0
21	DEMAND	854	507	27	209	71	28	11	853	1	0
22	CUSTOMER	745	576	45	36	1	0	87	745	0	0
23	CUSTOMER ACCOUNTS	958	834	63	38	1	1	13	950	8	0
24	CUSTOMER ASSISTANCE	1,010	659	134	170	25	23	0	1,011	0	0
25	CUSTOMER	1,010	659	134	170	25	23	0	1,011	0	0
26	ENERGY	0	0	0	0	0	0	0	0	0	0
27	SUBTOTAL ELEC. PAYROLL TAXES	7,286	4,432	360	1,197	415	437	127	6,968	114	204
28	DEMAND	4,332	2,247	112	894	362	383	24	4,022	106	204
29	CUSTOMER	2,714	2,069	242	244	27	24	100	2,706	8	0
30	ENERGY	240	116	6	59	26	30	3	240	0	0
31	ECCR PAYROLL ADJUSTMENT	(369)	(324)	(28)	(17)	0	0	0	(369)	0	0
32	NET ELEC. PAYROLL TAXES	6,917	4,108	332	1,180	415	437	127	6,599	114	204
33	DEMAND	4,332	2,247	112	894	362	383	24	4,022	106	204
34	CUSTOMER	2,714	2,069	242	244	27	24	100	2,706	8	0
35	ENERGY	(129)	(208)	(22)	42	26	30	3	(129)	0	0

GULF POWER COMPANY
12 MONTHS ENDING DECEMBER 31, 2014
12/13 DEMAND ALLOCATION - WITH MDS METHODOLOGY
SCHEDULE 4.30 - ANALYSIS OF TAXES OTHER THAN INCOME TAXES
($000'S)

LINE NO. (1)	DESCRIPTION (2)	TOTAL ELECTRIC SYSTEM (3)	RATE CLASS RESIDENTIAL (4)	RATE CLASS GS (5)	RATE CLASS GSD/GSDT (6)	RATE CLASS LP/LPT (7)	RATE CLASS MAJOR ACCTS (8)	RATE CLASS OS (9)	TOTAL RETAIL SERVICE (10)	WHOLESALE (11)	UNIT POWER SALES (12)
	REVENUE TAXES										
36	GROSS RECEIPTS TAX	0	0	0	0	0	0	0	0	0	0
37	FLA REG. COMM. ASSESSMENT	402	239	17	83	27	24	12	402	0	0
38	FUEL & ECCR REL. REV TAXES	0	0	0	0	0	0	0	0	0	0
39	FRANCHISE FEE REV. ADJ.	0	0	0	0	0	0	0	0	0	0
40	TOTAL REVENUE TAXES	402	239	17	83	27	24	12	402	0	0
	OTHER TAXES										
41	MISS. STATE FRAN. TAX	307	164	8	64	27	34	1	298	9	0
42	FRANCHISE FEE	41,160	24,514	1,696	8,487	2,802	2,431	1,230	41,160	0	0
43	MISCELLANEOUS TAXES	105	66	5	18	6	8	2	103	2	0
44	DEMAND	62	35	2	13	5	5	0	60	2	0
45	CUSTOMER	39	28	3	4	1	1	2	39	0	0
46	ENERGY	4	3	0	1	0	0	0	4	0	0
47	TOTAL OTHER TAXES	41,572	24,744	1,709	8,569	2,835	2,471	1,233	41,561	11	0
48	FRANCHISE FEE ADJUSTMENT	(41,160)	(24,514)	(1,696)	(8,487)	(2,802)	(2,431)	(1,230)	(41,160)	0	0
49	TOTAL TAXES OTHER THAN INC.	33,741	18,473	1,118	6,385	2,558	2,746	637	31,917	705	1,119
50	DEMAND	27,123	14,074	697	5,588	2,298	2,510	142	25,309	695	1,119
51	CUSTOMER	5,125	3,787	394	371	73	27	463	5,115	10	0
52	ENERGY	1,091	373	10	343	160	185	20	1,091	0	0
53	REVENUE RELATED	402	239	17	83	27	24	12	402	0	0

GULF POWER COMPANY
12 MONTHS ENDED DECEMBER 31, 2014
12/13 DEMAND ALLOCATION - WITH MDS METHODOLOGY
ANALYSIS OF TAXES OTHER THAN INCOME TAXES

Line No.	Ftnt Label	Description
1	(A)	Retail jurisdiction sum of Lines 2 and 3; Wholesale allocated per Level 1 Demand Allocator; UPS directly assigned.
2	(B)	Allocated per Level 1 Demand Allocator.
3	(C)	Allocated per Level 1 Energy Allocator.
4	(D)	Allocated per Transmission Gross Plant; UPS directly assigned.
5	(E)	Allocated per corresponding Distribution Gross Plant.
6	(E)	
7	(E)	
8	(F)	Allocated per corresponding Operations and Maintenance Expense.
9	(F)	
10	(F)	
11	(F)	
16	(G)	Allocated per corresponding Salaries and Wages; UPS directly assigned.
17	(H)	Allocated per corresponding Salaries and Wages.
18	(H)	
19	(G)	
20	(H)	
21	(H)	
22	(H)	
23	(H)	
24	(H)	
25	(H)	
26	(H)	
31	(I)	Provided by Gulf Power to Class. Allocated to rate per average number of customers within class.
36	(J)	Allocated per Retail Revenue from Sales.
37	(J)	
38	(K)	Allocated per Retail MWH Sales.
39	(J)	
41	(B)	
42	(J)	
43	(H)	
44	(H)	
45	(H)	
46	(H)	
48	(J)	

GULF POWER COMPANY
12 MONTHS ENDING DECEMBER 31, 2014
12/13 DEMAND ALLOCATION - WITH MDS METHODOLOGY
SCHEDULE 5.0 - LINE ALLOCATORS AND PERCENTAGES

LINE NO. (1)	DESCRIPTION (2)	TOTAL ELECTRIC SYSTEM (3)	RATE CLASS RESIDENTIAL (4)	RATE CLASS GS (5)	RATE CLASS GSD/GSDT (6)	RATE CLASS LP/LPT (7)	RATE CLASS MAJOR ACCTS (8)	RATE CLASS OS (9)	TOTAL RETAIL SERVICE (10)	WHOLESALE (11)	UNIT POWER SALES (12)
1	ENERGY - LEVEL 1	12,219,612	5,643,768	312,270	2,930,180	1,304,358	1,508,164	164,657	11,863,415	356,397	0
2	%	1.0000000	0.4616539	0.0255544	0.2397893	0.1067411	0.1234212	0.0134746	0.9706345	0.0291655	0.0000000
3	MWH SALES	11,505,326	5,264,445	291,283	2,733,687	1,233,654	1,477,619	153,590	11,154,278	351,048	0
4	%	1.0000000	0.4575659	0.0253172	0.2376019	0.1072245	0.1284291	0.0133495	0.9694882	0.0305118	0.0000000
	CP DEMAND										
5	LEVELS 1 & 2	2,149,333	1,144,164	55,758	451,028	191,920	233,603	8,774	2,085,247	64,086	0
6	%	1.0000000	0.5323344	0.0259420	0.2098456	0.0892929	0.1086863	0.0040822	0.9701833	0.0298167	0.0000000
7	LEVEL 3	1,892,426	1,123,290	54,741	442,800	163,656	99,125	8,614	1,892,426	0	0
8	%	1.0000000	0.5935714	0.0289264	0.2339854	0.0865851	0.0523799	0.0045518	1.0000000	0.0000000	0.0000000
	NCP DEMAND										
9	LEVEL 4	2,486,404	1,450,645	78,399	606,448	220,097	93,569	37,246	2,486,404	0	0
10	%	1.0000000	0.5834309	0.0315311	0.2439056	0.0885202	0.0376323	0.0149799	1.0000000	0.0000000	0.0000000
11	LEVEL 5	2,250,357	1,396,380	75,458	580,086	158,305	4,295	35,853	2,250,357	0	0
12	%	1.0000000	0.6205149	0.0335316	0.2577662	0.0703467	0.0019086	0.0159321	1.0000000	0.0000000	0.0000000
	AVERAGE NO. OF CUSTOMERS										
13	LEVEL 4 AND BELOW	443,319	386,033	29,156	17,494	276	48	10,312	443,319	0	0
14	%	1.0000000	0.8707793	0.0657675	0.0394614	0.0006227	0.0001083	0.0232609	1.0000000	0.0000000	0.0000000
15	LEVEL 5	443,246	386,033	29,154	17,486	248	33	10,312	443,246	0	0
16	%	1.0000000	0.8709227	0.0657739	0.0394048	0.0005596	0.0000745	0.0232647	1.0000000	0.0000000	0.0000000
17	TOTAL	443,351	386,033	29,156	17,497	284	68	10,312	443,350	1	0
18	%	1.0000000	0.8707164	0.0657628	0.0394653	0.0006407	0.0001534	0.0232592	0.9999977	0.0000023	0.0000000

GULF POWER COMPANY
12 MONTHS ENDING DECEMBER 31, 2014
12/13 DEMAND ALLOCATION - WITH MDS METHODOLOGY
SCHEDULE 5.0 - LINE ALLOCATORS AND PERCENTAGES

LINE NO. (1)	DESCRIPTION (2)	TOTAL ELECTRIC SYSTEM (3)	RATE CLASS RESIDENTIAL (4)	RATE CLASS GS (5)	RATE CLASS GSD/GSDT (6)	RATE CLASS LP/LPT (7)	RATE CLASS MAJOR ACCTS (8)	RATE CLASS OS (9)	TOTAL RETAIL SERVICE (10)	WHOLESALE (11)	UNIT POWER SALES (12)
	SALARIES AND WAGES										
19	PRODUCTION	37,806	19,921	979	6,020	3,426	4,152	181	36,879	1,127	0
	RETAIL JURISDICTION										
20	12/13 DEMAND RELATED		16,579	905	7,323	3,116	3,793	142	33,858		
21	1/13 ENERGY RELATED		1,342	74	697	310	359	39	2,821		
22	%	1.0000000	0.5269269	0.0258954	0.2121356	0.0906205	0.1098238	0.0047876	0.9701899	0.0298101	0.0000000
23	TRANSMISSION	3,307	1,765	85	695	296	356	13	3,210	97	0
24	%	1.0000000	0.5337164	0.0257031	0.2101603	0.0895071	0.1076504	0.0039311	0.9706683	0.0293317	0.0000000
	DISTRIBUTION										
25	DEMAND	9,443	5,591	298	2,311	789	315	126	9,430	13	0
26	CUSTOMER	8,261	6,384	498	401	13	6	956	8,256	3	0
27	TOTAL DISTRIBUTION	17,704	11,975	796	2,712	802	321	1,082	17,688	16	0
28	%	1.0000000	0.6764008	0.0449616	0.1531857	0.0453005	0.0181315	0.0611161	0.9990962	0.0009038	0.0000000
29	CUSTOMER ACCOUNTS	10,595	9,219	697	419	11	18	145	10,509	86	0
30	%	1.0000000	0.8701274	0.0657857	0.0395470	0.0010382	0.0016989	0.0136857	0.9918830	0.0081170	0.0000000
	CUSTOMER ASSISTANCE										
31	CUSTOMER	11,170	7,290	1,480	1,879	278	243	0	11,170	0	0
32	ENERGY	0	0	0	0	0	0	0	0	0	0
33	TOTAL CUSTOMER ASST.	11,170	7,290	1,480	1,879	278	243	0	11,170	0	0
34	%	1.0000000	0.6526410	0.1324978	0.1682184	0.0248881	0.0217647	0.0000000	1.0000000	0.0000000	0.0000000
	SUBTOTAL SALARIES & WAGES										
35	DEMAND	47,735	25,935	1,288	10,329	4,201	4,464	281	46,498	1,237	0
36	CUSTOMER	30,026	22,893	2,675	2,699	302	267	1,101	29,937	89	0
37	ENERGY	2,821	1,342	74	697	310	359	39	2,821	0	0
38	SUBTOTAL SALARIES & WAGES	80,582	50,170	4,037	13,725	4,813	5,090	1,421	79,256	1,326	0
39	%	1.0000000	0.6225956	0.0500980	0.1703234	0.0597280	0.0631655	0.0176342	0.9835447	0.0164553	0.0000000
40	ADMINISTRATIVE & GENERAL	16,913	10,530	847	2,881	1,010	1,069	296	16,635	278	0
41	%	1.0000000	0.6225980	0.0500798	0.1703423	0.0597174	0.0632058	0.0176196	0.9835629	0.0164371	0.0000000
42	TOTAL SALARIES & WAGES	97,495	60,700	4,884	16,606	5,823	6,159	1,719	95,891	1,604	0
43	%	1.0000000	0.6225960	0.0500949	0.1703257	0.0597261	0.0631725	0.0176317	0.9835479	0.0164521	0.0000000

GULF POWER COMPANY
12 MONTHS ENDED DECEMBER 31, 2014
12/13 DEMAND ALLOCATION - WITH MDS METHODOLOGY
ANALYSIS OF LINE ALLOCATORS AND PERCENTAGES

Line No.	Ftnt Label	Description
1	(A)	Energy at point of generation.
2	(B)	Percent of above lines total.
3	(C)	Total sales of energy at point of delivery.
4	(B)	
5	(D)	Coincident peak demand at Levels 1 & 2.
6	(B)	
7	(E)	Coincident peak demand at Level 3.
8	(B)	
9	(F)	Non-coincident peak demand at Level 4.
10	(B)	
11	(G)	Non-coincident peak demand at Level 5.
12	(B)	
13	(H)	Average number of customers at Levels 4 & 5.
14	(B)	
15	(I)	Average number of common customers at Level 5.
16	(B)	
17	(J)	Total average number of customers at all levels.
18	(B)	
19	(K)	Retail Jurisdiction sum of lines 2 & 3; Wholesale and Total Retail Service Allocated per Level 1 Demand Allocator.
20	(L)	Allocated per corresponding Level 1 Demand Allocator.
21	(M)	Allocated per corresponding Level 1 Energy Allocator.
22	(B)	
23	(N)	Allocated per Total Transmission O & M Expense excluding UPS.
24	(B)	
25	(O)	Allocated per demand related Distribution O & M Expense.
26	(P)	Allocated per customer related Distribution O & M Expense.
28	(B)	
29	(Q)	Allocated per Customer Accounts Expense excluding UPS.
30	(B)	
31	(R)	Allocated per customer related Customer Assistance Expense excluding UPS and Gulf Power Energy Services.
32	(S)	Allocated per energy related Customer Assistance Expense excluding UPS.
34	(B)	
40	(T)	Allocated per Subtotal Salaries and Wages.
41	(B)	

ATTACHMENT B:

COST OF SERVICE STUDY

12 MCP – 1/13TH KWH METHODOLOGY

GULF POWER COMPANY
12 MONTHS ENDING DECEMBER 31, 2014
12/13 DEMAND ALLOCATION
SCHEDULE 1.00 - PRESENT RATE SUMMARY
($000'S)

LINE NO. (1)	DESCRIPTION (2)	TOTAL ELECTRIC SYSTEM (3)	RATE CLASS RESIDENTIAL (4)	RATE CLASS GS (5)	RATE CLASS GSD/GSDT (6)	RATE CLASS LP/LPT (7)	RATE CLASS MAJOR ACCTS (8)	RATE CLASS OS (9)	TOTAL RETAIL SERVICE (10)	WHOLESALE (11)	UNIT POWER SALES (12)
	INVESTMENT										
1	ELECTRIC GROSS PLANT	3,391,076	1,669,784	93,465	620,705	240,800	231,823	87,591	2,944,168	55,729	391,179
2	ACCUMULATED DEPRECIATION	1,398,044	702,632	38,343	258,308	101,174	100,075	42,587	1,243,319	24,730	129,995
3	NET PLANT	1,993,032	966,952	55,122	362,397	139,626	131,748	45,004	1,700,849	30,999	261,184
4	MATERIALS AND SUPPLIES	154,358	70,674	3,601	33,713	14,555	15,952	2,316	141,011	3,814	9,533
5	OTHER WORKING CAPITAL	12,616	7,678	478	2,597	1,158	1,152	248	13,311	316	(1,011)
6	CONST. WORK IN PROGRESS	0	0	0	0	0	0	0	0	0	0
7	CWIP - NOT BEARING INTEREST	33,847	14,843	769	5,736	2,327	2,498	483	26,656	634	6,557
8	PLANT HELD FOR FUTURE USE	5,435	2,881	143	1,148	488	588	28	5,276	159	0
9	UNAMORT. PLANT ACQ. ADJUST.	1,903	0	0	0	0	0	0	0	0	1,903
10	INJURIES AND DAMAGES RESERVE	(3,354)	(1,987)	(158)	(585)	(206)	(208)	(58)	(3,202)	(54)	(98)
11	TOTAL ELECTRIC INVESTMENT	2,197,837	1,061,041	60,155	405,006	157,948	151,730	48,021	1,883,901	35,868	278,068
	REVENUES										
12	REVENUE FROM SALES	510,734	296,890	20,537	102,765	33,933	29,452	14,896	498,493	12,241	0
13	OTHER OPERATING REVENUES	69,171	37,068	2,295	11,598	9,553	3,380	1,384	65,278	3,893	0
14	REVENUE-NONASSOCIATED SALES	65,602	3,389	188	1,760	784	907	99	7,127	214	58,261
15	ADJUSTMENTS TO REVENUE	(42,247)	(25,162)	(1,740)	(8,711)	(2,876)	(2,496)	(1,262)	(42,247)	(0)	0
16	TOTAL ADJUSTED REVENUE	603,260	312,185	21,280	107,432	41,394	31,243	15,117	528,651	16,348	58,261
	EXPENSE										
17	OPERATIONS & MAINTENANCE	308,608	171,607	12,115	54,278	25,926	20,750	5,523	290,199	5,717	12,692
18	DEPRECIATION	114,402	59,337	3,485	21,813	8,287	7,885	3,698	104,505	1,922	7,975
19	AMORT. OF INV. TAX CREDIT	(1,224)	(499)	(29)	(183)	(70)	(66)	(31)	(878)	(16)	(330)
20	OTHER AMORTIZATION	0	0	0	0	0	0	0	0	0	0
21	REAL & PERSONAL PROP. TAX	26,010	13,641	725	5,238	2,158	2,265	488	24,515	580	915
22	PAYROLL TAX	8,917	4,018	321	1,248	442	446	124	6,599	114	204
23	REVENUE TAX	402	239	17	83	27	24	12	402	0	0
24	OTHER TAXES	41,572	24,742	1,709	8,570	2,836	2,471	1,233	41,581	11	0
25	ADJUSTMENT TO OTHER TAXES	(41,160)	(24,514)	(1,696)	(8,487)	(2,802)	(2,431)	(1,230)	(41,160)	0	0
26	EXPENSES EXCL. INC. TAX	455,527	248,571	16,647	82,560	36,804	31,344	9,817	425,743	8,328	21,456
27	OPERATING INCOME	147,733	63,614	4,633	24,872	4,590	(101)	5,300	102,908	8,020	36,805
28	STATE & FEDERAL INCOME TAX	34,676	13,295	1,150	5,303	97	(1,646)	1,536	19,735	2,714	12,227
29	INTEREST SYNCHRONIZATION	6,925	3,838	218	1,465	571	548	174	6,814	111	0
30	TOTAL INCOME TAXES	41,601	17,133	1,368	6,768	668	(1,098)	1,710	26,549	2,825	12,227
31	NET OPERATING INCOME	106,132	46,481	3,265	18,104	3,922	997	3,590	76,359	5,195	24,578
32	RATE OF RETURN	4.83%	4.38%	5.43%	4.47%	2.48%	0.66%	7.48%	4.05%		
33	RATE OF RETURN INDEX		108.08%	133.91%	110.28%	61.26%	16.21%	184.44%	100.00%		

GULF POWER COMPANY
12 MONTHS ENDED DECEMBER 31, 2014
12/13 DEMAND ALLOCATION
PRESENT RATE SUMMARY

Line No.	Ftnt Label	Description
1	(A)	From "Analysis of Gross Plant"
2	(B)	From "Analysis of Accumulated Depreciation Reserve"
4	(C)	From "Analysis of Materials and Supplies"
5	(D)	From "Analysis of Other Working Capital"
6	(E)	From "Analysis of Other Rate Base Items"
7	(E)	
8	(E)	
9	(E)	
10	(E)	
12	(F)	From "Analysis of Revenues"
13	(F)	
14	(F)	
15	(F)	
17	(G)	From "Analysis of Operations and Maintenance Expense"
18	(H)	From "Analysis of Depreciation Expense"
19	(I)	Allocated per Depreciation Expense; UPS directly assigned
20	(J)	Allocated per Total Production Gross Plant excluding UPS
21	(K)	From "Analysis of Taxes Other Than Income Taxes"
22	(K)	
23	(K)	
24	(K)	
25	(K)	
28	(L)	Income Taxes allocated per formula t = Rc - KI : where t = Total Income Taxes, R = Operating Income, c = Combined Effective Tax Rate of 0.38575, I = Total Electric Investment, and K = Income Tax Deduction factor of 0.0105957953; UPS directly assigned.
29	(M)	Retail portion allocated per Retail Rate Base; Total All Other and UPS directly assigned.
32	(N)	Rate of Return equals Net Operating Income Divided by Total Electric Investment.
33	(O)	Each Rate Class Rate of Return divided by Total Retail Service Rate of Return

GULF POWER COMPANY
12 MONTHS ENDING DECEMBER 31, 2014
12/13 DEMAND ALLOCATION
SCHEDULE 1.01 - EQUAL RATE OF RETURN SUMMARY - PRESENT RATES
($000'S)

LINE NO. (1)	DESCRIPTION (2)	TOTAL RETAIL SERVICE (3)	RATE CLASS RESIDENTIAL (4)	RATE CLASS GS (5)	RATE CLASS GSD/GSDT (6)	RATE CLASS LP/LPT (7)	RATE CLASS MAJOR ACCTS (8)	RATE CLASS OS (9)
1	EQUAL RATE OF RETURN	4.05%	4.05%	4.05%	4.05%	4.05%	4.05%	4.05%
2	PRESENT SYSTEM OPERATING INCOME	76,359	43,007	2,438	16,416	6,402	6,150	1,946
3	CURRENT OPERATING INCOME	76,359	46,481	3,265	18,104	3,922	997	3,590
4	CHANGE IN OPERATING INCOME	(0)	(3,474)	(827)	(1,688)	2,480	5,153	(1,644)
5	CHANGE IN INCOME TAXES	0	(2,182)	(519)	(1,060)	1,557	3,236	(1,032)
6	CURRENT INCOME TAXES	26,549	17,133	1,368	6,768	668	(1,098)	1,710
7	CHANGE IN EXPENSES	0	(22)	(5)	(10)	15	32	(10)
8	CURRENT EXPENSES	425,743	248,571	16,647	82,560	36,804	31,344	9,817
9	REV REQ - EQUAL SYSTEM ROR - PRESENT RATES	528,651	306,507	19,929	104,674	45,446	39,664	12,431
10	PRESENT REVENUE REQUIREMENTS	528,651	312,185	21,280	107,432	41,394	31,243	15,117
11	REVENUE EXCESS / DEFICIENCY	(0)	(5,678)	(1,351)	(2,758)	4,052	8,421	(2,686)
12	REV REQ INDEX - EQUAL SYSTEM ROR - PRES. RATES	100.00%	101.85%	106.78%	102.63%	91.08%	78.77%	121.61%

GULF POWER COMPANY
12 MONTHS ENDED DECEMBER 31, 2014
12/13 DEMAND ALLOCATION
EQUAL RATE OF RETURN SUMMARY - PRESENT RATES

Line No.	Ftnt Label	Description
1	(A)	From "Present Rate Summary", Total Retail Service Rate of Return
2	(B)	Line 1 times Total Rate Base - "Present Rate Summary"
3	(C)	From "Present Rate Summary"
4	(D)	Line 2 minus Line 3
5	(E)	Line 4 times the combined effective tax rate divided by 1 minus the combined effective tax rate
6	(C)	
7	(F)	Line 4 plus Line 5 times the Proposed Expense Factor divided by 1 minus the Proposed Expense Factor
8	(C)	
9	(G)	Line 2 plus Lines 5 - 8.
10	(C)	
11	(H)	Line 9 minus Line 10
12	(I)	Line 10 divided by Line 9

GULF POWER COMPANY
12 MONTHS ENDING DECEMBER 31, 2014
12/13 DEMAND ALLOCATION
SCHEDULE 1.10 - PROPOSED RATE SUMMARY
($000'S)

LINE NO. (1)	DESCRIPTION (2)	TOTAL ELECTRIC SYSTEM (3)	RATE CLASS RESIDENTIAL (4)	RATE CLASS GS (5)	RATE CLASS GSD/GSDT (6)	RATE CLASS LP/LPT (7)	RATE CLASS MAJOR ACCTS (8)	RATE CLASS OS (9)	TOTAL RETAIL SERVICE (10)	WHOLESALE (11)	UNIT POWER SALES (12)
1	TOTAL ELECTRIC INVESTMENT	2,197,837	1,061,041	60,155	405,006	157,948	151,730	48,021	1,883,901	35,868	278,068
	REVENUE										
2	PRESENT REVENUE	603,260	312,185	21,280	107,432	41,394	31,243	15,117	528,651	16,348	58,261
3	PROPOSED REVENUE	74,393	44,303	2,372	13,194	7,104	6,570	850	74,393	0	0
4	TOTAL REVENUE	677,653	356,488	23,652	120,626	48,498	37,813	15,967	603,044	16,348	58,261
	EXPENSE										
5	PRESENT OPERATING EXPENSES	455,527	248,571	16,647	82,560	36,804	31,344	9,817	425,743	8,328	21,456
6	PROPOSED EXPENSE INCREASE	272	162	9	48	26	24	3	272	0	0
7	TOTAL EXPENSES	455,799	248,733	16,656	82,608	36,830	31,368	9,820	426,015	8,328	21,456
8	OPERATING INCOME	221,854	107,755	6,996	38,018	11,668	6,445	6,147	177,029	8,020	36,805
	INCOME TAXES										
9	PRESENT INCOME TAXES	41,601	17,133	1,368	6,768	668	(1,098)	1,710	26,549	2,825	12,227
10	PROPOSED INC. TAX INCREASE	26,592	17,027	912	5,071	2,730	2,525	327	28,592	0	0
11	TOTAL INCOME TAXES	70,193	34,160	2,280	11,839	3,398	1,427	2,037	55,141	2,825	12,227
12	NET OPERATING INCOME	151,661	73,595	4,716	26,179	8,270	5,018	4,110	121,888	5,195	24,578
13	RATE OF RETURN	6.90%	6.94%	7.84%	6.46%	5.24%	3.31%	8.56%	6.47%		
14	RATE OF RETURN INDEX		107.20%	121.17%	99.91%	80.93%	51.12%	132.28%	100.00%		

GULF POWER COMPANY
12 MONTHS ENDED DECEMBER 31, 2014
12/13 DEMAND ALLOCATION
PROPOSED RATE SUMMARY

Line No.	Ftnt Label	Description
1	(A)	From "Present Rate Summary"
2	(A)	
3	(B)	Provided by Pricing, Costing & Load Research, Gulf Power Company.
5	(A)	
6	(C)	Calculated by multiplying Proposed Revenues times the appropriate Proposed Expense Factor
8	(D)	Operating Income equals Total Revenue minus Total Expenses.
9	(A)	
10	(E)	Proposed Income Tax Increase calculated by multiplying Proposed Revenue minus Proposed Expense Increase times Effective Tax Rate of 0.38575.
12	(F)	Net Operating Income equals Operating Income less Total Income Taxes.
13	(G)	Rate of Return equals Net Operating Income Divided by Total Electric Investment.
14	(H)	Each Rate Class Rate of Return divided by Total Retail Service Rate of Return

GULF POWER COMPANY
12 MONTHS ENDING DECEMBER 31, 2014
12/13 DEMAND ALLOCATION
SCHEDULE 1.11 - EQUAL RATE OF RETURN SUMMARY - PROPOSED RATES
($000'S)

LINE NO. (1)	DESCRIPTION (2)	TOTAL RETAIL SERVICE (3)	RATE CLASS RESIDENTIAL (4)	RATE CLASS GS (5)	RATE CLASS GSD/GSDT (6)	RATE CLASS LP/LPT (7)	RATE CLASS MAJOR ACCTS (8)	RATE CLASS OS (9)
1	EQUAL RATE OF RETURN	6.47%	6.47%	6.47%	6.47%	6.47%	6.47%	6.47%
2	PROPOSED OPERATING INCOME	121,888	68,650	3,892	26,204	10,219	9,817	3,107
3	CURRENT OPERATING INCOME	76,359	46,481	3,265	18,104	3,922	997	3,590
4	CHANGE IN OPERATING INCOME	45,530	22,169	627	8,100	6,297	8,820	(483)
5	CHANGE IN INCOME TAXES	28,594	13,922	394	5,087	3,955	5,539	(303)
6	PRESENT INCOME TAXES	26,549	17,133	1,368	6,768	668	(1,098)	1,710
7	CHANGE IN EXPENSES	273	132	4	48	38	53	(3)
8	PRESENT EXPENSES	425,743	248,571	16,647	82,560	36,804	31,344	9,817
9	REV REQ - EQUAL SYSTEM ROR - PROPOSED RATES	603,047	348,408	22,305	120,666	51,684	45,655	14,328
10	PRESENT REVENUE REQUIREMENTS	528,651	312,185	21,280	107,432	41,394	31,243	15,117
11	REVENUE EXCESS / DEFICIENCY	74,395	36,223	1,025	13,234	10,290	14,412	(789)
12	REV REQ INDEX - EQUAL SYSTEM ROR - PROP. RATES	87.68%	89.60%	95.40%	89.03%	80.09%	68.43%	105.51%

GULF POWER COMPANY
12 MONTHS ENDED DECEMBER 31, 2014
12/13 DEMAND ALLOCATION
EQUAL RATE OF RETURN SUMMARY - PROPOSED RATES

Line No.	Ftnt Label	Description
1	(A)	From "Proposed Rate Summary", Total Retail Service Rate of Return
2	(B)	Line 1 times Total Rate Base - "Proposed Rate Summary"
3	(C)	From "Present Rate Summary"
4	(D)	Line 2 minus Line 3
5	(E)	Line 4 times the combined effective tax rate divided by 1 minus the combined effective tax rate
6	(C)	
7	(F)	Line 4 plus Line 5 times the Proposed Expense Factor divided by 1 minus the Proposed Expense Factor
8	(C)	
9	(G)	Line 2 plus Lines 5 - 8.
10	(C)	
11	(H)	Line 9 minus Line 10
12	(I)	Line 10 divided by Line 9

GULF POWER COMPANY
12 MONTHS ENDING DECEMBER 31, 2014
12/13 DEMAND ALLOCATION
SCHEDULE 2.10 - ANALYSIS OF GROSS PLANT
($000'S)

LINE NO. (1)	DESCRIPTION (2)	TOTAL ELECTRIC SYSTEM (3)	RATE CLASS RESIDENTIAL (4)	RATE CLASS GS (5)	RATE CLASS GSD/GSDT (6)	RATE CLASS LP/LPT (7)	RATE CLASS MAJOR ACCTS (8)	RATE CLASS OS (9)	TOTAL RETAIL SERVICE (10)	WHOLESALE (11)	UNIT POWER SALES (12)
1	TOTAL PRODUCTION PLANT	1,571,047	627,458	30,856	252,627	107,929	130,774	5,721	1,155,365	35,508	380,174
	RETAIL JURISDICTION										
2	DEMAND		585,178	28,517	230,676	98,157	119,476	4,487	1,066,491		
3	ENERGY		42,280	2,339	21,951	9,772	11,298	1,234	88,874		
	TRANSMISSION PLANT										
	350-LAND & LAND RIGHTS										
1	SUBSTATIONS										
4	LEVEL 2 COMMON	1,541	821	40	323	138	167	6	1,495	46	0
5	LEVEL 3 COMMON	591	351	17	138	51	31	3	591	0	0
6	TOTAL SUBSTATION LAND	2,132	1,172	57	461	189	198	9	2,086	46	0
	LINES										
7	LEVEL 2 COMMON	18,183	9,678	472	3,816	1,624	1,977	74	17,641	542	0
8	TOTAL ACCOUNT 350	20,315	10,850	529	4,277	1,813	2,175	83	19,727	588	0
	352-STRUCTURES										
9	LEVEL 2 CUSTOMER SUB	2	0	0	0	0	2	0	2	0	0
10	LEVEL 2 COMMON	9,550	5,083	248	2,004	853	1,038	39	9,265	285	0
11	LEVEL 3 COMMON	1,439	853	42	337	125	75	7	1,439	0	0
12	TOTAL ACCOUNT 352	10,991	5,936	290	2,341	978	1,115	46	10,706	285	0
	353-STATION EQUIPMENT										
13	LEVEL 2 CUSTOMER SUB	140	0	0	0	0	140	0	140	0	0
14	LEVEL 2 COMMON	125,696	63,534	3,096	25,045	10,657	12,971	487	115,790	3,559	6,347
15	LEVEL 3 COMMON	38,170	22,657	1,104	8,931	3,305	1,999	174	38,170	0	0
16	TOTAL ACCOUNT 353	164,006	86,191	4,200	33,978	13,962	15,110	661	154,100	3,559	6,347
	354-TOWERS AND FIXTURES										
17	LEVEL 2 COMMON	42,804	22,787	1,110	8,982	3,822	4,652	175	41,528	1,276	0
	355-POLES AND FIXTURES										
18	LEVEL 2 COMMON	148,976	79,305	3,865	31,262	13,302	16,192	608	144,534	4,442	0
	356-OVERHEAD CONDUCTORS										
19	LEVEL 2 COMMON	85,526	45,529	2,219	17,947	7,637	9,295	349	82,976	2,550	0
	358-UNDERGROUND CONDUCTORS										
20	LEVEL 2 COMMON	14,095	7,502	366	2,958	1,259	1,532	58	13,675	420	0
	359-ROADS AND TRAILS										
21	LEVEL 2 COMMON	236	126	6	50	21	25	1	229	7	0
22	TOTAL TRANS. PLANT	486,949	258,226	12,585	101,793	42,794	50,096	1,981	467,475	13,127	6,347

GULF POWER COMPANY
12 MONTHS ENDING DECEMBER 31, 2014
12/13 DEMAND ALLOCATION
SCHEDULE 2.10 - ANALYSIS OF GROSS PLANT
($000'S)

LINE NO. (1)	DESCRIPTION (2)	TOTAL ELECTRIC SYSTEM (3)	RATE CLASS RESIDENTIAL (4)	RATE CLASS GS (5)	RATE CLASS GSD/GSDT (6)	RATE CLASS LP/LPT (7)	RATE CLASS MAJOR ACCTS (8)	RATE CLASS OS (9)	TOTAL RETAIL SERVICE (10)	WHOLESALE (11)	UNIT POWER SALES (12)
	DISTRIBUTION PLANT										
	360-SUBSTATION LAND										
23	LEVEL 3 CUST. SUB	74	0	0	0	0	11	0	11	62	0
24	LEVEL 3 COMMON	4,584	2,720	133	1,073	397	240	21	4,584	0	0
25	LEVEL 4 COMMON	12	8	0	3	1	0	0	12	0	0
26	TOTAL ACCOUNT 360	4,670	2,728	133	1,076	398	251	21	4,607	62	0
	361-STRUCTURES										
27	LEVEL 3 CUST. SUB	2,007	0	0	0	617	963	0	1,581	426	0
28	LEVEL 3 COMMON	21,220	12,596	614	4,965	1,837	1,111	97	21,220	0	0
29	LEVEL 4 COMMON	0	0	0	0	0	0	0	0	0	0
30	TOTAL ACCOUNT 361	23,227	12,596	614	4,965	2,454	2,074	97	22,801	426	0
	362-STATION EQUIPMENT										
31	LEVEL 3 CUST. SUB	20,433	0	0	0	4,195	12,566	0	16,761	3,672	0
32	LEVEL 3 COMMON	205,570	122,021	5,946	48,100	17,799	10,768	936	205,570	0	0
33	LEVEL 4 COMMON	23	13	1	6	2	1	0	23	0	0
34	TOTAL ACCOUNT 362	226,026	122,034	5,947	48,106	21,996	23,335	936	222,354	3,672	0
	364-POLES AND FIXTURES										
35	LEVEL 4 COMMON	103,954	60,650	3,278	25,355	9,202	3,912	1,557	103,954	0	0
36	LEVEL 4 CUSTOMER	0	(0)	0	0	0	0	0	0	0	0
37	LEVEL 5 COMMON	29,635	18,514	1,000	7,690	2,099	57	475	29,835	0	0
38	LEVEL 5 CUSTOMER	(0)	(0)	0	0	0	0	0	(0)	0	0
39	TOTAL ACCOUNT 364	133,789	79,164	4,278	33,045	11,301	3,969	2,032	133,789	0	0
	365-OVERHEAD CONDUCTORS										
40	LEVEL 4 COMMON	107,612	62,784	3,393	26,247	9,526	4,050	1,612	107,612	0	0
41	LEVEL 4 CUSTOMER	0	(0)	0	0	0	0	0	0	0	0
42	LEVEL 5 COMMON	29,999	18,615	1,006	7,733	2,110	57	478	29,999	0	0
43	LEVEL 5 CUSTOMER	(0)	(0)	0	0	0	0	0	(0)	0	0
44	TOTAL ACCOUNT 365	137,611	81,399	4,399	33,980	11,636	4,107	2,090	137,611	0	0
	366-UNDERGROUND CONDUIT										
45	LEVEL 4 COMMON	697	407	22	170	62	26	10	697	0	0
46	LEVEL 4 CUSTOMER	0	(0)	0	0	0	0	0	0	0	0
47	LEVEL 5 COMMON	464	287	16	120	33	1	7	464	0	0
48	LEVEL 5 CUSTOMER	(0)	(0)	0	0	0	0	0	(0)	0	0
49	TOTAL ACCOUNT 366	1,161	694	38	290	95	27	17	1,161	0	0
	367-UNDERGROUND COND. & DEV.										
50	LEVEL 4 COMMON	104,241	60,817	3,287	25,425	9,227	3,923	1,562	104,241	0	0
51	LEVEL 4 CUSTOMER	0	(0)	0	0	0	0	0	0	0	0
52	LEVEL 5 COMMON	42,577	26,420	1,428	10,975	2,995	81	678	42,577	0	0
53	LEVEL 5 CUSTOMER	(0)	(0)	0	0	0	0	0	(0)	0	0
54	TOTAL ACCOUNT 367	146,818	87,237	4,715	36,400	12,222	4,004	2,240	146,818	0	0

GULF POWER COMPANY
12 MONTHS ENDING DECEMBER 31, 2014
12/13 DEMAND ALLOCATION
SCHEDULE 2.10 - ANALYSIS OF GROSS PLANT
($000'S)

LINE NO. (1)	DESCRIPTION (2)	TOTAL ELECTRIC SYSTEM (3)	RATE CLASS RESIDENTIAL (4)	RATE CLASS GS (5)	RATE CLASS GSD/GSDT (6)	RATE CLASS LP/LPT (7)	RATE CLASS MAJOR ACCTS (8)	RATE CLASS OS (9)	TOTAL RETAIL SERVICE (10)	WHOLESALE (11)	UNIT POWER SALES (12)
	368-LINE TRANSFORMERS										
55	LEVEL 4 COMMON	39,585	23,095	1,248	9,655	3,504	1,490	593	39,585	0	0
56	LEVEL 4 CUSTOMER	0	(0)	0	0	0	0	0	0	0	0
57	LEVEL 5 COMMON	214,165	132,892	7,181	55,205	15,066	409	3,412	214,165	0	0
58	LEVEL 5 CUSTOMER	(0)	(0)	0	0	0	0	0	(0)	0	0
59	TOTAL ACCOUNT 368	253,750	155,987	8,429	64,860	18,570	1,899	4,005	253,750	0	0
	369-SERVICES										
60	HOUSE POWER BOXES	0	0	0	0	0	0	0	0	0	0
61	OTHER SERVICES	99,675	88,677	6,712	4,021	57	8	0	99,675	0	0
62	TOTAL ACCOUNT 369	99,675	88,677	6,712	4,021	57	8	0	99,675	0	0
63	370-METERS	65,096	48,878	6,437	8,768	494	266	138	64,981	115	0
64	373-STREET LIGHTING	65,351	0	0	0	0	0	65,351	65,351	0	0
65	TOTAL DIST. PLANT	1,157,174	679,594	41,702	235,511	79,224	39,941	76,927	1,152,898	4,276	0
66	DEMAND	927,052	541,839	28,553	222,722	78,673	39,667	11,438	922,891	4,161	0
67	CUSTOMER	230,122	137,755	13,149	12,789	551	274	65,489	230,007	115	0
	GENERAL PLANT										
68	ELECTRIC	175,906	104,506	8,322	30,774	10,853	11,013	2,962	168,430	2,818	4,658
69	DEMAND	113,755	59,678	2,982	23,855	9,555	9,682	716	106,468	2,629	4,658
70	CUSTOMER	58,155	41,975	5,183	5,438	640	567	2,163	55,966	189	0
71	ENERGY	5,996	2,853	157	1,481	658	764	83	5,996	0	0
72	TOTAL GENERAL PLANT	175,906	104,506	8,322	30,774	10,853	11,013	2,962	168,430	2,818	4,658
73	TOTAL ELEC. GROSS PLANT	3,391,076	1,669,784	93,465	620,705	240,800	231,823	87,591	2,944,168	55,729	391,179
74	DEMAND	3,009,928	1,444,921	72,637	579,046	229,179	218,920	18,622	2,563,325	55,425	391,179
75	CUSTOMER	286,277	179,730	18,332	18,227	1,191	641	67,652	285,973	304	0
76	ENERGY	94,870	45,133	2,496	23,432	10,430	12,062	1,317	94,870	0	0

GULF POWER COMPANY
12 MONTHS ENDED DECEMBER 31, 2014
12/13 DEMAND ALLOCATION
ANALYSIS OF GROSS PLANT

Line No.	Ftnt Label	Description
1	(A)	Retail jurisdiction sum of Lines 2 and 3; Wholesale allocated per Level 1 Demand Allocator; UPS directly assigned.
2	(B)	Allocated per corresponding Level 1 Demand Allocator.
3	(C)	Allocated per corresponding Level 1 Energy Allocator.
4	(D)	Allocated per Level 2 Demand Allocator; UPS directly assigned.
5	(E)	Allocated per Level 3 Demand Allocator.
7	(D)	
9	(F)	Specific Assignment
10	(D)	
11	(E)	
13	(F)	
14	(D)	
15	(E)	
17	(D)	
18	(D)	
19	(D)	
20	(D)	
21	(D)	
23	(F)	
24	(E)	
25	(G)	Allocated per Level 4 NCP Demand Allocator
27	(F)	
28	(E)	
29	(G)	
31	(F)	
32	(E)	
33	(G)	
35	(G)	
36	(H)	Allocated per Average Number of Customers at Level 4 and Level 5.
37	(I)	Allocated per Level 5 NCP Demand Allocator
38	(J)	Allocated per Average Number of Customers at Level 5.

GULF POWER COMPANY
12 MONTHS ENDED DECEMBER 31, 2014
12/13 DEMAND ALLOCATION
ANALYSIS OF GROSS PLANT

Line No.	Ftnt Label	Description
40	(G)	
41	(H)	
42	(I)	
43	(J)	
45	(G)	
46	(H)	
47	(I)	
48	(J)	
50	(G)	
51	(H)	
52	(I)	
53	(J)	
55	(G)	
56	(H)	
57	(I)	
58	(J)	
60	(F)	
61	(K)	Allocated per Average Number of Customers at Level 5 excluding Rate OS.
63	(L)	Provided by Gulf Power Company
64	(F)	
68	(M)	Allocated per corresponding Salaries and Wages; UPS directly assigned.
69	(M)	
70	(M)	
71	(M)	

GULF POWER COMPANY
12 MONTHS ENDING DECEMBER 31, 2014
12/13 DEMAND ALLOCATION
SCHEDULE 2.20 - ANALYSIS OF ACCUMULATED DEPRECIATION RESERVE
($000'S)

LINE NO. (1)	DESCRIPTION (2)	TOTAL ELECTRIC SYSTEM (3)	RATE CLASS RESIDENTIAL (4)	RATE CLASS GS (5)	RATE CLASS GSD/GSDT (6)	RATE CLASS LP/LPT (7)	RATE CLASS MAJOR ACCTS (8)	RATE CLASS OS (9)	TOTAL RETAIL SERVICE (10)	WHOLESALE (11)	UNIT POWER SALES (12)
1	TOTAL PRODUCTION	759,866	334,127	16,432	134,526	57,474	69,638	3,046	615,243	18,908	125,715
	RETAIL JURISDICTION										
2	DEMAND		311,613	15,166	122,837	52,270	63,622	2,389	567,917		
3	ENERGY		22,514	1,246	11,689	5,204	6,016	657	47,326		
	TRANSMISSION										
4	350-LAND AND LAND RIGHTS	6,616	3,629	177	1,430	609	740	28	6,613	203	0
5	352-STRUCTURES	3,645	1,969	96	776	324	370	15	3,550	95	0
6	353-STATION EQUIPMENT	32,146	16,252	792	6,406	2,633	2,849	125	29,057	671	2,416
7	354-TOWERS & FIXTURES	25,433	13,539	660	5,337	2,271	2,764	104	24,675	758	0
8	355-POLES & FIXTURES	26,313	14,007	683	5,522	2,349	2,860	107	25,528	785	0
9	356-OVERHEAD COND.	26,168	13,930	679	5,491	2,337	2,844	107	25,388	780	0
10	358-UNDERGROUND COND.	7,657	4,075	199	1,607	684	832	32	7,429	228	0
11	359-ROADS AND TRAILS	40	22	1	6	4	4	0	39	1	0
12	TOTAL TRANSMISSION	128,216	67,423	3,287	26,577	11,211	13,263	516	122,279	3,521	2,416
	DISTRIBUTION										
13	360-SUBSTATION LAND	35	21	1	6	3	2	0	35	0	0
14	361-STRUCTURES	7,861	4,262	208	1,680	831	703	33	7,717	144	0
15	362-STATION EQUIPMENT	61,193	33,040	1,610	13,024	5,955	6,317	253	60,199	994	0
	364-POLES & FIXTURES										
16	COMMON	68,632	40,728	2,201	17,002	5,614	2,042	1,045	68,832	0	0
17	CUSTOMER	0	0	0	0	0	0	0	0	0	0
18	TOTAL ACCOUNT 364	68,632	40,728	2,201	17,002	5,614	2,042	1,045	68,832	0	0
	365-OVERHEAD COND.										
19	COMMON	48,656	28,781	1,555	12,015	4,114	1,452	739	48,656	0	0
20	CUSTOMER	0	0	0	0	0	0	0	0	0	0
21	TOTAL ACCOUNT 365	48,656	28,781	1,555	12,015	4,114	1,452	739	48,656	0	0

GULF POWER COMPANY
12 MONTHS ENDING DECEMBER 31, 2014
12/13 DEMAND ALLOCATION
SCHEDULE 2.20 - ANALYSIS OF ACCUMULATED DEPRECIATION RESERVE
($000'S)

LINE NO. (1)	DESCRIPTION (2)	TOTAL ELECTRIC SYSTEM (3)	RATE CLASS RESIDENTIAL (4)	RATE CLASS GS (5)	RATE CLASS GSD/GSDT (6)	RATE CLASS LP/LPT (7)	RATE CLASS MAJOR ACCTS (8)	RATE CLASS OS (9)	TOTAL RETAIL SERVICE (10)	WHOLESALE (11)	UNIT POWER SALES (12)
	366-UNDG. CONDUIT										
22	COMMON	800	477	26	201	65	19	12	800	0	0
23	CUSTOMER	0	0	0	0	0	0	0	0	0	0
24	TOTAL ACCOUNT 366	800	477	26	201	65	19	12	800	0	0
	367-UNDERGROUND COND. & DEV.										
25	COMMON	52,723	31,327	1,693	13,072	4,389	1,438	804	52,723	0	0
26	CUSTOMER	0	0	0	0	0	0	0	0	0	0
27	TOTAL ACCOUNT 367	52,723	31,327	1,693	13,072	4,389	1,438	804	52,723	0	0
	368-LINE TRANSFORMERS										
28	COMMON	92,899	57,107	3,086	23,746	6,799	695	1,466	92,899	0	0
29	CUSTOMER	0	0	0	0	0	0	0	0	0	0
30	TOTAL ACCOUNT 368	92,899	57,107	3,086	23,746	6,799	695	1,466	92,899	0	0
31	369-SERVICES	50,834	45,327	3,423	2,051	29	4	0	50,834	0	0
32	370-METERS	21,743	18,057	1,464	1,993	112	60	31	21,717	26	0
33	373-STREET LIGHTING	33,445	0	0	0	0	0	33,445	33,445	0	0
34	TOTAL DISTRIBUTION	439,021	259,127	15,267	64,792	28,111	12,732	37,828	437,857	1,164	0
35	DEMAND	332,999	195,743	10,380	60,748	27,970	12,668	4,352	331,861	1,138	0
36	CUSTOMER	106,022	63,384	4,887	4,044	141	64	33,476	105,996	26	0
	GENERAL PLANT										
	ELECTRIC										
37	DEMAND	45,869	24,073	1,203	9,622	3,854	3,906	289	42,947	1,060	1,862
38	CUSTOMER	22,651	16,930	2,091	2,194	258	229	873	22,575	76	0
39	ENERGY	2,419	1,152	63	597	266	307	33	2,418	1	0
40	TOTAL ELECTRIC GENERAL PLANT	70,939	42,155	3,357	12,413	4,378	4,442	1,195	67,940	1,137	1,862
41	TOTAL ELECTRIC DEPR. RESERVE	1,398,044	702,832	38,343	258,308	101,174	100,075	42,587	1,243,319	24,730	129,995
42	DEMAND	1,219,626	598,852	30,056	239,784	95,305	93,459	7,548	1,065,004	24,627	129,995
43	CUSTOMER	128,673	80,314	6,978	6,238	399	293	34,349	128,571	102	0
44	ENERGY	49,745	23,668	1,309	12,286	5,470	6,323	690	49,744	1	0

GULF POWER COMPANY
12 MONTHS ENDED DECEMBER 31, 2014
12/13 DEMAND ALLOCATION
ANALYSIS OF ACCUMULATED DEPRECIATION RESERVE

Line No.	Ftnt Label	Description
1	(A)	Retail jurisdiction sum of Lines 2 and 3; Wholesale allocated per Level 1 Demand Allocator; UPS directly assigned.
2	(B)	Allocated per corresponding Level 1 Demand Allocator.
3	(C)	Allocated per corresponding Level 1 Energy Allocator.
4	(D)	Allocated per Transmission Account 350 Gross Plant (Lines portion only); UPS directly assigned.
5	(E)	Allocated per corresponding Transmission Gross Plant; UPS directly assigned.
6	(E)	
7	(E)	
8	(E)	
9	(E)	
10	(E)	
11	(E)	
13	(F)	Allocated per corresponding Distribution Gross Plant.
14	(F)	
15	(F)	
16	(F)	
17	(F)	
19	(F)	
20	(F)	
22	(F)	
23	(F)	
25	(F)	
26	(F)	
28	(F)	
29	(F)	
31	(F)	
32	(F)	
33	(F)	
37	(G)	Allocated per corresponding Gross General Plant; UPS directly assigned.
38	(G)	
39	(G)	

GULF POWER COMPANY
12 MONTHS ENDING DECEMBER 31, 2014
12/13 DEMAND ALLOCATION
SCHEDULE 2.30 - ANALYSIS OF MATERIALS AND SUPPLIES
($000'S)

LINE NO. (1)	DESCRIPTION (2)	TOTAL ELECTRIC SYSTEM (3)	RATE CLASS RESIDENTIAL (4)	RATE CLASS GS (5)	RATE CLASS GSD/GSDT (6)	RATE CLASS LP/LPT (7)	RATE CLASS MAJOR ACCTS (8)	RATE CLASS OS (9)	TOTAL RETAIL SERVICE (10)	WHOLESALE (11)	UNIT POWER SALES (12)
	PRODUCTION										
1	NON-FUEL	30,413	14,766	726	5,943	2,539	3,074	135	27,183	900	2,330
	RETAIL JURISDICTION										
2	DEMAND		13,768	671	5,427	2,309	2,811	106	25,092		
3	ENERGY		998	55	516	230	263	29	2,091		
4	FUEL	103,229	44,350	2,454	23,026	10,250	11,851	1,294	93,225	2,801	7,203
5	TOTAL PRODUCTION M & S	133,642	59,116	3,180	28,969	12,789	14,925	1,429	120,408	3,701	9,533
	TRANSMISSION										
6	LINES RELATED	2,495	1,328	65	524	223	271	10	2,421	74	0
7	SUBSTATION RELATED	1,687	922	45	363	149	163	7	1,649	38	0
8	TOTAL TRANS. M & S	4,182	2,250	110	887	372	434	17	4,070	112	0
	DISTRIBUTION										
9	DEMAND RELATED	15,483	9,033	488	3,776	1,371	583	232	15,483	0	0
10	METERING RELATED	166	127	16	22	1	0	0	166	0	0
11	ST. LIGHTING RELATED	635	0	0	0	0	0	635	635	0	0
12	OTHER	240	141	7	58	20	10	3	239	1	0
13	TOTAL DIST. M & S	16,525	9,302	511	3,856	1,392	593	870	16,524	1	0
14	CUSTOMER ACCOUNTS	5	5	0	0	0	0	0	5	0	0
15	CUSTOMER ASSISTANCE	5	2	0	1	2	0	0	5	0	0
16	TOTAL ELECTRIC M & S	154,358	70,674	3,801	33,713	14,555	15,952	2,316	141,011	3,814	9,533
17	DEMAND	48,228	25,193	1,276	10,148	4,072	3,838	358	44,885	1,013	2,330
18	CUSTOMER	811	134	16	23	3	0	635	811	0	0
19	ENERGY	105,320	45,348	2,509	23,542	10,480	12,114	1,323	95,316	2,801	7,203

GULF POWER COMPANY
12 MONTHS ENDED DECEMBER 31, 2014
12/13 DEMAND ALLOCATION
ANALYSIS OF MATERIALS AND SUPPLIES

Line No.	Ftnt Label	Description
1	(A)	Retail jurisdiction sum of Lines 2 and 3; Wholesale allocated per Level 1 Demand Allocator; UPS directly assigned.
2	(B)	Allocated per corresponding Level 1 Demand Allocator.
3	(C)	Allocated per corresponding Level 1 Energy Allocator.
4	(D)	Allocated per Level 1 Energy Allocator; UPS directly assigned.
6	(E)	Allocated per Level 2 Demand Allocator; UPS directly assigned.
7	(F)	Allocated per Gross Investment in Transmission Substations excluding UPS.
9	(G)	Allocated per Level 4 NCP Demand Allocator.
10	(H)	Allocated per Distribution Gross Plant in Account 370.
11	(I)	Directly assigned to Street Lighting.
12	(J)	Allocated per Demand-related Distribution Gross Plant.
14	(K)	Allocated per Customer Accounts O & M Expense.
15	(L)	Allocated per Customer Assistance O & M Energy Cost Conservation.

GULF POWER COMPANY
12 MONTHS ENDING DECEMBER 31, 2014
12/13 DEMAND ALLOCATION
SCHEDULE 2.40 - ANALYSIS OF OTHER WORKING CAPITAL
($000'S)

LINE NO. (1)	DESCRIPTION (2)	TOTAL ELECTRIC SYSTEM (3)	RATE CLASS RESIDENTIAL (4)	RATE CLASS GS (5)	RATE CLASS GSD/GSDT (6)	RATE CLASS LP/LPT (7)	RATE CLASS MAJOR ACCTS (8)	RATE CLASS OS (9)	TOTAL RETAIL SERVICE (10)	WHOLESALE (11)	UNIT POWER SALES (12)
	OTHER WORKING CAPITAL										
1	CURRENT ASSETS & LIAB.	(7,220)	(4,184)	(296)	(1,255)	(593)	(453)	(137)	(6,918)	(128)	(174)
2	DEMAND	(4,971)	(2,632)	(132)	(1,053)	(420)	(420)	(32)	(4,689)	(108)	(174)
3	CUSTOMER	(1,956)	(1,373)	(153)	(153)	(155)	(14)	(101)	(1,949)	(7)	0
4	ENERGY	(113)	(51)	(2)	(30)	(13)	(15)	(2)	(113)	0	0
5	REVENUE RELATED	(180)	(128)	(9)	(19)	(5)	(4)	(2)	(167)	(13)	0
6	CABLE ATTACHMENTS	(2,327)	(1,351)	(95)	(403)	(191)	(145)	(45)	(2,230)	(41)	(56)
7	DEMAND	(1,602)	(850)	(42)	(339)	(135)	(135)	(10)	(1,511)	(35)	(56)
8	CUSTOMER	(630)	(443)	(49)	(49)	(50)	(4)	(33)	(628)	(2)	0
9	ENERGY	(35)	(15)	(1)	(9)	(4)	(5)	(1)	(35)	0	0
10	REVENUE RELATED	(58)	(43)	(3)	(6)	(2)	(1)	(1)	(56)	(4)	0
	PREPAYMENTS										
11	PRODUCTION	7,233	3,682	181	1,483	633	768	33	6,780	208	245
	RETAIL JURISDICTION										
12	DEMAND		3,434	167	1,354	576	701	26	6,258		
13	ENERGY		248	14	129	57	67	7	522		
14	TRANSMISSION	2,680	1,439	70	568	239	280	11	2,607	73	0
15	DISTRIBUTION	6,567	3,858	237	1,334	448	226	440	6,543	24	0
16	DEMAND	5,248	3,057	162	1,261	445	225	65	5,225	23	0
17	CUSTOMER	1,319	791	75	73	3	1	375	1,318	1	0
18	CUSTOMER ACCOUNTS	124	108	8	5	0	0	2	123	1	0
19	CUSTOMER ASSSISTANCE	130	58	12	15	43	2	0	130	0	0
20	CUSTOMER	130	58	12	15	43	2	0	130	0	0
21	ENERGY	0	0	0	0	0	0	0	0	0	0
22	TOTAL PREPAYMENTS	16,734	9,145	508	3,405	1,363	1,276	486	16,183	306	245
23	DEMAND	14,639	7,940	399	3,183	1,260	1,208	102	14,090	304	245
24	CUSTOMER	1,573	957	95	93	46	3	377	1,571	2	0
25	ENERGY	522	248	14	129	57	67	7	522	0	0
26	PRELIM. SURVEY & INVESTIGATION	5,238	2,760	135	1,112	475	575	25	5,082	156	0
	RETAIL JURISDICTION										
27	DEMAND		2,574	125	1,015	432	525	20	4,691		
28	ENERGY		186	10	97	43	50	5	391		
	OTHER INVESTMENTS										
29	PRODUCTION	34,471	16,162	892	7,313	3,124	3,787	165	33,443	1,028	0
	RETAIL JURISDICTION										
30	DEMAND		16,939	825	6,677	2,841	3,459	129	30,870		
31	ENERGY		1,223	67	636	283	328	36	2,573		
32	TRANSMISSION	3,015	1,610	77	634	270	324	12	2,927	88	0
33	DISTRIBUTION	16,142	10,012	615	3,162	999	377	962	16,127	15	0
34	DEMAND	11,894	7,055	377	2,924	988	372	166	11,882	12	0
35	CUSTOMER	4,248	2,955	239	238	11	6	796	4,245	3	0

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GULF POWER COMPANY
12 MONTHS ENDING DECEMBER 31, 2014
12/13 DEMAND ALLOCATION
SCHEDULE 2.40 - ANALYSIS OF OTHER WORKING CAPITAL
($000'S)

LINE NO. (1)	DESCRIPTION (2)	TOTAL ELECTRIC SYSTEM (3)	RATE CLASS RESIDENTIAL (4)	RATE CLASS GS (5)	RATE CLASS GSD/GSDT (6)	RATE CLASS LP/LPT (7)	RATE CLASS MAJOR ACCTS (8)	RATE CLASS OS (9)	TOTAL RETAIL SERVICE (10)	WHOLESALE (11)	UNIT POWER SALES (12)
36	CUSTOMER ACCOUNTS	9,660	8,406	635	382	10	17	132	9,582	78	0
37	CUSTOMER ASSISTANCE	10,185	6,649	1,349	1,713	253	221	0	10,185	0	0
38	CUSTOMER	10,185	6,649	1,349	1,713	253	221	0	10,185	0	0
39	ENERGY	0	0	0	0	0	0	0	0	0	0
40	TOTAL OTHER INVESTMENTS	73,473	44,837	3,569	13,204	4,656	4,727	1,271	72,264	1,209	0
41	DEMAND	46,807	25,604	1,279	10,235	4,099	4,155	307	45,679	1,128	0
42	CUSTOMER	24,093	18,010	2,223	2,333	274	244	928	24,012	81	0
43	ENERGY	2,573	1,223	67	636	283	328	36	2,573	0	0
44	ENVIRONMENTAL CLEANUP	58,878	34,098	2,423	10,227	4,844	3,705	1,117	56,414	1,047	1,417
45	DEMAND	40,536	21,460	1,074	8,584	3,428	3,426	262	38,234	885	1,417
46	CUSTOMER	15,950	11,192	1,252	1,246	1,265	117	823	15,895	55	0
47	ENERGY	924	410	21	243	109	127	14	924	0	0
48	REVENUE RELATED	1,469	1,036	76	154	42	35	18	1,361	107	0
49	PROP. INSURANCE RESERVE	(16,782)	(8,601)	(491)	(3,225)	(1,242)	(1,173)	(401)	(15,133)	(276)	(1,373)
50	DEMAND	(14,979)	(7,527)	(379)	(3,019)	(1,191)	(1,117)	(99)	(13,332)	(274)	(1,373)
51	CUSTOMER	(1,402)	(884)	(101)	(107)	(7)	(5)	(296)	(1,400)	(2)	0
52	ENERGY	(401)	(190)	(11)	(99)	(44)	(51)	(6)	(401)	0	0
	OTHER POST RETIREMENT BENEFITS										
53	PRODUCTION	(33,276)	(17,534)	(862)	(7,059)	(3,016)	(3,655)	(159)	(32,285)	(991)	0
	RETAIL JURISDICTION										
54	DEMAND		(16,353)	(797)	(8,446)	(2,743)	(3,338)	(125)	(29,802)		
55	ENERGY		(1,181)	(65)	(613)	(273)	(317)	(34)	(2,483)		
56	TRANSMISSION	(2,911)	(1,553)	(76)	(812)	(261)	(314)	(11)	(2,826)	(85)	0
57	DISTRIBUTION	(15,582)	(9,664)	(594)	(3,052)	(965)	(364)	(929)	(15,568)	(14)	0
58	DEMAND	(11,481)	(8,812)	(363)	(2,823)	(954)	(358)	(160)	(11,470)	(11)	0
59	CUSTOMER	(4,101)	(2,852)	(231)	(230)	(11)	(6)	(768)	(4,098)	(3)	0
60	CUSTOMER ACCOUNTS	(9,325)	(8,113)	(813)	(369)	(10)	(16)	(128)	(9,249)	(76)	0
61	CUSTOMER ASSISTANCE	(9,831)	(6,415)	(1,303)	(1,654)	(245)	(214)	0	(9,831)	0	0
62	CUSTOMER	(9,831)	(6,415)	(1,303)	(1,654)	(245)	(214)	0	(9,831)	0	0
63	ENERGY	0	0	0	0	0	0	0	0	0	0
64	TOTAL OTHER POST RETIREMENT BENEFITS	(70,925)	(43,279)	(3,447)	(12,747)	(4,497)	(4,563)	(1,226)	(69,759)	(1,166)	0
65	DEMAND	(45,185)	(24,718)	(1,235)	(9,881)	(3,958)	(4,010)	(296)	(44,098)	(1,087)	0
66	CUSTOMER	(23,257)	(17,380)	(2,147)	(2,253)	(266)	(236)	(896)	(23,178)	(79)	0
67	ENERGY	(2,483)	(1,181)	(85)	(613)	(273)	(317)	(34)	(2,483)	0	0
68	OTHER DEF. CR. & DEBITS	(44,453)	(25,747)	(1,828)	(7,721)	(3,657)	(2,797)	(842)	(42,592)	(791)	(1,070)
69	DEMAND	(30,604)	(16,202)	(811)	(6,481)	(2,588)	(2,586)	(198)	(28,866)	(668)	(1,070)
70	CUSTOMER	(12,042)	(8,450)	(945)	(941)	(955)	(88)	(621)	(12,000)	(42)	0
71	ENERGY	(697)	(311)	(15)	(183)	(83)	(96)	(9)	(697)	0	0
72	REVENUE RELATED	(1,109)	(784)	(57)	(116)	(31)	(27)	(14)	(1,029)	(81)	0
	UNAMORT. RATE CASE EXP.										
73	REVENUE RELATED	0	0	0	0	0	0	0	0	0	0
74	TOTAL OTHER WORK. CAP.	12,816	7,678	478	2,597	1,158	1,152	248	13,311	316	(1,011)
75	DEMAND	9,488	5,649	278	2,244	927	1,044	56	10,198	301	(1,011)
76	CUSTOMER	2,329	1,629	175	169	152	17	181	2,323	6	0
77	ENERGY	681	319	18	171	75	88	10	681	0	0
78	REVENUE RELATED	118	81	7	13	4	3	1	109	9	0

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GULF POWER COMPANY
12 MONTHS ENDED DECEMBER 31, 2014
12/13 DEMAND ALLOCATION
ANALYSIS OF OTHER WORKING CAPITAL

Line No.	Ftnt Label	Description
1	(A)	Allocated per Total Expenses less Production Energy related O & M, Income taxes, and Non-cash items.
2	(A)	
3	(A)	
4	(A)	
5	(A)	
6	(A)	
7	(A)	
8	(A)	
9	(A)	
10	(A)	
11	(B)	Allocated per corresponding Gross Plant; UPS directly assigned.
12	(C)	Allocated per corresponding Gross Plant.
13	(C)	
14	(B)	
15	(C)	
16	(C)	
17	(C)	
18	(D)	Allocated per corresponding Operations and Maintenance Expense.
19	(D)	
20	(D)	
21	(D)	
26	(E)	Allocated per Production Gross Plant; UPS directly assigned.
27	(F)	Allocated per corresponding Production Gross Plant.
28	(F)	
29	(G)	Allocated per corresponding Salaries and Wages
30	(G)	
31	(G)	
32	(G)	
33	(G)	
34	(G)	
35	(G)	
36	(G)	
37	(G)	
38	(G)	
39	(G)	

GULF POWER COMPANY
12 MONTHS ENDED DECEMBER 31, 2014
12/13 DEMAND ALLOCATION
ANALYSIS OF OTHER WORKING CAPITAL

Line No.	Ftnt Label	Description
44	(A)	
45	(A)	
46	(A)	
47	(A)	
48	(A)	
49	(H)	Allocated per Total Net Plant; UPS directly assigned.
50	(H)	
51	(I)	Allocated per Total Net Plant.
52	(I)	
53	(G)	
54	(G)	
55	(G)	
56	(G)	
57	(G)	
58	(G)	
59	(G)	
60	(G)	
61	(G)	
62	(G)	
63	(G)	
68	(A)	
69	(A)	
70	(A)	
71	(A)	
72	(A)	
73	(J)	Allocated per Retail Revenue from Sales.

GULF POWER COMPANY
12 MONTHS ENDING DECEMBER 31, 2014
12/13 DEMAND ALLOCATION
SCHEDULE 2.50 - ANALYSIS OF OTHER RATE BASE ITEMS
($000'S)

LINE NO. (1)	DESCRIPTION (2)	TOTAL ELECTRIC SYSTEM (3)	RATE CLASS RESIDENTIAL (4)	RATE CLASS GS (5)	RATE CLASS GSD/GSDT (6)	RATE CLASS LP/LPT (7)	RATE CLASS MAJOR ACCTS (8)	RATE CLASS OS (9)	TOTAL RETAIL SERVICE (10)	WHOLESALE (11)	UNIT POWER SALES (12)
	CONST. WORK IN PROGRESS INTEREST BEARING										
1	PRODUCTION	0	0	0	0	0	0	0	0	0	0
	RETAIL JURISDICTION										
2	DEMAND		0	0	0	0	0	0	0		
3	ENERGY		0	0	0	0	0	0	0		
4	TRANSMISSION	0	0	0	0	0	0	0	0	0	0
5	DISTRIBUTION	0	0	0	0	0	0	0	0	0	0
6	DEMAND	0	0	0	0	0	0	0	0	0	0
7	CUSTOMER	0	0	0	0	0	0	0	0	0	0
8	CUSTOMER ACCOUNTS	0	0	0	0	0	0	0	0	0	0
9	CUSTOMER ASSISTANCE	0	0	0	0	0	0	0	0	0	0
10	CUSTOMER	0	0	0	0	0	0	0	0	0	0
11	ENERGY	0	0	0	0	0	0	0	0	0	0
12	TOTAL CWIP	0	0	0	0	0	0	0	0	0	0
13	DEMAND	0	0	0	0	0	0	0	0	0	0
14	CUSTOMER	0	0	0	0	0	0	0	0	0	0
15	ENERGY	0	0	0	0	0	0	0	0	0	0
	CONST. WORK IN PROGRESS WORK NOT BEARING INTEREST										
16	PRODUCTION	17,325	5,673	279	2,285	976	1,182	52	10,447	321	6,557
	RETAIL JURISDICTION										
17	DEMAND		5,290	258	2,086	888	1,080	41	9,643		
18	ENERGY		383	21	199	88	102	11	804		
19	TRANSMISSION	10,704	5,753	280	2,267	953	1,115	44	10,412	292	0
20	DISTRIBUTION	5,818	3,417	210	1,184	398	201	387	5,797	21	0
21	DEMAND	4,661	2,723	144	1,120	398	199	56	4,640	21	0
22	CUSTOMER	1,157	694	66	64	2	2	329	1,157	0	0
23	TOTAL CWIP - WORK NOT BEARING INTEREST	33,847	14,843	769	5,736	2,327	2,498	483	26,656	634	6,557
24	DEMAND	31,886	13,766	682	5,473	2,237	2,394	143	24,695	634	6,557
25	CUSTOMER	1,157	694	66	64	2	2	329	1,157	0	0
26	ENERGY	804	383	21	199	88	102	11	804	0	0
	PLANT HELD FOR FUTURE USE										
27	PRODUCTION	5,280	2,785	136	1,120	478	579	25	5,123	157	0
	RETAIL JURISDICTION										
28	DEMAND		2,596	126	1,023	435	529	20	4,729		
29	ENERGY		189	10	97	43	50	5	394		
	DISTRIBUTION										
30	DEMAND	18	10	1	4	2	1	0	18	0	0
31	CUSTOMER	4	3	0	0	0	0	1	4	0	0
32	TOTAL DISTRIBUTION	22	13	1	4	2	1	1	22	0	0
	GENERAL										
33	DEMAND	85	48	2	18	7	7	1	83	2	0
34	CUSTOMER	44	33	4	4	1	0	2	44	0	0
35	ENERGY	4	2	0	2	0	1	(1)	4	0	0
36	TOTAL GENERAL	133	83	6	24	8	8	2	131	2	0
37	TOTAL PLNT HELD FOR FUT. USE	5,435	2,881	143	1,148	488	588	28	5,276	159	0
38	DEMAND	4,989	2,654	129	1,045	444	537	21	4,830	159	0
39	CUSTOMER	48	36	4	4	1	0	3	48	0	0
40	ENERGY	398	191	10	99	43	51	4	398	0	0

GULF POWER COMPANY
12 MONTHS ENDING DECEMBER 31, 2014
12/13 DEMAND ALLOCATION
SCHEDULE 2.50 - ANALYSIS OF OTHER RATE BASE ITEMS
($000'S)

LINE NO. (1)	DESCRIPTION (2)	TOTAL ELECTRIC SYSTEM (3)	RATE CLASS RESIDENTIAL (4)	RATE CLASS GS (5)	RATE CLASS GSD/GSDT (6)	RATE CLASS LP/LPT (7)	RATE CLASS MAJOR ACCTS (8)	RATE CLASS OS (9)	TOTAL RETAIL SERVICE (10)	WHOLESALE (11)	UNIT POWER SALES (12)
	INJURIES & DAMAGES RESERVE										
41	PRODUCTION	(1,626)	(804)	(40)	(324)	(139)	(167)	(8)	(1,482)	(46)	(98)
	RETAIL JURISDICTION										
42	DEMAND		(750)	(37)	(296)	(126)	(153)	(6)	(1,368)		
43	ENERGY		(54)	(3)	(28)	(13)	(14)	(2)	(114)		
44	TRANSMISSION	(134)	(72)	(3)	(28)	(12)	(14)	(1)	(130)	(4)	0
45	DISTRIBUTION	(715)	(443)	(27)	(140)	(44)	(17)	(43)	(714)	(1)	0
46	DEMAND	(527)	(311)	(17)	(130)	(44)	(17)	(7)	(526)	(1)	0
47	CUSTOMER	(188)	(132)	(10)	(10)	0	0	(36)	(188)	0	0
48	CUSTOMER ACCOUNTS	(428)	(374)	(28)	(17)	0	0	(6)	(425)	(3)	0
49	CUSTOMER ASSISTANCE	(451)	(294)	(60)	(76)	(11)	(10)	0	(451)	0	0
50	CUSTOMER	(451)	(294)	(60)	(76)	(11)	(10)	0	(451)	0	0
51	ENERGY	0	0	0	0	0	0	0	0	0	0
52	TOTAL INJ. & DAM. RES.	(3,354)	(1,987)	(158)	(585)	(206)	(208)	(58)	(3,202)	(54)	(98)
53	DEMAND	(2,173)	(1,133)	(57)	(454)	(182)	(184)	(14)	(2,024)	(51)	(98)
54	CUSTOMER	(1,067)	(800)	(98)	(103)	(11)	(10)	(42)	(1,064)	(3)	0
55	ENERGY	(114)	(54)	(3)	(28)	(13)	(14)	(2)	(114)	0	0
	UNAMORT. PLANT ACQ. ADJ.										
56	PRODUCTION	1,852	0	0	0	0	0	0	0	0	1,852
	RETAIL JURISDICTION										
57	DEMAND		0	0	0	0	0	0	0		
58	ENERGY		0	0	0	0	0	0	0		
59	TRANSMISSION	51	0	0	0	0	0	0	0	0	51
60	DISTRIBUTION	0	0	0	0	0	0	0	0	0	0
61	DEMAND	0	0	0	0	0	0	0	0	0	0
62	CUSTOMER	0	0	0	0	0	0	0	0	0	0
63	TOTAL UNAMORT PLNT ACQ. ADJ.	1,903	0	0	0	0	0	0	0	0	1,903
64	DEMAND	1,903	0	0	0	0	0	0	0	0	1,903
65	CUSTOMER	0	0	0	0	0	0	0	0	0	0
66	ENERGY	0	0	0	0	0	0	0	0	0	0
67	CUSTOMER ADVANCES FOR CONST.	0	0	0	0	0	0	0	0	0	0
68	TOTAL OTHER ADDITIONS	37,831	15,737	754	6,299	2,609	2,878	453	28,730	739	8,362
69	DEMAND	36,605	15,287	754	6,064	2,499	2,747	150	27,501	742	8,362
70	CUSTOMER	138	(70)	(28)	(35)	(8)	(8)	290	141	(3)	0
71	ENERGY	1,088	520	28	270	118	139	13	1,088	0	0

GULF POWER COMPANY
12 MONTHS ENDED DECEMBER 31, 2014
12/13 DEMAND ALLOCATION
ANALYSIS OF OTHER RATE BASE ITEMS

Line No.	Ftnt Label	Description
1	(A)	Functional totals provided by Gulf Power Company. Allocated per corresponding Gross Plant excluding UPS; UPS directly assigned.
2	(B)	Functional totals provided by Gulf Power Company. Allocated per corresponding Gross Plant.
3	(B)	
4	(B)	
5	(B)	
6	(B)	
7	(B)	
8	(C)	Allocated per corresponding Operations and Maintenance expense.
9	(C)	
10	(C)	
11	(C)	
16	(A)	
17	(B)	
18	(B)	
19	(B)	
20	(B)	
21	(B)	
22	(B)	
27	(B)	
28	(B)	
29	(B)	
30	(B)	
31	(B)	
33	(B)	
34	(B)	
35	(B)	
41	(D)	Allocated per Total Salaries and Wages, including UPS Production Salaries and Wages of $2,434.
42	(E)	Allocated per corresponding Salaries and Wages.
43	(E)	
44	(D)	
45	(E)	
46	(E)	
47	(E)	
48	(E)	
49	(E)	
50	(E)	
51	(E)	
56	(A)	
57	(B)	
58	(B)	
59	(A)	
60	(B)	
61	(B)	
62	(B)	
67	(F)	Specific Assignment.

GULF POWER COMPANY
12 MONTHS ENDING DECEMBER 31, 2014
12/13 DEMAND ALLOCATION
SCHEDULE 3.00 - ANALYSIS OF REVENUES
($000'S)

LINE NO. (1)	DESCRIPTION (2)	TOTAL ELECTRIC SYSTEM (3)	RATE CLASS RESIDENTIAL (4)	RATE CLASS GS (5)	RATE CLASS GSD/GSDT (6)	RATE CLASS LP/LPT (7)	RATE CLASS MAJOR ACCTS (8)	RATE CLASS OS (9)	TOTAL RETAIL SERVICE (10)	WHOLESALE (11)	UNIT POWER SALES (12)
	REVENUE FROM SALES										
1	BASE RATE REV. FROM SALES	510,734	296,890	20,537	102,785	33,933	29,452	14,896	496,493	12,241	0
2	FUEL, ECCR, PPCC, ECRC REVENUES	0	0	0	0	0	0	0	0	0	0
3	NET REVENUE EXCLUDING FUEL	510,734	296,890	20,537	102,785	33,933	29,452	14,896	498,493	12,241	0
	OTHER OPERATING REVENUES										
	451-MISC. SERVICE REVENUES										
4	RESTORATION FEE	1,213	1,174	31	8	0	0	0	1,213	0	0
5	AFTER HOURS FEE	116	115	1	0	0	0	0	116	0	0
6	INACCURATE METER FEE	26	19	2	5	0	0	0	28	0	0
7	RECONNECTION FEE	2,823	2,696	84	43	0	0	0	2,823	0	0
8	FRANCHISE FEES	42,247	25,162	1,740	8,711	2,876	2,496	1,262	42,247	0	0
9	INSTALL. & REM.-TEMP SERV	0	0	0	0	0	0	0	0	0	0
10	CONNECTION FEES	92	77	13	2	0	0	0	92	0	0
11	COLLECTION CHARGES	207	161	24	22	0	0	0	207	0	0
12	INVESTIGATIVE CHARGES	40	38	2	0	0	0	0	40	0	0
13	RETURN CHECK CHARGE	272	258	6	6	0	0	0	272	0	0
14	TOTAL ACCOUNT 451	47,036	29,700	1,903	8,799	2,876	2,496	1,262	47,036	0	0
	454-RENT FROM ELEC. PROP.										
15	EQUIPMENT RENTAL	1,686	1,045	57	435	119	3	27	1,686	0	0
16	METER TREATER RENTAL	253	244	7	2	0	0	0	253	0	0
17	POLE ATTACHMENT RENTAL	3,110	1,841	99	768	263	92	47	3,110	0	0
18	MICROWAVE TRANSPORT	730	446	35	131	46	47	13	716	12	0
19	RENT FROM PLANT DANIEL	40	22	1	8	4	4	0	39	1	0
20	MISCELLANEOUS RENTS	518	315	25	93	33	33	9	508	8	0
21	TOTAL ACCOUNT 454	6,335	3,913	224	1,437	465	179	96	6,314	21	0
22	455-INTERDEPART. RENTAL	0	0	0	0	0	0	0	0	0	0
23	456-OTHER ELECTRIC REVENUES	6,368	3,390	165	1,336	569	692	26	6,178	190	0
24	456-GULF POWER ENERGY SERVICES REVENUES	5,632	0	0	0	5,632	0	0	5,632	0	0
25	456 - FPU SERVICE PAYMENTS	3,678	0	0	0	0	0	0	0	3,678	0
26	456 - BLOUNTSTOWN SERVICE PAYMENTS	122	85	3	26	11	13	0	118	4	0
27	TOTAL ACCOUNT 456	15,800	3,455	168	1,362	6,212	705	26	11,928	3,872	0
28	REV. NONASSOC. CO.-DEMAND	51,950	0	0	0	0	0	0	0	0	51,950
29	REV. NONASSOC. CO.-ENERGY	13,652	3,389	168	1,760	784	907	99	7,127	214	6,311
30	TOTAL REV. NONASSOC. CO.	65,602	3,389	188	1,760	784	907	99	7,127	214	58,261
31	TOTAL OTHER OPER. REVENUE	134,773	40,457	2,483	13,358	10,337	4,287	1,483	72,405	4,107	58,261
	ADJUSTMENTS TO REVENUES										
32	FRANCHISE FEE REVENUES	(42,247)	(25,162)	(1,740)	(8,711)	(2,876)	(2,496)	(1,262)	(42,247)	(0)	0
33	NET ADJUSTMENT TO REVENUES	(42,247)	(25,162)	(1,740)	(8,711)	(2,876)	(2,496)	(1,262)	(42,247)	(0)	0
34	TOTAL ADJUSTED REVENUES	603,260	312,185	21,280	107,432	41,394	31,243	15,117	528,651	16,348	58,261

GULF POWER COMPANY
12 MONTHS ENDED DECEMBER 31, 2014
12/13 DEMAND ALLOCATION
ANALYSIS OF REVENUES

Line No.	Ftnt Label	Description
1	(A)	Provided by Gulf Power Company.
2	(B)	Allocated per Retail MWH Sales.
4	(A)	
5	(A)	
6	(A)	
7	(A)	
8	(C)	Allocated per retail revenue from sales.
9	(A)	
10	(A)	
11	(A)	
12	(A)	
13	(A)	
15	(D)	Allocated per Level 5 Demand Allocator
16	(A)	
17	(E)	Allocated per Distribution Gross Plant in Account 364.
18	(F)	Allocated per Total Salaries and Wages.
19	(G)	Allocated per Level 2 Demand Allocator; UPS directly assigned.
20	(F)	
22	(F)	
23	(G)	
24	(H)	Provided by Gulf Power Company and assigned to Rate Class LP/LPT.
25	(I)	Assigned to FPU.
26	(G)	
28	(G)	
29	(J)	Allocated per Level 1 Energy Allocator; UPS directly assigned.
32	(C)	

GULF POWER COMPANY
12 MONTHS ENDING DECEMBER 31, 2014
12/13 DEMAND ALLOCATION
SCHEDULE 4.10 - ANALYSIS OF OPERATIONS AND MAINTENANCE EXPENSE
($000'S)

LINE NO. (1)	DESCRIPTION (2)	TOTAL ELECTRIC SYSTEM (3)	RATE CLASS RESIDENTIAL (4)	RATE CLASS GS (5)	RATE CLASS GSD/GSDT (6)	RATE CLASS LP/LPT (7)	RATE CLASS MAJOR ACCTS (8)	RATE CLASS OS (9)	TOTAL RETAIL SERVICE (10)	WHOLESALE (11)	UNIT POWER SALES (12)
	PRODUCTION O & M EXPENSES										
	STEAM POWER GENERATION										
	OPERATIONS										
1	500-SUPERVISION	11,719	6,087	297	2,400	1,021	1,244	47	11,096	341	282
2	501-ENERGY RELATED	310,081	127,134	7,034	66,006	29,382	33,974	3,709	267,239	8,028	34,814
3	501-FUEL REMOVAL	(303,538)	(124,330)	(6,879)	(64,550)	(28,734)	(33,224)	(3,627)	(261,344)	(7,851)	(34,343)
4	501-NET	6,543	2,804	155	1,456	648	750	82	5,895	177	471
	502-STEAM										
5	DEMAND RELATED	2,508	1,171	57	462	197	240	9	2,136	66	306
6	ENERGY RELATED	5,763	2,193	121	1,139	507	586	64	4,610	139	1,014
7	TOTAL ACCOUNT 502	8,271	3,364	178	1,601	704	826	73	6,746	205	1,320
	505-ELECTRIC EXPENSES										
8	DEMAND RELATED	2,946	1,472	72	580	247	301	11	2,683	82	181
9	ENERGY RELATED	1,185	533	30	278	124	143	16	1,124	34	27
10	TOTAL ACCOUNT 505	4,131	2,005	102	858	371	444	27	3,807	116	208
	506-MISCELLANEOUS										
11	DEMAND RELATED	15,224	7,666	374	3,022	1,286	1,565	59	13,972	429	823
12	ENERGY RELATED	0	0	0	0	0	0	0	0	0	0
13	TOTAL ACCOUNT 506	15,224	7,666	374	3,022	1,286	1,565	59	13,972	429	823
14	507-RENTS	0	0	0	0	0	0	0	0	0	0
15	509-ALLOWANCES	0	0	0	0	0	0	0	0	0	0
16	TOTAL STEAM OPERATIONS	45,888	21,926	1,106	9,337	4,030	4,829	288	41,516	1,268	3,104
	MAINTENANCE										
17	510-SUPERVISION	9,886	4,915	240	1,938	825	1,004	38	8,960	275	651
18	511-STRUCTURES	5,707	2,864	139	1,128	480	584	22	5,217	160	330
	512-BOILER PLANT										
19	DEMAND RELATED	3,490	1,577	77	622	265	322	12	2,875	86	527
20	ENERGY RELATED	25,255	9,588	531	4,979	2,216	2,562	280	20,156	606	4,493
21	TOTAL ACCOUNT 512	28,745	11,165	608	5,601	2,481	2,884	292	23,031	694	5,020
	513-ELECTRIC PLANT										
22	DEMAND RELATED	1,340	701	34	276	118	144	5	1,278	39	23
23	ENERGY RELATED	7,097	2,962	164	1,538	684	791	86	6,225	187	685
24	TOTAL ACCOUNT 513	8,437	3,663	198	1,814	802	935	91	7,503	226	708

GULF POWER COMPANY
12 MONTHS ENDING DECEMBER 31, 2014
12/13 DEMAND ALLOCATION
SCHEDULE 4.10 - ANALYSIS OF OPERATIONS AND MAINTENANCE EXPENSE
($000'S)

LINE NO. (1)	DESCRIPTION (2)	TOTAL ELECTRIC SYSTEM (3)	RATE CLASS RESIDENTIAL (4)	RATE CLASS GS (5)	RATE CLASS GSD/GSDT (6)	RATE CLASS LP/LPT (7)	RATE CLASS MAJOR ACCTS (8)	RATE CLASS OS (9)	TOTAL RETAIL SERVICE (10)	WHOLESALE (11)	UNIT POWER SALES (12)
	514-MISCELLANEOUS										
25	DEMAND RELATED	3,132	1,529	75	603	257	312	12	2,788	86	258
26	ENERGY RELATED	0	0	0	0	0	0	0	0	0	0
27	TOTAL ACCOUNT 514	3,132	1,529	75	603	257	312	12	2,788	86	258
28	TOTAL MAINTENANCE	55,907	24,138	1,260	11,084	4,845	5,719	455	47,499	1,441	6,957
29	TOTAL STEAM POWER GENERATION	101,795	46,062	2,366	20,421	8,875	10,548	743	89,015	2,709	10,071
	OTHER POWER GENERATION										
	OPERATION										
30	546-SUPERVISION	1,701	905	44	357	152	185	7	1,650	51	0
31	547-ENERGY RELATED	580	267	15	139	62	72	8	563	17	0
32	547-FUEL	310,241	143,287	7,928	74,392	33,115	38,291	4,180	301,193	9,048	0
33	547-FUEL REMOVAL	(310,241)	(143,287)	(7,928)	(74,392)	(33,115)	(38,291)	(4,180)	(301,193)	(9,048)	0
34	547-NET FUEL	0	0	0	0	0	0	0	0	0	0
	548-GENERATION EXPENSES										
35	DEMAND	528	281	14	111	47	57	2	512	16	0
36	ENERGY	0	0	0	0	0	0	0	0	0	0
37	TOTAL ACCOUNT 548	528	281	14	111	47	57	2	512	16	0
	549-MISCELLANEOUS PLANT										
38	DEMAND	848	452	22	178	76	92	3	823	25	0
39	ENERGY	0	0	0	0	0	0	0	0	0	0
40	TOTAL ACCOUNT 549	848	452	22	178	76	92	3	823	25	0
41	TOTAL OPERATION	3,657	1,905	95	785	337	406	20	3,548	109	0
	MAINTENANCE										
42	551-SUPERVISION	296	157	8	62	26	33	1	287	9	0
	552-STRUCTURES										
43	DEMAND	0	0	0	0	0	0	0	0	0	0
44	ENERGY	0	0	0	0	0	0	0	0	0	0
45	TOTAL ACCOUNT 552	0	0	0	0	0	0	0	0	0	0

GULF POWER COMPANY
12 MONTHS ENDING DECEMBER 31, 2014
12/13 DEMAND ALLOCATION
SCHEDULE 4.10 - ANALYSIS OF OPERATIONS AND MAINTENANCE EXPENSE
($000'S)

LINE NO. (1)	DESCRIPTION (2)	TOTAL ELECTRIC SYSTEM (3)	RATE CLASS RESIDENTIAL (4)	RATE CLASS GS (5)	RATE CLASS GSD/GSDT (6)	RATE CLASS LP/LPT (7)	RATE CLASS MAJOR ACCTS (8)	RATE CLASS OS (9)	TOTAL RETAIL SERVICE (10)	WHOLESALE (11)	UNIT POWER SALES (12)
	553-ELECTRIC PLANT										
46	DEMAND	6,665	3,547	173	1,399	595	725	27	6,466	199	0
47	ENERGY	0	0	0	0	0	0	0	0	0	0
48	TOTAL ACCOUNT 553	6,665	3,547	173	1,399	595	725	27	6,466	199	0
	554-MISCELLANEOUS PLANT										
49	DEMAND	524	278	14	110	47	57	2	508	16	0
50	ENERGY	0	0	0	0	0	0	0	0	0	0
51	TOTAL ACCOUNT 554	524	278	14	110	47	57	2	508	16	0
52	TOTAL MAINTENANCE	7,485	3,982	195	1,571	668	815	30	7,261	224	0
53	TOTAL OTHER GEN. EXPENSE	11,142	5,887	290	2,356	1,005	1,221	50	10,809	333	0
54	TOTAL GENERATION EXPENSES	112,937	51,949	2,656	22,777	9,880	11,769	793	99,824	3,042	10,071
55	DEMAND	66,514	33,602	1,640	13,248	5,639	6,865	257	61,251	1,882	3,381
56	ENERGY	46,423	18,347	1,016	9,529	4,241	4,904	536	38,573	1,160	6,690
	OTHER PRODUCTION EXPENSE										
57	555-PURCHASED POWER	35,992	15,278	845	7,932	3,531	4,083	446	32,113	965	2,914
58	DEMAND	0	0	0	0	0	0	0	0	0	0
59	ENERGY	35,992	15,278	845	7,932	3,531	4,083	446	32,113	965	2,914
60	FUEL REMOVAL	(35,992)	(15,276)	(845)	(7,932)	(3,531)	(4,083)	(446)	(32,113)	(965)	(2,914)
61	NET ENERGY	0	0	0	0	0	0	0	0	0	0
62	NET TOTAL ACCOUNT 555	0	0	0	0	0	0	0	0	0	0
	556-SYSTEM CONTROL										
63	DEMAND	1,817	968	47	381	162	198	7	1,763	54	0
64	ENERGY	0	0	0	0	0	0	0	0	0	0
65	TOTAL ACCOUNT 556	1,817	968	47	381	182	198	7	1,763	54	0
	557-OTHER EXPENSES										
66	DEMAND	2,054	1,095	53	431	183	223	8	1,993	61	0
67	ENERGY	0	0	0	0	0	0	0	0	0	0
68	TOTAL ACCOUNT 557	2,054	1,095	53	431	183	223	8	1,993	61	0
69	TOTAL OTHER PROD. EXPENSE	3,871	2,063	100	812	345	421	15	3,756	115	0
70	DEMAND	3,871	2,063	100	812	345	421	15	3,756	115	0
71	ENERGY	0	0	0	0	0	0	0	0	0	0
72	TOTAL PRODUCTION EXPENSES	116,808	54,012	2,756	23,589	10,225	12,190	808	103,580	3,157	10,071
73	DEMAND	70,385	35,665	1,740	14,060	5,984	7,286	272	65,007	1,997	3,381
74	ENERGY	46,423	18,347	1,016	9,529	4,241	4,904	536	38,573	1,160	6,690

GULF POWER COMPANY
12 MONTHS ENDING DECEMBER 31, 2014
12/13 DEMAND ALLOCATION
SCHEDULE 4.10 - ANALYSIS OF OPERATIONS AND MAINTENANCE EXPENSE
($000'S)

LINE NO. (1)	DESCRIPTION (2)	TOTAL ELECTRIC SYSTEM (3)	RATE CLASS RESIDENTIAL (4)	RATE CLASS GS (5)	RATE CLASS GSD/GSDT (6)	RATE CLASS LP/LPT (7)	RATE CLASS MAJOR ACCTS (8)	RATE CLASS OS (9)	TOTAL RETAIL SERVICE (10)	WHOLESALE (11)	UNIT POWER SALES (12)
	TRANSMISSION O & M EXPENSE										
	OPERATION										
75	561-LOAD DISPATCHING	3,526	1,877	91	739	315	383	14	3,419	105	2
76	562-STATION	43	24	1	9	4	4	0	42	1	0
77	563-OVERHEAD LINES	191	101	5	40	17	21	1	185	6	0
78	564-UNDERGROUND LINES	0	0	0	0	0	0	0	0	0	0
79	565-TRANS. OF ELEC. BY OTHERS	(301)	(160)	(8)	(63)	(27)	(33)	(1)	(292)	(9)	0
80	SUBTOTAL	3,459	1,842	89	725	309	375	14	3,354	103	2
81	560-SUPERVISION	1,609	856	41	337	144	175	7	1,560	48	1
82	566-MISCELLANEOUS	1,038	552	27	217	93	113	4	1,006	31	1
83	567-RENTS	165	87	4	35	15	18	1	160	5	0
84	TOTAL OPERATIONS	6,271	3,337	161	1,314	561	681	26	6,080	187	4
	MAINTENANCE										
85	569-STRUCTURES	1,003	533	26	211	90	109	4	973	30	0
86	570-STATION EQUIPMENT	830	454	22	179	74	79	3	811	19	0
87	571-OVERHEAD LINES	4,479	2,385	116	940	400	486	18	4,345	134	0
88	SUBTOTAL	6,312	3,372	164	1,330	564	874	25	6,129	183	0
89	568-SUPERVISION	1,052	561	27	222	94	113	4	1,021	31	0
90	573-MISCELLANEOUS	102	56	3	21	9	10	0	99	3	0
91	TOTAL MAINTENANCE	7,466	3,989	194	1,573	667	797	29	7,249	217	0
92	TOTAL TRANSMISSION EXPENSE	13,737	7,326	355	2,887	1,228	1,478	55	13,329	404	4
	DISTRIBUTION O & M EXPENSE										
	OPERATIONS										
93	581-LOAD DISPATCHING	902	536	26	211	78	47	4	902	0	0
94	582-STATION	308	166	8	66	30	32	1	303	5	0

GULF POWER COMPANY
12 MONTHS ENDING DECEMBER 31, 2014
12/13 DEMAND ALLOCATION
SCHEDULE 4.10 - ANALYSIS OF OPERATIONS AND MAINTENANCE EXPENSE
($000'S)

LINE NO. (1)	DESCRIPTION (2)	TOTAL ELECTRIC SYSTEM (3)	RATE CLASS RESIDENTIAL (4)	RATE CLASS GS (5)	RATE CLASS GSD/GSDT (6)	RATE CLASS LP/LPT (7)	RATE CLASS MAJOR ACCTS (8)	RATE CLASS OS (9)	TOTAL RETAIL SERVICE (10)	WHOLESALE (11)	UNIT POWER SALES (12)
	583-OVERHEAD LINES										
95	DEMAND	2,579	1,565	85	650	199	40	40	2,579	0	0
96	CUSTOMER	0	(1)	0	1	0	0	0	0	0	0
97	TOTAL ACCOUNT 583	2,579	1,564	85	651	199	40	40	2,579	0	0
	584-UNDERGROUND LINES										
98	DEMAND	739	447	24	188	57	11	12	739	0	0
99	CUSTOMER	0	1	0	(1)	0	0	0	0	0	0
100	TOTAL ACCOUNT 584	739	448	24	187	57	11	12	739	0	0
101	586-STREET LIGHTING	598	0	0	0	0	0	598	598	0	0
102	586-METER	1,453	1,090	144	196	11	6	3	1,450	3	0
103	586-OTHER MISC. REVS.	1,174	1,118	38	18	0	0	0	1,174	0	0
104	TOTAL ACCOUNT 586	2,627	2,208	182	214	11	6	3	2,624	3	0
105	587-CUSTOMER INSTAL.	1,306	1,164	88	53	1	0	0	1,306	0	0
106	587-OTHER MISC. REVS.	25	24	1	0	0	0	0	25	0	0
107	TOTAL ACCOUNT 587	1,331	1,188	89	53	1	0	0	1,331	0	0
108	SUBTOTAL	9,084	6,110	414	1,382	376	136	658	9,076	8	0
109	DEMAND	4,628	2,714	143	1,115	364	130	57	4,523	5	0
110	CUSTOMER	4,556	3,396	271	267	12	6	601	4,553	3	0
	580-SUPERVISION										
111	DEMAND	3,374	2,022	107	831	271	97	42	3,370	4	0
112	CUSTOMER	3,394	2,530	202	199	9	4	448	3,392	2	0
113	TOTAL ACCOUNT 580	6,768	4,552	309	1,030	280	101	490	6,762	6	0
	588-MISCELLANEOUS										
114	DEMAND	2,175	1,305	69	535	175	62	27	2,173	2	0
115	CUSTOMER	2,188	1,632	130	128	6	2	289	2,187	1	0
116	TOTAL ACCOUNT 588	4,363	2,937	199	663	181	64	316	4,360	3	0
	589-RENTS										
117	DEMAND	0	0	0	0	0	0	0	0	0	0
118	CUSTOMER	0	0	0	0	0	0	0	0	0	0
119	TOTAL ACCOUNT 589	0	0	0	0	0	0	0	0	0	0
120	TOTAL OPERATION	20,215	13,599	922	3,075	837	301	1,464	20,198	17	0
	MAINTENANCE										
121	591-STRUCTURES	28	15	1	6	3	2	0	27	1	0
122	592-STATION EQUIPMENT	962	518	25	205	94	100	4	946	16	0

GULF POWER COMPANY
12 MONTHS ENDING DECEMBER 31, 2014
12/13 DEMAND ALLOCATION
SCHEDULE 4.10 - ANALYSIS OF OPERATIONS AND MAINTENANCE EXPENSE
($000'S)

LINE NO. (1)	DESCRIPTION (2)	TOTAL ELECTRIC SYSTEM (3)	RATE CLASS RESIDENTIAL (4)	RATE CLASS GS (5)	RATE CLASS GSD/GSDT (6)	RATE CLASS LP/LPT (7)	RATE CLASS MAJOR ACCTS (8)	RATE CLASS OS (9)	TOTAL RETAIL SERVICE (10)	WHOLESALE (11)	UNIT POWER SALES (12)
123	593-OVHD LINES - MISC REVS	0	0	0	0	0	0	0	0	0	0
	593-OVERHEAD LINES										
124	DEMAND	13,075	7,735	418	3,229	1,105	389	199	13,075	0	0
125	CUSTOMER	0	0	0	0	0	0	0	0	0	0
126	SUBTOTAL OVERHEAD LINES	13,075	7,735	418	3,229	1,105	389	199	13,075	0	0
127	TOTAL ACCOUNT 593	13,075	7,735	418	3,229	1,105	389	199	13,075	0	0
	594-UNDERGROUND LINES										
128	DEMAND	1,897	1,127	61	470	156	52	29	1,897	0	0
129	CUSTOMER	0	0	0	0	0	0	0	0	0	0
130	TOTAL ACCOUNT 594	1,897	1,127	61	470	156	52	29	1,897	0	0
	595-LINE TRANSFORMERS										
131	DEMAND	1,001	616	33	256	73	7	16	1,001	0	0
132	CUSTOMER	0	0	0	0	0	0	0	0	0	0
133	TOTAL ACCOUNT 595	1,001	616	33	256	73	7	16	1,001	0	0
134	596-STREET LIGHTING	597	0	0	0	0	0	597	597	0	0
135	597-METERS	159	121	16	21	1	0	0	159	0	0
136	SUBTOTAL	17,719	10,132	554	4,187	1,434	550	845	17,702	17	0
137	DEMAND	16,963	10,011	538	4,166	1,433	550	248	16,946	17	0
138	CUSTOMER	756	121	16	21	1	0	597	756	0	0
	590-SUPERVISION										
139	DEMAND	3,508	2,071	111	862	296	113	51	3,504	4	0
140	CUSTOMER	156	26	3	4	0	0	123	156	0	0
141	TOTAL ACCOUNT 590	3,664	2,097	114	866	296	113	174	3,660	4	0
	598-MISCELLANEOUS										
142	DEMAND	452	268	14	111	38	14	7	452	0	0
143	CUSTOMER	20	3	0	1	0	0	16	20	0	0
144	TOTAL ACCOUNT 598	472	271	14	112	38	14	23	472	0	0
145	TOTAL MAINTENANCE	21,855	12,500	682	5,165	1,768	677	1,042	21,834	21	0
146	TOTAL DISTRIBUTION EXPENSE	42,070	26,099	1,604	8,240	2,605	978	2,506	42,032	38	0
147	TOTAL DEMAND	31,000	18,391	982	7,620	2,577	966	432	30,968	32	0
148	TOTAL CUSTOMER	11,070	7,708	622	620	28	12	2,074	11,064	6	0
149	CUSTOMER ACCOUNTS EXPENSE	21,986	19,131	1,446	869	22	38	301	21,807	179	0

GULF POWER COMPANY
12 MONTHS ENDING DECEMBER 31, 2014
12/13 DEMAND ALLOCATION
SCHEDULE 4.10 - ANALYSIS OF OPERATIONS AND MAINTENANCE EXPENSE
($000'S)

LINE NO. (1)	DESCRIPTION (2)	TOTAL ELECTRIC SYSTEM (3)	RATE CLASS RESIDENTIAL (4)	RATE CLASS GS (5)	RATE CLASS GSD/GSDT (6)	RATE CLASS LP/LPT (7)	RATE CLASS MAJOR ACCTS (8)	RATE CLASS OS (9)	TOTAL RETAIL SERVICE (10)	WHOLESALE (11)	UNIT POWER SALES (12)
	CUSTOMER ASSISTANCE EXPENSE										
150	907/911-SUPERVISION	1,829	1,603	141	84	1	0	0	1,829	0	0
	908/912-CUSTOMER ASSISTANCE										
151	RESIDENTIAL	5,080	5,080	0	0	0	0	0	5,080	0	0
152	COMMERCIAL	2,093	0	1,305	776	11	1	0	2,093	0	0
153	TOTAL INDUSTRIAL	7,391	0	145	1,121	5,874	251	0	7,391	0	0
154	INDUSTRIAL - GULF POWER ENERGY SRVS	5,597	0	0	0	5,597	0	0	5,597	0	0
155	NET INDUSTRIAL OF GULF POWER ENERGY SRVS	1,794	0	145	1,121	277	251	0	1,794	0	0
156	STREET LIGHTING	0	0	0	0	0	0	0	0	0	0
157	TOTAL ACCOUNT 908/912	14,564	5,080	1,450	1,897	5,885	252	0	14,564	0	0
158	909/913-ADVERTISING	1,232	1,125	13	65	15	14	0	1,232	0	0
159	910-MISCELLANEOUS	190	166	15	9	0	0	0	190	0	0
160	ENERGY CONSERVATION	21,933	19,377	1,357	1,058	78	63	0	21,933	0	0
161	ECCR ADJUSTMENT	(21,933)	(19,377)	(1,357)	(1,058)	(78)	(63)	0	(21,933)	0	0
162	NET ENERGY COST CONSER.	0	0	0	0	0	0	0	0	0	0
163	TOTAL CUSTOMER ASSISTANCE	17,815	7,974	1,619	2,055	5,901	266	0	17,815	0	0
	ADMIN. & GENERAL EXPENSE										
	924-PROPERTY INSURANCE										
164	PRODUCTION	4,309	2,147	105	863	368	446	19	3,948	128	233
	RETAIL JURISDICTION										
165	DEMAND		2,001	97	788	335	408	15	3,644		
166	ENERGY		146	8	75	33	38	4	304		
167	TRANSMISSION	1,782	957	47	377	159	186	7	1,733	49	0
168	DISTRIBUTION	7,228	4,245	260	1,471	495	249	481	7,201	27	0
169	DEMAND	5,791	3,387	178	1,391	491	247	71	5,765	26	0
170	CUSTOMER	1,437	858	82	80	4	2	410	1,436	1	0
171	CUSTOMER ACCOUNTS	72	62	5	3	0	0	1	71	1	0
172	CUSTOMER ASSISTANCE	76	34	7	9	25	1	0	76	0	0
173	CUSTOMER	76	34	7	9	25	1	0	76	0	0
174	ENERGY	0	0	0	0	0	0	0	0	0	0
175	TOTAL ACCOUNT 924	13,467	7,445	424	2,723	1,047	882	508	13,029	205	233
176	DEMAND	11,578	6,345	322	2,556	985	841	93	11,142	203	233
177	CUSTOMER	1,585	954	94	92	29	3	411	1,583	2	0
178	ENERGY	304	146	8	75	33	38	4	304	0	0
	REG. COMM. EXP. & UNCOLL.										
179	STATE & FEDERAL	3,171	1,568	108	543	179	155	79	2,632	539	0
180	UNCOLLECTIBLE EXP.	3,809	3,401	256	149	3	0	0	3,809	0	0
181	TOTAL REG. COMM. & UNCOLL.	6,980	4,969	364	692	182	155	79	6,441	539	0
182	OTHER INDUSTRY DUES	705	332	18	173	78	94	10	705	0	0

GULF POWER COMPANY
12 MONTHS ENDING DECEMBER 31, 2014
12/13 DEMAND ALLOCATION
SCHEDULE 4.10 - ANALYSIS OF OPERATIONS AND MAINTENANCE EXPENSE
($000'S)

LINE NO. (1)	DESCRIPTION (2)	TOTAL ELECTRIC SYSTEM (3)	RATE CLASS RESIDENTIAL (4)	RATE CLASS GS (5)	RATE CLASS GSD/GSDT (6)	RATE CLASS LP/LPT (7)	RATE CLASS MAJOR ACCTS (8)	RATE CLASS OS (9)	TOTAL RETAIL SERVICE (10)	WHOLESALE (11)	UNIT POWER SALES (12)
183	MISC. A & G - OTHER REVS.	2	2	0	0	0	0	0	2	0	0
184	MISC. A & G - GULF POWER ENERGY SRVC OH	36	0	0	0	36	0	0	36	0	0
185	MISCELLANEOUS A & G	75,002	44,317	3,529	13,050	4,602	4,669	1,256	71,423	1,195	2,384
186	DEMAND	48,648	25,307	1,264	10,116	4,052	4,106	304	45,149	1,115	2,384
187	CUSTOMER	23,812	17,800	2,198	2,306	271	240	917	23,732	80	0
188	ENERGY	2,542	1,210	87	628	279	323	35	2,542	0	0
189	TOTAL MISCELLANEOUS A & G	75,040	44,319	3,529	13,050	4,638	4,669	1,256	71,461	1,195	2,384
190	DEMAND	48,648	25,307	1,264	10,116	4,052	4,106	304	45,149	1,115	2,384
191	CUSTOMER	23,850	17,802	2,198	2,306	307	240	917	23,770	80	0
192	ENERGY	2,542	1,210	87	628	279	323	35	2,542	0	0
193	TOTAL ADMIN. & GENERAL	96,192	57,065	4,335	16,638	5,945	5,800	1,853	91,636	1,939	2,617
194	TOTAL OPER. & MAINTENANCE	308,608	171,607	12,115	54,278	25,926	20,750	5,523	290,199	5,717	12,692
195	DEMAND	175,348	93,034	4,663	37,239	14,826	14,677	1,156	165,595	3,751	6,002
196	ENERGY	49,974	20,035	1,109	10,405	4,631	5,359	585	42,124	1,160	6,690
197	CUSTOMER	76,308	53,569	5,979	5,942	6,287	559	3,703	76,039	267	0
198	REVENUE	6,980	4,969	364	692	182	155	79	6,441	539	0

GULF POWER COMPANY
12 MONTHS ENDED DECEMBER 31, 2014
12/13 DEMAND ALLOCATION
ANALYSIS OF OPERATIONS AND MAINTENANCE EXPENSE

Line No.	Ftnt Label	Description
1	(A)	Allocated per Level 1 Demand Allocator; UPS directly assigned.
2	(B)	Allocated per Level 1 Energy Allocator; UPS directly assigned.
3	(B)	
5	(A)	
6	(B)	
8	(A)	
9	(B)	
11	(A)	
12	(B)	
14	(C)	Allocated per Level 2 Demand Allocator; UPS directly assigned.
15	(B)	
17	(A)	
18	(A)	
19	(A)	
20	(B)	
22	(A)	
23	(B)	
25	(A)	
26	(B)	
30	(D)	Allocated per Level 1 Demand Allocator.
31	(E)	Allocated per Level 1 Energy Allocator.
32	(E)	
33	(E)	
35	(D)	
36	(E)	
38	(D)	
39	(E)	
42	(D)	
43	(D)	
44	(E)	
46	(D)	
47	(E)	
49	(D)	
50	(E)	
58	(A)	
59	(B)	
60	(B)	

GULF POWER COMPANY
12 MONTHS ENDED DECEMBER 31, 2014
12/13 DEMAND ALLOCATION
ANALYSIS OF OPERATIONS AND MAINTENANCE EXPENSE

Line No.	Ftnt Label	Description
63	(F)	Allocated per sum of Generation Demand Expenses and Purchased Power Demand Expenses.
64	(E)	
66	(D)	
67	(E)	
75	(C)	
76	(G)	Allocated per Transmission Substations Gross Plant; UPS directly assigned.
77	(H)	Allocated per Transmission Lines Gross Plant; UPS directly assigned.
78	(I)	Allocated per Transmission Account 358 Gross Plant.
79	(D)	
81	(J)	Allocated per Subtotal of Transmission Operations O & M Expense; UPS directly assigned.
82	(J)	
83	(J)	
85	(K)	Allocated per sum of Transmission Accounts 352, 354, and 355 Gross Plant; UPS directly assigned.
86	(L)	Allocated per Transmission Account 353 Gross Plant; UPS directly assigned.
87	(H)	
89	(M)	Allocated per Subtotal of Transmission Maintenance O & M Expense; UPS directly assigned.
90	(M)	
93	(N)	Allocated per Level 3 Demand Allocator.
94	(O)	Allocated per Distribution Substations Gross Plant.
95	(P)	Allocated per corresponding Distribution Gross Plant Accounts 365 and 368.
96	(P)	
98	(Q)	Allocated per corresponding Distribution Gross Plant Accounts 367 and 368.
99	(Q)	
101	(R)	Allocated per Distribution Account 373 Gross Plant.
102	(S)	Allocated per Distribution Account 370 Gross Plant.
103	(T)	Per analysis of information provided by Gulf Power Company.
105	(U)	Allocated per Distribution Account 369 Gross Plant.
106	(T)	
111	(V)	Allocated per corresponding Subtotal of Distribution Operations O & M.
112	(V)	
114	(V)	
115	(V)	

GULF POWER COMPANY
12 MONTHS ENDED DECEMBER 31, 2014
12/13 DEMAND ALLOCATION
ANALYSIS OF OPERATIONS AND MAINTENANCE EXPENSE

Line No.	Ftnt Label	Description
117	(V)	
118	(V)	
121	(W)	Allocated per Distribution Account 361 Gross Plant.
122	(X)	Allocated per Distribution Account 362 Gross Plant.
123	(T)	
124	(Y)	Allocated per Common portion of Distribution Accounts 364 and 365.
125	(Z)	Allocated per Customer portion of Distribution Accounts 364 and 365.
128	(AA)	Allocated per Common portion of Distribution Accounts 366 and 367 Gross Plant.
129	(AB)	Allocated per Customer portion of Distribution Accounts 366 and 367 Gross Plant.
131	(AC)	Allocated per Distribution Account 368 Gross Plant.
132	(AC)	
134	(R)	
135	(S)	
139	(AD)	Allocated per corresponding Subtotal of Distribution Maintenance O & M.
140	(AD)	
142	(AD)	
143	(AD)	
149	(AE)	Direct assignment to rate provided by Gulf Power Company.
150	(AF)	Provided by Gulf Power to Class. Allocated to rate based on analysis of average number of customers within class.
151	(AF)	
152	(AF)	
153	(AF)	
154	(AG)	Provided by Gulf Power and assigned to Rate Class LP/LPT.
156	(AF)	
158	(AF)	
159	(AF)	
160	(AF)	
161	(AF)	

GULF POWER COMPANY
12 MONTHS ENDED DECEMBER 31, 2014
12/13 DEMAND ALLOCATION
ANALYSIS OF OPERATIONS AND MAINTENANCE EXPENSE

Line No.	Ftnt Label	Description
164	(AH)	Retail jurisdiction sum of corresponding demand and energy pieces; Wholesale allocated per Level 1 Demand Allocator; UPS directly assigned.
165	(D)	
166	(E)	
167	(AI)	Allocated per Transmission Gross Plant; UPS directly assigned.
168	(AJ)	Allocated per corresponding Distribution Gross Plant.
169	(AJ)	
170	(AJ)	
171	(AK)	Allocated per Customer Accounts O & M Expense.
172	(AL)	Allocated per corresponding Customer Assistance O & M Expense.
173	(AL)	
174	(AL)	
179	(AM)	Provided by Gulf Power to jurisdiction. Allocated to rate per Retail Revenue from Sales.
180	(AE)	
182	(AN)	Allocated per Retail MWH Sales.
183	(T)	
184	(AO)	A&G Overheads related to Gulf Power Energy Services. Assigned to Rate Class LP/LPT.
185	(AP)	Allocated per corresponding Salaries and Wages; UPS directly assigned.
186	(AP)	
187	(AP)	
188	(AP)	

GULF POWER COMPANY
12 MONTHS ENDING DECEMBER 31, 2014
12/13 DEMAND ALLOCATION
SCHEDULE 4.20 - ANALYSIS OF DEPRECIATION EXPENSE
($000'S)

LINE NO. (1)	DESCRIPTION (2)	TOTAL ELECTRIC SYSTEM (3)	RATE CLASS RESIDENTIAL (4)	RATE CLASS GS (5)	RATE CLASS GSD/GSDT (6)	RATE CLASS LP/LPT (7)	RATE CLASS MAJOR ACCTS (6)	RATE CLASS OS (9)	TOTAL RETAIL SERVICE (10)	WHOLESALE (11)	UNIT POWER SALES (12)
1	TOTAL PRODUCTION	52,105	23,360	1,149	9,405	4,018	4,867	213	43,012	1,322	7,771
	RETAIL JURISDICTION										
2	DEMAND		21,785	1,062	8,588	3,654	4,447	167	39,703		
3	ENERGY		1,575	87	817	364	420	46	3,309		
	TRANSMISSION										
4	350-LAND AND LAND RIGHTS	211	114	5	44	19	22	1	205	6	0
5	352-STRUCTURES	197	106	5	42	18	20	1	192	5	0
6	353-STATION EQUIPMENT	3,896	2,065	101	814	334	362	16	3,692	85	119
7	354-TOWERS & FIXTURES	767	408	20	181	68	84	3	744	23	0
8	355-POLES & FIXTURES	5,796	3,085	150	1,216	518	630	24	5,623	173	0
9	356-OVERHEAD COND.	2,138	1,138	55	449	191	232	9	2,074	64	0
10	358-UNDERGROUND COND.	254	134	7	53	23	28	1	246	8	0
11	359-ROADS AND TRAILS	5	3	0	1	0	1	0	5	0	0
12	TOTAL TRANSMISSION	13,264	7,053	343	2,780	1,171	1,379	55	12,781	364	119
	DISTRIBUTION										
13	360-SUBSTATION LAND	13	8	0	3	1	1	0	13	0	0
14	361-STRUCTURES	441	239	12	94	47	39	2	433	8	0
15	362-STATION EQUIPMENT	5,191	2,803	137	1,105	505	536	21	5,107	84	0
	364-POLES & FIXTURES										
16	COMMON	6,281	3,717	201	1,551	531	186	95	6,281	0	0
17	CUSTOMER	0	0	0	0	0	0	0	0	0	0
18	TOTAL ACCOUNT 364	6,281	3,717	201	1,551	531	186	95	6,281	0	0

GULF POWER COMPANY
12 MONTHS ENDING DECEMBER 31, 2014
12/13 DEMAND ALLOCATION
SCHEDULE 4.20 - ANALYSIS OF DEPRECIATION EXPENSE
($000'S)

LINE NO. (1)	DESCRIPTION (2)	TOTAL ELECTRIC SYSTEM (3)	RATE CLASS RESIDENTIAL (4)	RATE CLASS GS (5)	RATE CLASS GSD/GSDT (6)	RATE CLASS LP/LPT (7)	RATE CLASS MAJOR ACCTS (8)	RATE CLASS OS (9)	TOTAL RETAIL SERVICE (10)	WHOLESALE (11)	UNIT POWER SALES (12)
	365-OVERHEAD COND.										
19	DEMAND	4,398	2,601	141	1,086	372	131	67	4,398	0	0
20	CUSTOMER	0	0	0	0	0	0	0	0	0	0
21	TOTAL ACCOUNT 365	4,398	2,601	141	1,086	372	131	67	4,398	0	0
	366-UNDG. CONDUIT										
22	COMMON	14	10	0	3	1	0	0	14	0	0
23	CUSTOMER	0	0	0	0	0	0	0	0	0	0
24	TOTAL ACCOUNT 366	14	10	0	3	1	0	0	14	0	0
	367-UNDERGROUND COND. & DEV.										
25	COMMON	4,533	2,693	146	1,124	377	124	69	4,533	0	0
26	CUSTOMER	0	0	0	0	0	0	0	0	0	0
27	TOTAL ACCOUNT 367	4,533	2,693	146	1,124	377	124	69	4,533	0	0
	368-LINE TRANSFORMERS										
28	COMMON	9,621	5,914	320	2,459	704	72	152	9,621	0	0
29	CUSTOMER	0	0	0	0	0	0	0	0	0	0
30	TOTAL ACCOUNT 368	9,621	5,914	320	2,459	704	72	152	9,621	0	0
31	369-SERVICES	2,838	2,531	191	114	2	0	0	2,838	0	0
32	370-METERS	4,485	3,367	443	604	34	19	10	4,477	8	0
33	373-STREET LIGHTING	2,871	0	0	0	0	0	2,871	2,871	0	0
34	TOTAL DISTRIBUTION	40,686	23,883	1,591	8,143	2,574	1,108	3,287	40,586	100	0
35	DEMAND	30,492	17,985	957	7,425	2,538	1,089	406	30,400	92	0
36	CUSTOMER	10,194	5,898	634	718	36	19	2,881	10,186	8	0
37	GENERAL PLANT	8,347	5,041	402	1,485	524	531	143	8,126	136	85
38	DEMAND	5,349	2,878	144	1,152	461	467	35	5,137	127	85
39	CUSTOMER	2,709	2,025	250	262	31	28	104	2,700	9	0
40	ENERGY	289	138	8	71	32	36	4	289	0	0
41	TOTAL DEPR. EXPENSE	114,402	59,337	3,485	21,813	8,287	7,885	3,698	104,505	1,922	7,975
42	DEMAND	97,901	49,701	2,506	19,945	7,824	7,382	863	88,021	1,905	7,975
43	CUSTOMER	12,903	7,923	884	980	67	47	2,985	12,886	17	0
44	ENERGY	3,598	1,713	95	888	398	456	50	3,598	0	0

GULF POWER COMPANY
12 MONTHS ENDED DECEMBER 31, 2014
12/13 DEMAND ALLOCATION
ANALYSIS OF DEPRECIATION EXPENSE

Line No.	Ftnt Label	Description
1	(A)	Retail jurisdiction sum of Lines 2 and 3; Wholesale allocated per Level 1 Demand Allocator; UPS directly assigned.
2	(B)	Allocated per corresponding Level 1 Demand Allocator.
3	(C)	Allocated per corresponding Level 1 Energy Allocator.
4	(D)	Allocated per Transmission Account 350 Gross Plant (Lines portion only); UPS directly assigned.
5	(E)	Allocated per corresponding Transmission Gross Plant; UPS directly assigned.
6	(E)	
7	(E)	
8	(E)	
9	(E)	
10	(E)	
11	(E)	
13	(F)	Allocated per corresponding Distribution Gross Plant.
14	(F)	
15	(F)	
16	(F)	
17	(F)	
19	(F)	
20	(F)	
22	(F)	
23	(F)	
25	(F)	
26	(F)	
28	(F)	
29	(F)	
31	(F)	
32	(F)	
33	(F)	
37	(G)	Allocated per corresponding Gross General Plant; UPS directly assigned.
38	(G)	
39	(G)	
40	(G)	

GULF POWER COMPANY
12 MONTHS ENDING DECEMBER 31, 2014
12/13 DEMAND ALLOCATION
SCHEDULE 4.30 - ANALYSIS OF TAXES OTHER THAN INCOME TAXES
($000'S)

LINE NO. (1)	DESCRIPTION (2)	TOTAL ELECTRIC SYSTEM (3)	RATE CLASS RESIDENTIAL (4)	RATE CLASS GS (5)	RATE CLASS GSD/GSDT (6)	RATE CLASS LP/LPT (7)	RATE CLASS MAJOR ACCTS (8)	RATE CLASS OS (9)	TOTAL RETAIL SERVICE (10)	WHOLESALE (11)	UNIT POWER SALES (12)
	REAL & PERSONAL PROPERTY										
1	PRODUCTION	17,196	8,587	422	3,456	1,477	1,789	78	15,809	486	901
	RETAIL JURISDICTION										
2	DEMAND		8,009	390	3,156	1,343	1,634	61	14,593		
3	ENERGY		578	32	300	134	155	17	1,216		
4	TRANSMISSION	2,598	1,389	68	547	230	268	11	2,513	71	14
5	DISTRIBUTION	5,968	3,504	215	1,215	409	206	397	5,946	22	0
6	DEMAND	4,779	2,793	147	1,148	406	205	59	4,758	21	0
7	CUSTOMER	1,189	711	68	67	3	1	338	1,188	1	0
8	CUSTOMER ACCOUNTS	120	104	8	5	0	0	2	119	1	0
9	CUSTOMER ASSISTANCE	128	57	12	15	42	2	0	128	0	0
10	CUSTOMER	128	57	12	15	42	2	0	128	0	0
11	ENERGY	0	0	0	0	0	0	0	0	0	0
12	TOTAL ELECTRIC PROP. TAXES	26,010	13,641	725	5,238	2,158	2,265	488	24,515	580	915
13	DEMAND	23,357	12,191	605	4,851	1,979	2,107	131	21,864	578	915
14	CUSTOMER	1,437	872	88	87	45	3	340	1,435	2	0
15	ENERGY	1,216	578	32	300	134	155	17	1,216	0	0
	PAYROLL TAXES										
16	PRODUCTION	3,419	1,698	83	682	291	353	15	3,122	96	201
	RETAIL JURISDICTION										
17	DEMAND		1,582	77	623	265	323	12	2,882		
18	ENERGY		116	6	59	26	30	3	240		
19	TRANSMISSION	299	158	8	62	26	32	1	287	9	3
20	DISTRIBUTION	1,600	994	61	313	99	37	95	1,599	1	0
21	DEMAND	1,178	700	37	290	98	36	16	1,177	1	0
22	CUSTOMER	422	294	24	23	1	1	79	422	0	0
23	CUSTOMER ACCOUNTS	958	834	63	38	1	1	13	950	8	0
24	CUSTOMER ASSISTANCE	1,010	658	134	170	25	23	0	1,010	0	0
25	CUSTOMER	1,010	658	134	170	25	23	0	1,010	0	0
26	ENERGY	0	0	0	0	0	0	0	0	0	0
27	SUBTOTAL ELEC. PAYROLL TAXES	7,286	4,342	349	1,265	442	446	124	6,968	114	204
28	DEMAND	4,656	2,440	122	975	389	391	29	4,346	106	204
29	CUSTOMER	2,390	1,786	221	231	27	25	92	2,382	8	0
30	ENERGY	240	116	6	59	26	30	3	240	0	0
31	ECCR PAYROLL ADJUSTMENT	(369)	(324)	(28)	(17)	0	0	0	(369)	0	0
32	NET ELEC. PAYROLL TAXES	6,917	4,018	321	1,248	442	446	124	6,599	114	204
33	DEMAND	4,656	2,440	122	975	389	391	29	4,346	106	204
34	CUSTOMER	2,390	1,786	221	231	27	25	92	2,382	8	0
35	ENERGY	(129)	(208)	(22)	42	26	30	3	(129)	0	0

GULF POWER COMPANY
12 MONTHS ENDING DECEMBER 31, 2014
12/13 DEMAND ALLOCATION
SCHEDULE 4.30 - ANALYSIS OF TAXES OTHER THAN INCOME TAXES
($000'S)

LINE NO. (1)	DESCRIPTION (2)	TOTAL ELECTRIC SYSTEM (3)	RATE CLASS RESIDENTIAL (4)	RATE CLASS GS (5)	RATE CLASS GSD/GSDT (6)	RATE CLASS LP/LPT (7)	RATE CLASS MAJOR ACCTS (8)	RATE CLASS OS (9)	TOTAL RETAIL SERVICE (10)	WHOLESALE (11)	UNIT POWER SALES (12)
	REVENUE TAXES										
36	GROSS RECEIPTS TAX	0	0	0	0	0	0	0	0	0	0
37	FLA REG. COMM. ASSESSMENT	402	239	17	83	27	24	12	402	0	0
38	FUEL & ECCR REL. REV TAXES	0	0	0	0	0	0	0	0	0	0
39	FRANCHISE FEE REV. ADJ.	0	0	0	0	0	0	0	0	0	0
40	TOTAL REVENUE TAXES	402	239	17	83	27	24	12	402	0	0
	OTHER TAXES										
41	MISS. STATE FRAN. TAX	307	164	8	64	27	34	1	298	9	0
42	FRANCHISE FEE	41,160	24,514	1,696	8,487	2,802	2,431	1,230	41,160	0	0
43	MISCELLANEOUS TAXES	105	64	5	19	7	6	2	103	2	0
44	DEMAND	67	36	2	15	6	6	0	65	2	0
45	CUSTOMER	34	25	3	3	1	0	2	34	0	0
46	ENERGY	4	3	0	1	0	0	0	4	0	0
47	TOTAL OTHER TAXES	41,572	24,742	1,709	8,570	2,836	2,471	1,233	41,561	11	0
48	FRANCHISE FEE ADJUSTMENT	(41,160)	(24,514)	(1,696)	(8,487)	(2,802)	(2,431)	(1,230)	(41,160)	0	0
49	TOTAL TAXES OTHER THAN INC.	33,741	18,126	1,076	6,652	2,661	2,775	627	31,917	705	1,119
50	DEMAND	28,387	14,831	737	5,905	2,401	2,538	161	26,573	695	1,119
51	CUSTOMER	3,861	2,683	312	321	73	28	434	3,851	10	0
52	ENERGY	1,091	373	10	343	160	185	20	1,091	0	0
53	REVENUE RELATED	402	239	17	83	27	24	12	402	0	0

GULF POWER COMPANY
12 MONTHS ENDED DECEMBER 31, 2014
12/13 DEMAND ALLOCATION
ANALYSIS OF TAXES OTHER THAN INCOME TAXES

Line No.	Ftnt Label	Description
1	(A)	Retail jurisdiction sum of Lines 2 and 3; Wholesale allocated per Level 1 Demand Allocator; UPS directly assigned.
2	(B)	Allocated per Level 1 Demand Allocator.
3	(C)	Allocated per Level 1 Energy Allocator.
4	(D)	Allocated per Transmission Gross Plant; UPS directly assigned.
5	(E)	Allocated per corresponding Distribution Gross Plant.
6	(E)	
7	(E)	
8	(F)	Allocated per corresponding Operations and Maintenance Expense.
9	(F)	
10	(F)	
11	(F)	
16	(G)	Allocated per corresponding Salaries and Wages; UPS directly assigned.
17	(H)	Allocated per corresponding Salaries and Wages.
18	(H)	
19	(G)	
20	(H)	
21	(H)	
22	(H)	
23	(H)	
24	(H)	
25	(H)	
26	(H)	
31	(I)	Provided by Gulf Power to Class. Allocated to rate per average number of customers within class.
36	(J)	Allocated per Retail Revenue from Sales.
37	(J)	
38	(K)	Allocated per Retail MWH Sales.
39	(J)	
41	(B)	
42	(J)	
43	(H)	
44	(H)	
45	(H)	
46	(H)	
48	(J)	

GULF POWER COMPANY
12 MONTHS ENDING DECEMBER 31, 2014
12/13 DEMAND ALLOCATION
SCHEDULE 5.0 - LINE ALLOCATORS AND PERCENTAGES

LINE NO. (1)	DESCRIPTION (2)	TOTAL ELECTRIC SYSTEM (3)	RATE CLASS RESIDENTIAL (4)	RATE CLASS GS (5)	RATE CLASS GSD/GSDT (6)	RATE CLASS LP/LPT (7)	RATE CLASS MAJOR ACCTS (8)	RATE CLASS OS (9)	TOTAL RETAIL SERVICE (10)	WHOLESALE (11)	UNIT POWER SALES (12)
1	ENERGY - LEVEL 1	12,219,612	5,643,768	312,270	2,930,180	1,304,356	1,508,184	164,857	11,863,415	356,397	0
2	%	1.0000000	0.4618539	0.0255544	0.2397893	0.1067411	0.1234212	0.0134746	0.9708345	0.0291655	0.0000000
3	MWH SALES	11,505,326	5,264,445	291,283	2,733,687	1,233,654	1,477,619	153,590	11,154,278	351,048	0
4	%	1.0000000	0.4575659	0.0253172	0.2376019	0.1072245	0.1284291	0.0133495	0.9694882	0.0305118	0.0000000
	CP DEMAND										
5	LEVELS 1 & 2	2,149,333	1,144,164	55,758	451,028	191,920	233,603	8,774	2,085,247	64,086	0
6	%	1.0000000	0.5323344	0.0259420	0.2098456	0.0892929	0.1086863	0.0040822	0.9701833	0.0298167	0.0000000
7	LEVEL 3	1,892,428	1,123,290	54,741	442,800	163,856	99,125	8,814	1,892,428	0	0
8	%	1.0000000	0.5935714	0.0289264	0.2339854	0.0865851	0.0523799	0.0045518	1.0000000	0.0000000	0.0000000
	NCP DEMAND										
9	LEVEL 4	2,488,404	1,450,645	78,399	606,448	220,097	93,589	37,246	2,488,404	0	0
10	%	1.0000000	0.5834309	0.0315311	0.2439056	0.0885202	0.0378323	0.0149799	1.0000000	0.0000000	0.0000000
11	LEVEL 5	2,250,357	1,396,380	75,458	580,066	158,305	4,295	35,853	2,250,357	0	0
12	%	1.0000000	0.6205149	0.0335318	0.2577662	0.0703467	0.0019086	0.0159321	1.0000000	0.0000000	0.0000000
	AVERAGE NO. OF CUSTOMERS										
13	LEVEL 4 AND BELOW	443,319	386,033	29,158	17,494	278	48	10,312	443,319	0	0
14	%	1.0000000	0.8707793	0.0657675	0.0394614	0.0006227	0.0001083	0.0232809	1.0000000	0.0000000	0.0000000
15	LEVEL 5	443,246	386,033	29,154	17,486	248	33	10,312	443,246	0	0
16	%	1.0000000	0.8709227	0.0657739	0.0394048	0.0005596	0.0000745	0.0232847	1.0000000	0.0000000	0.0000000
17	TOTAL	443,351	386,033	29,158	17,497	284	68	10,312	443,350	1	0
18	%	1.0000000	0.8707164	0.0657628	0.0394653	0.0006407	0.0001534	0.0232582	0.9999977	0.0000023	0.0000000

GULF POWER COMPANY
12 MONTHS ENDING DECEMBER 31, 2014
12/13 DEMAND ALLOCATION
SCHEDULE 5.0 - LINE ALLOCATORS AND PERCENTAGES

LINE NO. (1)	DESCRIPTION (2)	TOTAL ELECTRIC SYSTEM (3)	RATE CLASS RESIDENTIAL (4)	RATE CLASS GS (5)	RATE CLASS GSD/GSDT (6)	RATE CLASS LP/LPT (7)	RATE CLASS MAJOR ACCTS (8)	RATE CLASS OS (9)	TOTAL RETAIL SERVICE (10)	WHOLESALE (11)	UNIT POWER SALES (12)
	SALARIES AND WAGES										
19	PRODUCTION	37,806	19,921	979	8,020	3,426	4,152	181	36,679	1,127	0
	RETAIL JURISDICTION										
20	12/13 DEMAND RELATED		18,579	905	7,323	3,116	3,793	142	33,858		
21	1/13 ENERGY RELATED		1,342	74	697	310	359	39	2,821		
22	%	1.0000000	0.5269269	0.0258954	0.2121356	0.0906205	0.1098238	0.0047876	0.9701899	0.0298101	0.0000000
23	TRANSMISSION	3,307	1,765	85	695	296	356	13	3,210	97	0
24	%	1.0000000	0.5337164	0.0257031	0.2101603	0.0895071	0.1076504	0.0039311	0.9706683	0.0293317	0.0000000
	DISTRIBUTION										
25	DEMAND	13,045	7,739	413	3,207	1,084	407	182	13,032	13	0
26	CUSTOMER	4,659	3,242	262	261	12	6	873	4,656	3	0
27	TOTAL DISTRIBUTION	17,704	10,981	675	3,468	1,096	413	1,055	17,688	16	0
28	%	1.0000000	0.6202588	0.0381270	0.1958879	0.0619069	0.0233281	0.0595911	0.9990962	0.0009038	0.0000000
29	CUSTOMER ACCOUNTS	10,595	9,219	697	419	11	18	145	10,509	86	0
30	%	1.0000000	0.8701274	0.0657857	0.0395470	0.0010382	0.0016989	0.0136857	0.9918830	0.0081170	0.0000000
	CUSTOMER ASSISTANCE										
31	CUSTOMER	11,170	7,290	1,480	1,879	278	243	0	11,170	0	0
32	ENERGY	0	0	0	0	0	0	0	0	0	0
33	TOTAL CUSTOMER ASST.	11,170	7,290	1,480	1,879	278	243	0	11,170	0	0
34	%	1.0000000	0.6526410	0.1324978	0.1682184	0.0248881	0.0217547	0.0000000	1.0000000	0.0000000	0.0000000
	SUBTOTAL SALARIES & WAGES										
35	DEMAND	51,337	28,083	1,403	11,225	4,496	4,556	337	50,100	1,237	0
36	CUSTOMER	26,424	19,751	2,439	2,559	301	267	1,018	26,335	89	0
37	ENERGY	2,821	1,342	74	697	310	359	39	2,821	0	0
38	SUBTOTAL SALARIES & WAGES	80,582	49,176	3,916	14,481	5,107	5,182	1,394	79,256	1,326	0
39	%	1.0000000	0.6102604	0.0485965	0.1797051	0.0633764	0.0643072	0.0172991	0.9835447	0.0164553	0.0000000
40	ADMINISTRATIVE & GENERAL	16,913	10,321	822	3,039	1,072	1,088	293	16,635	278	0
41	%	1.0000000	0.6102406	0.0486017	0.1796843	0.0633832	0.0643292	0.0173240	0.9835629	0.0164371	0.0000000
42	TOTAL SALARIES & WAGES	97,495	59,497	4,738	17,520	6,179	6,270	1,687	95,891	1,604	0
43	%	1.0000000	0.6102589	0.0485974	0.1797015	0.0633776	0.0643110	0.0173035	0.9835479	0.0164521	0.0000000

GULF POWER COMPANY
12 MONTHS ENDED DECEMBER 31, 2014
12/13 DEMAND ALLOCATION
ANALYSIS OF LINE ALLOCATORS AND PERCENTAGES

Line No.	Ftnt Label	Description
1	(A)	Energy at point of generation.
2	(B)	Percent of above lines total.
3	(C)	Total sales of energy at point of delivery.
4	(B)	
5	(D)	Coincident peak demand at Levels 1 & 2.
6	(B)	
7	(E)	Coincident peak demand at Level 3.
8	(B)	
9	(F)	Non-coincident peak demand at Level 4.
10	(B)	
11	(G)	Non-coincident peak demand at Level 5.
12	(B)	
13	(H)	Average number of customers at Levels 4 & 5.
14	(B)	
15	(I)	Average number of common customers at Level 5.
16	(B)	
17	(J)	Total average number of customers at all levels.
18	(B)	
19	(K)	Retail Jurisdiction sum of lines 2 & 3; Wholesale and Total Retail Service Allocated per Level 1 Demand Allocator.
20	(L)	Allocated per corresponding Level 1 Demand Allocator.
21	(M)	Allocated per corresponding Level 1 Energy Allocator.
22	(B)	
23	(N)	Allocated per Total Transmission O & M Expense excluding UPS.
24	(B)	
25	(O)	Allocated per demand related Distribution O & M Expense.
26	(P)	Allocated per customer related Distribution O & M Expense.
28	(B)	
29	(Q)	Allocated per Customer Accounts Expense excluding UPS.
30	(B)	
31	(R)	Allocated per customer related Customer Assistance Expense excluding UPS and Gulf Power Energy Services.
32	(S)	Allocated per energy related Customer Assistance Expense excluding UPS.
34	(B)	
40	(T)	Allocated per Subtotal Salaries and Wages.
41	(B)	

FILED JUL 12, 2013
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FPSC - COMMISSION CLERK

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 130140-EI

GULF POWER

A SOUTHERN COMPANY

MINIMUM FILING REQUIREMENTS

SECTION E – COST OF SERVICE AND RATE DESIGN SCHEDULES

VOLUME TWO

GULF POWER COMPANY

Docket No. 130140-EI
Minimum Filing Requirements

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Schedule E-2	EXPLANATION OF VARIATIONS FROM COST OF SERVICE STUDY APPROVED IN COMPANY'S LAST RATE CASE	Page 1 of 1
FLORIDA PUBLIC SERVICE COMMISSION COMPANY: GULF POWER COMPANY DOCKET NO.: 130140-EI	EXPLANATION: Explain the differences between the cost of service study approved in the Company's last rate case and that same study filed as part of Schedule E-1 in this rate case (e.g. Classification of plant, allocation factor used for certain plant or expenses, etc.).	Type of Data Shown: X Projected Test Year Ended 12/31/14 ____ Prior Year Ended 12/31/13 ____ Historical Year Ended 12/31/12 Witness: M. T. O'Sheasy

There is not a difference in the cost of service study approved in in the Company's last rate case and the same study filed as part of Schedule E-1 in this rate case.

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

EXPLANATION: For each cost of service study filed, provide the allocation of rate base components as listed below to rate schedules.

Type of Data Shown:
X Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
___ Historical Year Ended 12/31/12

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

($000s)

Witness: M. T. O'Sheasy

Allocation Method: 12MCP - 1/13th kWh - Minimum Distribution System

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
LINE NO.	RATE BASE COMPONENT	TOTAL RETAIL AMOUNT	TOTAL RETAIL PERCENT	RATE CLASS RESIDENTIAL AMOUNT	RATE CLASS RESIDENTIAL PERCENT	RATES CLASS GS AMOUNT	RATES CLASS GS PERCENT	RATES CLASS GSD/GSDT AMOUNT	RATES CLASS GSD/GSDT PERCENT
1	DEMAND								
2	PRODUCTION	588,790	100.00%	323,087	54.88%	15,731	2.67%	127,347	21.63%
3	TRANSMISSION	363,585	100.00%	200,936	55.27%	9,795	2.69%	79,212	21.79%
4	DISTRIBUTION	520,267	100.00%	302,997	58.25%	15,839	3.04%	123,998	23.83%
5	SUBTOTAL	1,472,622	100.00%	827,020	56.15%	41,365	2.81%	330,555	22.45%
6	ENERGY								
7	PRODUCTION PLANT	142,210	100.00%	67,658	47.58%	3,740	2.63%	35,126	24.70%
8	CUSTOMER								
9	METERS	43,264	100.00%	30,821	71.24%	4,973	11.49%	6,775	15.66%
10	SERVICE DROPS	58,524	100.00%	51,961	88.82%	3,926	6.71%	2,352	4.02%
11	CUSTOMER ACCOUNTS	13,795	100.00%	12,100	87.71%	915	6.63%	549	3.98%
12	CUSTOMER SERVICE	14,576	100.00%	9,427	64.68%	1,913	13.12%	2,429	16.67%
13	OTHER RELATED DISTRIBUTION	138,798	100.00%	91,077	65.62%	6,913	4.98%	4,313	3.11%
14	SUBTOTAL	268,957	100.00%	195,408	72.68%	16,640	6.93%	16,416	6.10%
15	TOTAL	1,883,789	100.00%	1,090,084	57.88%	63,745	3.38%	382,099	20.28%
16	REVENUE RELATED	112	100.00%	84	75.00%	7	6.25%	13	11.61%
17	DEMAND								
18	PRODUCTION	588,834	100.00%	323,119	54.88%	15,732	2.67%	127,353	21.63%
19	TRANSMISSION	363,585	100.00%	200,951	55.27%	9,798	2.69%	79,214	21.79%
20	DISTRIBUTION	520,292	100.00%	303,015	58.25%	15,842	3.04%	124,000	23.83%
21	SUBTOTAL	1,472,711	100.00%	827,085	56.15%	41,370	2.81%	330,567	22.45%
22	ENERGY								
23	PRODUCTION PLANT	142,217	100.00%	67,664	47.58%	3,740	2.63%	35,127	24.70%
24	CUSTOMER								
25	METERS	43,267	100.00%	30,823	71.23%	4,974	11.50%	6,775	15.66%
26	SERVICE DROPS	58,528	100.00%	51,985	88.82%	3,926	6.71%	2,352	4.02%
27	CUSTOMER ACCOUNTS	13,795	100.00%	12,100	87.71%	915	6.63%	549	3.98%
28	CUSTOMER SERVICE	14,577	100.00%	9,428	64.69%	1,913	13.12%	2,429	16.66%
29	OTHER RELATED DISTRIBUTION	138,806	100.00%	91,083	65.62%	6,914	4.98%	4,313	3.11%
30	SUBTOTAL	268,973	100.00%	195,419	72.66%	16,642	6.93%	16,416	6.10%
31	TOTAL	1,883,901	100.00%	1,090,188	57.88%	63,752	3.38%	382,112	20.28%

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: For each cost of service study filed, provide the allocation of rate base components as listed below to rate schedules.

($000s)

Type of Data Shown:
X Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
___ Historical Year Ended 12/31/12

Witness: M. T. O'Sheasy

Allocation Method: 12MCP - 1/13th kWh - Minimum Distribution System

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
		RATES CLASS LP/LPT		RATE CLASS MAJOR ACCOUNTS		RATE CLASS OS	
LINE NO.	RATE BASE COMPONENT	AMOUNT	PERCENT	AMOUNT	PERCENT	AMOUNT	PERCENT
1	DEMAND						
2	PRODUCTION	54,192	9.20%	65,959	11.20%	2,474	0.42%
3	TRANSMISSION	33,264	9.15%	38,818	10.68%	1,540	0.42%
4	DISTRIBUTION	45,317	8.71%	26,172	5.03%	5,946	1.14%
5	SUBTOTAL	132,773	9.02%	130,949	8.89%	9,960	0.68%
6	ENERGY						
7	PRODUCTION PLANT	15,633	10.99%	18,080	12.71%	1,973	1.39%
8	CUSTOMER						
9	METERS	382	0.68%	206	0.48%	107	0.25%
10	SERVICE DROPS	34	0.06%	6	0.01%	225	0.38%
11	CUSTOMER ACCOUNTS	14	0.10%	27	0.20%	190	1.38%
12	CUSTOMER SERVICE	496	3.40%	311	2.13%	0	0.00%
13	OTHER RELATED DISTRIBUTION	76	0.05%	14	0.01%	36,405	26.23%
14	SUBTOTAL	1,002	0.37%	564	0.21%	36,927	13.73%
15	TOTAL	149,408	7.93%	149,593	7.94%	48,860	2.59%
16	REVENUE RELATED	4	3.57%	3	2.68%	1	0.89%
17	DEMAND						
18	PRODUCTION	54,195	9.20%	65,961	11.20%	2,474	0.42%
19	TRANSMISSION	33,265	9.15%	38,819	10.68%	1,540	0.42%
20	DISTRIBUTION	45,317	8.71%	26,172	5.03%	5,946	1.14%
21	SUBTOTAL	132,777	9.02%	130,952	8.89%	9,960	0.68%
22	ENERGY						
23	PRODUCTION PLANT	15,633	10.99%	18,080	12.71%	1,973	1.39%
24	CUSTOMER						
25	METERS	382	0.68%	206	0.48%	107	0.25%
26	SERVICE DROPS	34	0.06%	6	0.01%	225	0.38%
27	CUSTOMER ACCOUNTS	14	0.10%	27	0.20%	190	1.38%
28	CUSTOMER SERVICE	496	3.40%	311	2.13%	0	0.00%
29	OTHER RELATED DISTRIBUTION	76	0.05%	14	0.01%	36,406	26.23%
30	SUBTOTAL	1,002	0.37%	564	0.21%	36,928	13.73%
31	TOTAL	149,412	7.93%	149,596	7.94%	48,861	2.59%

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: For each cost of service study filed, provide the allocation of rate base components as listed below to rate schedules.

($000s)

Type of Data Shown:
X Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
___ Historical Year Ended 12/31/12

Witness: M. T. O'Sheasy

Allocation Method: 12MCP - 1/13th kWh

(1) LINE NO.	(2) RATE BASE COMPONENT	(3) TOTAL RETAIL AMOUNT	(4) TOTAL RETAIL PERCENT	(5) RATE CLASS RESIDENTIAL AMOUNT	(6) RATE CLASS RESIDENTIAL PERCENT	(7) RATES CLASS GS AMOUNT	(8) RATES CLASS GS PERCENT	(9) RATES CLASS GSD/GSDT AMOUNT	(10) RATES CLASS GSD/GSDT PERCENT
1	DEMAND								
2	PRODUCTION	588,781	100.00%	323,077	54.88%	15,733	2.67%	127,347	21.63%
3	TRANSMISSION	363,564	100.00%	200,935	55.27%	9,795	2.69%	79,212	21.79%
4	DISTRIBUTION	628,560	100.00%	368,188	58.59%	19,363	3.08%	151,162	24.04%
5	SUBTOTAL	1,580,905	100.00%	892,200	56.43%	44,891	2.84%	357,721	22.63%
6	ENERGY								
7	PRODUCTION PLANT	142,210	100.00%	67,658	47.58%	3,740	2.63%	35,126	24.70%
8	CUSTOMER								
9	METERS	43,264	100.00%	30,821	71.24%	4,973	11.49%	6,775	15.66%
10	SERVICE DROPS	48,841	100.00%	43,550	89.17%	3,289	6.73%	1,970	4.03%
11	CUSTOMER ACCOUNTS	13,799	100.00%	12,098	87.67%	915	6.63%	549	3.98%
12	CUSTOMER SERVICE	14,574	100.00%	9,425	64.67%	1,913	13.13%	2,429	16.67%
13	OTHER RELATED DISTRIBUTION	40,196	100.00%	5,205	12.95%	427	1.06%	423	1.05%
14	SUBTOTAL	160,674	100.00%	101,099	62.91%	11,517	7.17%	12,148	7.56%
15	TOTAL	1,883,789	100.00%	1,060,957	56.33%	60,148	3.19%	404,993	21.50%
16	REVENUE RELATED	112	100.00%	64	75.00%	7	6.25%	13	11.61%
17	DEMAND								
18	PRODUCTION	588,830	100.00%	323,109	54.87%	15,735	2.67%	127,352	21.64%
19	TRANSMISSION	363,587	100.00%	200,953	55.27%	9,796	2.69%	79,214	21.79%
20	DISTRIBUTION	628,593	100.00%	368,212	58.58%	19,368	3.08%	151,167	24.05%
21	SUBTOTAL	1,581,010	100.00%	892,274	56.43%	44,897	2.84%	357,733	22.63%
22	ENERGY								
23	PRODUCTION PLANT	142,217	100.00%	87,664	47.58%	3,740	2.63%	35,127	24.70%
24	CUSTOMER								
25	METERS	43,267	100.00%	30,823	71.23%	4,974	11.50%	6,775	15.66%
26	SERVICE DROPS	48,844	100.00%	43,553	89.17%	3,289	6.73%	1,970	4.03%
27	CUSTOMER ACCOUNTS	13,794	100.00%	12,099	87.71%	915	6.63%	549	3.98%
28	CUSTOMER SERVICE	14,571	100.00%	9,422	64.67%	1,913	13.13%	2,429	16.67%
29	OTHER RELATED DISTRIBUTION	40,197	100.00%	5,205	12.95%	427	1.06%	423	1.05%
30	SUBTOTAL	160,673	100.00%	101,102	62.92%	11,518	7.17%	12,148	7.56%
31	TOTAL	1,883,900	100.00%	1,061,040	56.33%	60,155	3.19%	405,006	21.50%

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: For each cost of service study filed, provide the allocation of rate base components as listed below to rate schedules.

($000s)

Type of Data Shown:
X Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
___ Historical Year Ended 12/31/12

Witness: M. T. O'Sheasy

Allocation Method: 12MCP - 1/13th kWh

(1) LINE NO.	(2) RATE BASE COMPONENT	(3) RATES CLASS LP/LPT AMOUNT	(4) RATES CLASS LP/LPT PERCENT	(5) RATE CLASS MAJOR ACCOUNTS AMOUNT	(6) RATE CLASS MAJOR ACCOUNTS PERCENT	(7) RATE CLASS OS AMOUNT	(8) RATE CLASS OS PERCENT
1	DEMAND						
2	PRODUCTION	54,191	9.20%	65,959	11.20%	2,474	0.42%
3	TRANSMISSION	33,264	9.15%	38,818	10.68%	1,540	0.42%
4	DISTRIBUTION	53,915	6.58%	28,310	4.50%	7,622	1.21%
5	SUBTOTAL	141,370	8.94%	133,087	8.42%	11,636	0.74%
6	ENERGY						
7	PRODUCTION PLANT	15,633	10.99%	18,080	12.71%	1,973	1.39%
8	CUSTOMER						
9	METERS	382	0.68%	206	0.48%	107	0.25%
10	SERVICE DROPS	28	0.06%	4	0.01%	0	0.00%
11	CUSTOMER ACCOUNTS	16	0.12%	30	0.22%	191	1.38%
12	CUSTOMER SERVICE	496	3.40%	311	2.13%	0	0.00%
13	OTHER RELATED DISTRIBUTION	19	0.05%	9	0.02%	34,113	84.87%
14	SUBTOTAL	941	0.59%	560	0.35%	34,411	21.42%
15	TOTAL	157,944	8.38%	151,727	8.05%	48,020	2.55%
16	REVENUE RELATED	4	3.57%	3	2.68%	1	0.89%
17	DEMAND						
18	PRODUCTION	54,195	9.20%	65,964	11.20%	2,475	0.42%
19	TRANSMISSION	33,265	9.15%	38,819	10.68%	1,540	0.42%
20	DISTRIBUTION	53,916	6.58%	28,310	4.50%	7,622	1.21%
21	SUBTOTAL	141,376	8.94%	133,093	8.42%	11,637	0.74%
22	ENERGY						
23	PRODUCTION PLANT	15,633	10.99%	18,080	12.71%	1,973	1.39%
24	CUSTOMER						
25	METERS	382	0.68%	206	0.48%	107	0.25%
26	SERVICE DROPS	28	0.06%	4	0.01%	0	0.00%
27	CUSTOMER ACCOUNTS	14	0.10%	27	0.20%	190	1.38%
28	CUSTOMER SERVICE	496	3.40%	311	2.13%	0	0.00%
29	OTHER RELATED DISTRIBUTION	19	0.05%	9	0.02%	34,114	84.87%
30	SUBTOTAL	939	0.58%	557	0.35%	34,411	21.42%
31	TOTAL	157,948	8.38%	151,730	8.05%	48,021	2.55%

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

EXPLANATION: For each cost of service study filed, provide the allocation of test year expenses to rate schedules.

Type of Data Shown:
X Projected Test Year Ended 12/31/14
Prior Year Ended 12/31/13
Historical Year Ended 12/31/12

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

($000s)

Witness: M. T. O'Sheasy

Allocation Method: 12MCP - 1/13th kWh - Minimum Distribution System

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
LINE NO.	EXPENSE COMPONENT	TOTAL RETAIL AMOUNT	TOTAL RETAIL PERCENT	RATE CLASS RESIDENTIAL AMOUNT	RATE CLASS RESIDENTIAL PERCENT	RATES CLASS GS AMOUNT	RATES CLASS GS PERCENT	RATES CLASS GSD/GSDT AMOUNT	RATES CLASS GSD/GSDT PERCENT
1	DEMAND								
2	PRODUCTION	159,796	100.00%	87,690	54.88%	4,274	2.67%	34,556	21.62%
3	TRANSMISSION	33,760	100.00%	18,592	55.07%	906	2.68%	7,331	21.72%
4	DISTRIBUTION	63,872	100.00%	37,699	59.02%	1,996	3.13%	15,540	24.33%
5	SUBTOTAL	257,430	100.00%	143,981	55.92%	7,178	2.79%	57,427	22.31%
6	ENERGY								
7	PRODUCTION PLANT	46,784	100.00%	22,106	47.25%	1,212	2.59%	11,630	24.86%
8	CUSTOMER								
9	METERS	6,086	100.00%	4,578	75.22%	603	9.91%	821	13.49%
10	SERVICE DROPS	10,189	100.00%	8,960	87.95%	676	6.63%	405	3.97%
11	CUSTOMER ACCOUNTS	33,499	100.00%	29,386	87.73%	2,221	6.63%	1,337	3.99%
12	CUSTOMER SERVICE	30,242	100.00%	16,044	53.05%	3,258	10.77%	4,134	13.67%
13	OTHER RELATED DISTRIBUTION	34,870	100.00%	24,331	70.18%	1,856	5.35%	1,401	4.04%
14	SUBTOTAL	114,686	100.00%	83,299	72.64%	8,614	7.51%	8,098	7.06%
15	TOTAL	418,900	100.00%	249,386	59.53%	17,002	4.06%	77,155	18.42%
16	REVENUE RELATED	8,843	100.00%	5,208	76.10%	381	5.57%	775	11.33%
17	DEMAND								
18	PRODUCTION	162,271	100.00%	89,519	55.17%	4,371	2.69%	34,904	21.51%
19	TRANSMISSION	34,284	100.00%	18,981	55.36%	926	2.70%	7,405	21.60%
20	DISTRIBUTION	64,915	100.00%	38,487	59.29%	2,040	3.14%	15,696	24.18%
21	SUBTOTAL	261,470	100.00%	146,987	56.22%	7,337	2.81%	58,005	22.18%
22	ENERGY								
23	PRODUCTION PLANT	47,462	100.00%	22,568	47.55%	1,239	2.61%	11,747	24.75%
24	CUSTOMER								
25	METERS	6,202	100.00%	4,673	75.35%	616	9.93%	829	13.37%
26	SERVICE DROPS	10,396	100.00%	9,147	87.98%	891	8.65%	409	3.93%
27	CUSTOMER ACCOUNTS	34,179	100.00%	29,999	87.77%	2,271	6.64%	1,350	3.95%
28	CUSTOMER SERVICE	30,732	100.00%	16,379	53.29%	3,331	10.84%	4,175	13.59%
29	OTHER RELATED DISTRIBUTION	35,302	100.00%	24,841	70.36%	1,898	5.38%	1,415	4.01%
30	SUBTOTAL	116,811	100.00%	85,039	72.80%	8,807	7.54%	8,178	7.00%
31	TOTAL	425,743	100.00%	254,594	59.80%	17,383	4.08%	77,930	18.30%

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

EXPLANATION: For each cost of service study filed, provide the allocation of test year expenses to rate schedules.

Type of Data Shown:
X Projected Test Year Ended 12/31/14
Prior Year Ended 12/31/13
Historical Year Ended 12/31/12

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

($000s)

Witness: M. T. O'Sheasy

Allocation Method: 12MCP - 1/13th kWh - Minimum Distribution System

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
LINE NO.	EXPENSE COMPONENT	RATES CLASS LP/LPT AMOUNT	RATES CLASS LP/LPT PERCENT	RATE CLASS MAJOR ACCOUNTS AMOUNT	RATE CLASS MAJOR ACCOUNTS PERCENT	RATE CLASS OS AMOUNT	RATE CLASS OS PERCENT
1	DEMAND						
2	PRODUCTION	14,704	9.20%	17,906	11.21%	668	0.42%
3	TRANSMISSION	3,101	9.19%	3,688	10.92%	142	0.42%
4	DISTRIBUTION	5,391	8.44%	2,420	3.79%	826	1.29%
5	SUBTOTAL	23,196	9.01%	24,014	9.33%	1,636	0.64%
6	ENERGY						
7	PRODUCTION PLANT	5,184	11.08%	5,997	12.82%	655	1.40%
8	CUSTOMER						
9	METERS	46	0.76%	25	0.41%	13	0.21%
10	SERVICE DROPS	7	0.07%	0	0.00%	141	1.38%
11	CUSTOMER ACCOUNTS	34	0.10%	58	0.17%	463	1.38%
12	CUSTOMER SERVICE	6,271	20.74%	535	1.77%	0	0.00%
13	OTHER RELATED DISTRIBUTION	77	0.22%	16	0.05%	6,989	20.16%
14	SUBTOTAL	6,435	5.61%	634	0.55%	7,606	6.63%
15	TOTAL	34,815	8.31%	30,645	7.32%	9,897	2.36%
16	REVENUE RELATED	209	3.05%	179	2.62%	91	1.33%
17	DEMAND						
18	PRODUCTION	14,791	9.11%	18,012	11.10%	674	0.42%
19	TRANSMISSION	3,120	9.10%	3,709	10.82%	143	0.42%
20	DISTRIBUTION	5,424	8.36%	2,434	3.75%	634	1.26%
21	SUBTOTAL	23,335	8.92%	24,155	9.24%	1,651	0.63%
22	ENERGY						
23	PRODUCTION PLANT	5,215	10.99%	6,032	12.71%	661	1.39%
24	CUSTOMER						
25	METERS	46	0.74%	25	0.40%	13	0.21%
26	SERVICE DROPS	7	0.07%	0	0.00%	142	1.37%
27	CUSTOMER ACCOUNTS	34	0.10%	58	0.17%	467	1.37%
28	CUSTOMER SERVICE	6,309	20.53%	538	1.75%	0	0.00%
29	OTHER RELATED DISTRIBUTION	78	0.22%	16	0.05%	7,054	19.98%
30	SUBTOTAL	6,474	5.54%	637	0.55%	7,676	6.57%
31	TOTAL	35,024	8.23%	30,824	7.24%	9,988	2.35%

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: For each cost of service study filed, provide the allocation of test year expenses to rate schedules.

($000s)

Type of Data Shown:
X Projected Test Year Ended 12/31/14
Prior Year Ended 12/31/13
Historical Year Ended 12/31/12

Witness: M. T. O'Sheasy

Allocation Method: 12MCP - 1/13th kWh

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
LINE		TOTAL RETAIL		RATE CLASS RESIDENTIAL		RATES CLASS GS		RATES CLASS GSD/GSDT	
NO.	EXPENSE COMPONENT	AMOUNT	PERCENT	AMOUNT	PERCENT	AMOUNT	PERCENT	AMOUNT	PERCENT
1	DEMAND								
2	PRODUCTION	159,797	100.00%	87,684	54.86%	4,275	2.68%	34,558	21.63%
3	TRANSMISSION	33,760	100.00%	18,593	55.08%	905	2.68%	7,330	21.71%
4	DISTRIBUTION	85,900	100.00%	50,877	59.22%	2,707	3.15%	21,035	24.49%
5	SUBTOTAL	279,457	100.00%	157,154	56.23%	7,887	2.82%	62,923	22.52%
6	ENERGY								
7	PRODUCTION PLANT	48,784	100.00%	22,107	47.25%	1,212	2.59%	11,629	24.66%
8	CUSTOMER								
9	METERS	6,086	100.00%	4,578	75.22%	603	9.91%	821	13.49%
10	SERVICE DROPS	4,144	100.00%	3,695	89.17%	279	6.73%	167	4.03%
11	CUSTOMER ACCOUNTS	33,494	100.00%	29,386	67.74%	2,221	6.63%	1,337	3.99%
12	CUSTOMER SERVICE	30,236	100.00%	16,035	53.03%	3,256	10.77%	4,133	13.67%
13	OTHER RELATED DISTRIBUTION	18,699	100.00%	10,408	55.66%	808	4.32%	775	4.14%
14	SUBTOTAL	92,659	100.00%	64,102	69.16%	7,167	7.73%	7,233	7.81%
15	TOTAL	418,900	100.00%	243,363	58.10%	16,268	3.88%	81,785	19.52%
16	REVENUE RELATED	6,843	100.00%	5,208	76.10%	381	5.57%	775	11.33%
17	DEMAND								
18	PRODUCTION	162,286	100.00%	89,556	55.19%	4,373	2.69%	34,881	21.50%
19	TRANSMISSION	34,289	100.00%	18,991	55.38%	926	2.70%	7,400	21.58%
20	DISTRIBUTION	87,323	100.00%	51,967	59.51%	2,771	3.17%	21,235	24.32%
21	SUBTOTAL	283,900	100.00%	160,514	56.55%	8,070	2.84%	63,516	22.37%
22	ENERGY								
23	PRODUCTION PLANT	47,465	100.00%	22,560	47.58%	1,240	2.61%	11,739	24.73%
24	CUSTOMER								
25	METERS	6,203	100.00%	4,676	75.39%	617	9.95%	829	13.36%
26	SERVICE DROPS	4,232	100.00%	3,774	89.16%	286	6.76%	189	3.99%
27	CUSTOMER ACCOUNTS	34,195	100.00%	30,013	67.76%	2,273	6.65%	1,350	3.95%
28	CUSTOMER SERVICE	30,738	100.00%	16,382	53.29%	3,334	10.85%	4,175	13.58%
29	OTHER RELATED DISTRIBUTION	19,010	100.00%	10,632	55.93%	827	4.35%	782	4.11%
30	SUBTOTAL	94,378	100.00%	65,477	69.38%	7,337	7.77%	7,305	7.74%
31	TOTAL	425,743	100.00%	248,571	58.39%	18,647	3.91%	82,560	19.39%

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: For each cost of service study filed, provide the allocation of test year expenses to rate schedules.

($000s)

Type of Data Shown:
X Projected Test Year Ended 12/31/14
Prior Year Ended 12/31/13
Historical Year Ended 12/31/12

Witness: M. T. O'Sheasy

Allocation Method: 12MCP - 1/13th kWh

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
LINE NO.	EXPENSE COMPONENT	RATES CLASS LP/LPT AMOUNT	PERCENT	RATE CLASS MAJOR ACCOUNTS AMOUNT	PERCENT	RATE CLASS OS AMOUNT	PERCENT
1	DEMAND						
2	PRODUCTION	14,704	9.20%	17,907	11.21%	669	0.42%
3	TRANSMISSION	3,101	9.19%	3,688	10.92%	143	0.42%
4	DISTRIBUTION	7,177	8.36%	2,937	3.42%	1,167	1.36%
5	SUBTOTAL	24,982	8.94%	24,532	8.78%	1,979	0.71%
6	ENERGY						
7	PRODUCTION PLANT	5,184	11.08%	5,997	12.82%	655	1.40%
8	CUSTOMER						
9	METERS	48	0.76%	25	0.41%	13	0.21%
10	SERVICE DROPS	3	0.07%	0	0.00%	0	0.00%
11	CUSTOMER ACCOUNTS	34	0.10%	58	0.17%	458	1.37%
12	CUSTOMER SERVICE	6,277	20.76%	535	1.77%	0	0.00%
13	OTHER RELATED DISTRIBUTION	69	0.37%	18	0.10%	6,621	35.41%
14	SUBTOTAL	6,429	6.94%	636	0.69%	7,092	7.65%
15	TOTAL	36,595	8.74%	31,165	7.44%	9,726	2.32%
16	REVENUE RELATED	209	3.05%	179	2.62%	91	1.33%
17	DEMAND						
18	PRODUCTION	14,791	9.11%	18,016	11.10%	671	0.41%
19	TRANSMISSION	3,119	9.10%	3,709	10.82%	144	0.42%
20	DISTRIBUTION	7,218	8.27%	2,954	3.38%	1,178	1.35%
21	SUBTOTAL	25,128	8.85%	24,679	8.69%	1,993	0.70%
22	ENERGY						
23	PRODUCTION PLANT	5,214	10.98%	6,031	12.71%	661	1.39%
24	CUSTOMER						
25	METERS	48	0.74%	22	0.35%	13	0.21%
26	SERVICE DROPS	3	0.07%	0	0.00%	0	0.00%
27	CUSTOMER ACCOUNTS	34	0.10%	58	0.17%	467	1.37%
28	CUSTOMER SERVICE	6,309	20.53%	538	1.75%	0	0.00%
29	OTHER RELATED DISTRIBUTION	70	0.37%	16	0.08%	6,683	35.16%
30	SUBTOTAL	6,462	6.85%	634	0.67%	7,163	7.59%
31	TOTAL	36,804	8.64%	31,344	7.36%	9,817	2.31%

Supporting Schedules:

Recap Schedules:

Schedule E-4a | COST OF SERVICE STUDY - FUNCTIONALIZATION AND CLASSIFICATION OF RATE BASE | Page 1 of 8

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Functionalize and classify test year rate base by primary account (plant balances, accumulated depreciation and CWIP). The account balances in the B Schedules and those used in the cost of service study must be equal.

(000s)

Type of Data Shown:
X Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
___ Historical Year Ended 12/31/12
Witness: M. T. O'Sheasy

Allocation Method:12MCP - 1/13th kWh - Minimum Distribution Method

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
LINE NO.	RATE BASE ACCOUNT NO. AND TITLE	ADJUSTED JURISDICTIONAL RATE BASE	DEMAND AMOUNT	DEMAND PERCENT	CUSTOMER AMOUNT	CUSTOMER PERCENT	ENERGY AMOUNT	ENERGY PERCENT
1	GROSS PLANT:							
2	PRODUCTION	1,155,365	1,066,491	92.31%	0	0.00%	88,874	7.69%
3	TRANSMISSION							
4	350 - LAND & LAND RIGHTS	19,727	19,727	100.00%	0	0.00%	0	0.00%
5	352 - STRUCTURES	10,706	10,706	100.00%	0	0.00%	0	0.00%
6	353 - STATION EQUIPMENT	154,100	154,100	100.00%	0	0.00%	0	0.00%
7	354 - TOWERS AND FIXTURES	41,528	41,528	100.00%	0	0.00%	0	0.00%
8	355 - POLES AND FIXTURES	144,534	144,534	100.00%	0	0.00%	0	0.00%
9	356 - OVERHEAD CONDUCTORS	82,976	82,976	100.00%	0	0.00%	0	0.00%
10	358 - UNDERGROUND CONDUCTORS	13,675	13,675	100.00%	0	0.00%	0	0.00%
11	359 - ROADS AND TRAILS	229	229	100.00%	0	0.00%	0	0.00%
12	TOTAL TRANSMISSION	467,475	467,475	100.00%	0	0.00%	0	0.00%
13	DISTRIBUTION							
14	360 - STATION LAND	4,607	4,607	100.00%	0	0.00%	0	0.00%
15	361 - STRUCTURES	22,801	22,801	100.00%	0	0.00%	0	0.00%
16	362 - STATION EQUIPMENT	222,354	222,354	100.00%	0	0.00%	0	0.00%
17	364 - POLES AND FIXTURES	133,789	45,622	34.10%	88,167	65.90%	0	0.00%
18	365 - OVERHEAD CONDUCTORS	137,611	115,181	83.70%	22,430	16.30%	0	0.00%
19	366 - UNDERGROUND CONDUIT	1,161	1,114	95.95%	47	4.05%	0	0.00%
20	367 - UNDERGROUND COND. & DEV.	146,818	140,065	95.40%	6,753	4.80%	0	0.00%
21	368 - LINE TRANSFORMERS	253,750	189,297	74.60%	64,453	25.40%	0	0.00%
22	369 - SERVICES	99,675	0	0.00%	99,675	100.00%	0	0.00%
23	370 - METERS	64,981	0	0.00%	64,981	100.00%	0	0.00%
24	373 - STREET LIGHTING	65,351	0	0.00%	65,351	100.00%	0	0.00%
25	TOTAL DISTRIBUTION	1,152,898	741,041	64.28%	411,857	35.72%	0	0.00%
26	GENERAL PLANT	168,430	98,814	58.67%	63,620	37.77%	5,996	3.56%
27	TOTAL GROSS PLANT	2,944,188	2,373,821	80.63%	475,477	16.15%	94,870	3.22%
28	ACCUMULATED DEPRECIATION:							
29	PRODUCTION	615,243	567,917	92.31%	0	0.00%	47,326	7.69%

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Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Functionalize and classify test year rate base by primary account (plant balances, accumulated depreciation and CWIP). The account balances in the B Schedules and those used in the cost of service study must be equal.

(000s)

Type of Data Shown:
X Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
___ Historical Year Ended 12/31/12
Witness: M. T. O'Sheasy

Allocation Method: 12MCP - 1/13th kWh - Minimum Distribution Method

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
LINE NO.	RATE BASE ACCOUNT NO. AND TITLE	ADJUSTED JURISDICTIONAL RATE BASE	DEMAND AMOUNT	DEMAND PERCENT	CUSTOMER AMOUNT	CUSTOMER PERCENT	ENERGY AMOUNT	ENERGY PERCENT
1	TRANSMISSION							
2	350 - EASEMENTS	6,613	6,613	100.00%	0	0.00%	0	0.00%
3	352 - STRUCTURES	3,550	3,550	100.00%	0	0.00%	0	0.00%
4	353 - STATION EQUIPMENT	29,057	29,057	100.00%	0	0.00%	0	0.00%
5	354 - TOWERS AND FIXTURES	24,675	24,675	100.00%	0	0.00%	0	0.00%
6	355 - POLES AND FIXTURES	25,528	25,528	100.00%	0	0.00%	0	0.00%
7	356 - OVERHEAD CONDUCTORS	25,388	25,388	100.00%	0	0.00%	0	0.00%
8	356 - UNDERGROUND CONDUC.	7,429	7,429	100.00%	0	0.00%	0	0.00%
9	359 - ROADS AND TRAILS	39	39	100.00%	0	0.00%	0	0.00%
10	TOTAL TRANSMISSION	122,279	122,279	100.00%	0	0.00%	0	0.00%
11	DISTRIBUTION							
12	360 - EASEMENT	35	35	100.00%	0	0.00%	0	0.00%
13	361 - STRUCTURES	7,717	7,717	100.00%	0	0.00%	0	0.00%
14	362 - STATION EQUIPMENT	60,199	60,199	100.00%	0	0.00%	0	0.00%
15	364 - POLES AND FIXTURES	68,832	23,472	34.10%	45,360	65.90%	0	0.00%
16	365 - OVERHEAD CONDUCTORS	48,656	40,725	83.70%	7,931	16.30%	0	0.00%
17	366 - UNDERGROUND CONDUIT	800	768	96.00%	32	4.00%	0	0.00%
18	367 - UNDERGROUND COND. & DEV.	52,723	50,298	95.40%	2,425	4.60%	0	0.00%
19	368 - LINE TRANSFORMERS	92,899	69,302	74.60%	23,597	25.40%	0	0.00%
20	369 - SERVICES	50,834	0	0.00%	50,834	100.00%	0	0.00%
21	370 - METERS	21,717	0	0.00%	21,717	100.00%	0	0.00%
22	373 - STREET LIGHTING	33,445	0	0.00%	33,445	100.00%	0	0.00%
23	TOTAL DISTRIBUTION	437,857	252,516	57.67%	185,341	42.33%	0	0.00%
24	GENERAL PLANT	67,940	39,859	58.67%	25,663	37.77%	2,418	3.58%
25	TOTAL ACCUM. DEPRECIATION	1,243,319	982,571	79.03%	211,004	16.97%	49,744	4.00%

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Functionalize and classify test year rate base by primary account (plant balances, accumulated depreciation and CWIP). The account balances in the B Schedules and those used in the cost of service study must be equal.

(000s)

Type of Data Shown:
X Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
___ Historical Year Ended 12/31/12
Witness: M. T. O'Sheasy

Allocation Method:12MCP - 1/13th kWh - Minimum Distribution Method

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
LINE NO.	RATE BASE ACCOUNT NO. AND TITLE	ADJUSTED JURISDICTIONAL RATE BASE	DEMAND AMOUNT	DEMAND PERCENT	CUSTOMER AMOUNT	CUSTOMER PERCENT	ENERGY AMOUNT	ENERGY PERCENT
1	MATERIALS & SUPPLIES:							
2	PRODUCTION	120,408	25,092	20.84%	0	0.00%	95,316	79.16%
3	TRANSMISSION	4,070	4,070	100.00%	0	0.00%	0	0.00%
4	DISTRIBUTION	16,523	15,722	95.15%	801	4.85%	0	0.00%
5	CUSTOMER ACCOUNTS	5	0	0.00%	5	100.00%	0	0.00%
6	CUSTOMER ASSISTANCE	5	0	0.00%	5	100.00%	0	0.00%
7	TOTAL MATERIALS & SUPPLIES	141,011	44,884	31.83%	811	0.58%	95,316	67.59%
8	WORK NOT BEARING INTEREST:							
9	PRODUCTION	10,447	9,643	92.30%	0	0.00%	804	7.70%
10	TRANSMISSION	10,412	10,412	100.00%	0	0.00%	0	0.00%
11	DISTRIBUTION	5,797	3,726	64.27%	2,071	35.73%	0	0.00%
12	CUSTOMER ACCOUNTS	0	0	0.00%	0	100.00%	0	0.00%
13	CUSTOMER ASSISTANCE	0	0	0.00%	0	100.00%	0	0.00%
14	TOTAL WORK NOT BEARING INT.	26,656	23,781	89.21%	2,071	7.77%	804	3.02%
15	OTHER WORKING CAPITAL:							
16	PRODUCTION	9,815	9,136	93.08%	0	0.00%	679	6.92%
17	TRANSMISSION	(58)	(58)	100.00%	0	0.00%	0	0.00%
18	DISTRIBUTION	1,737	688	39.61%	1,049	60.39%	0	0.00%
19	CUSTOMER ACCOUNTS	872	0	0.00%	872	100.00%	0	0.00%
20	CUSTOMER ASSISTANCE	838	0	0.00%	838	100.00%	0	0.00%
21	REVENUE RELATED INVESTMENT	107	87	81.31%	11	10.28%	9	8.41%
22	TOTAL OTHER WORKING CAPITAL	13,311	9,853	74.02%	2,770	20.81%	688	5.17%

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Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Functionalize and classify test year rate base by primary account (plant balances, accumulated depreciation and CWIP). The account balances in the B Schedules and those used in the cost of service study must be equal.

(000s)

Type of Data Shown:
X Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
___ Historical Year Ended 12/31/12

Witness: M. T. O'Sheasy

Allocation Method:12MCP - 1/13th kWh - Minimum Distribution Method

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
LINE NO.	RATE BASE ACCOUNT NO. AND TITLE	ADJUSTED JURISDICTIONAL RATE BASE	DEMAND AMOUNT	DEMAND PERCENT	CUSTOMER AMOUNT	CUSTOMER PERCENT	ENERGY AMOUNT	ENERGY PERCENT
1	OTHER RATE BASE ITEMS:							
2	PRODUCTION	3,701	3,418	92.35%	0	0.00%	283	7.65%
3	TRANSMISSION	(125)	(125)	100.00%	0	0.00%	0	0.00%
4	DISTRIBUTION	(663)	(350)	52.79%	(313)	47.21%	0	0.00%
5	CUSTOMER ACCOUNTS	(408)	0	0.00%	(408)	100.00%	0	0.00%
6	CUSTOMER ASSISTANCE	(431)	0	0.00%	(431)	100.00%	0	0.00%
7	TOTAL OTHER RATE BASE ITEMS	2,074	2,943	141.90%	(1,152)	-55.55%	283	13.65%
8	TOTAL RATE BASE	1,883,901	1,472,711	78.17%	268,973	14.28%	142,217	7.55%

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Functionalize and classify test year rate base by primary account (plant balances, accumulated depreciation and CWIP). The account balances in the B Schedules and those used in the cost of service study must be equal.

(000s)

Type of Data Shown:
X Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
___ Historical Year Ended 12/31/12

Witness: M. T. O'Sheasy

Allocation Method: 12MCP - 1/13th kWh

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
LINE NO.	RATE BASE ACCOUNT NO. AND TITLE	ADJUSTED JURISDICTIONAL RATE BASE	DEMAND AMOUNT	DEMAND PERCENT	CUSTOMER AMOUNT	CUSTOMER PERCENT	ENERGY AMOUNT	ENERGY PERCENT
1	GROSS PLANT:							
2	PRODUCTION	1,155,365	1,066,491	92.31%	0	0.00%	88,874	7.69%
3	TRANSMISSION							
4	350 - LAND & LAND RIGHTS	19,727	19,727	100.00%	0	0.00%	0	0.00%
5	352 - STRUCTURES	10,706	10,706	100.00%	0	0.00%	0	0.00%
6	353 - STATION EQUIPMENT	154,100	154,100	100.00%	0	0.00%	0	0.00%
7	354 - TOWERS AND FIXTURES	41,528	41,528	100.00%	0	0.00%	0	0.00%
8	355 - POLES AND FIXTURES	144,534	144,534	100.00%	0	0.00%	0	0.00%
9	356 - OVERHEAD CONDUCTORS	82,976	82,976	100.00%	0	0.00%	0	0.00%
10	358 - UNDERGROUND CONDUCTORS	13,675	13,675	100.00%	0	0.00%	0	0.00%
11	359 - ROADS AND TRAILS	229	229	100.00%	0	0.00%	0	0.00%
12	TOTAL TRANSMISSION	467,475	467,475	100.00%	0	0.00%	0	0.00%
13	DISTRIBUTION							
14	360 - STATION LAND	4,607	4,607	100.00%	0	0.00%	0	0.00%
15	361 - STRUCTURES	22,801	22,801	100.00%	0	0.00%	0	0.00%
16	362 - STATION EQUIPMENT	222,354	222,354	100.00%	0	0.00%	0	0.00%
17	364 - POLES AND FIXTURES	133,789	133,789	100.00%	0	0.00%	0	0.00%
18	365 - OVERHEAD CONDUCTORS	137,611	137,611	100.00%	0	0.00%	0	0.00%
19	366 - UNDERGROUND CONDUIT	1,161	1,161	100.00%	0	0.00%	0	0.00%
20	367 - UNDERGROUND COND. & DEV.	146,818	146,818	100.00%	0	0.00%	0	0.00%
21	368 - LINE TRANSFORMERS	253,750	253,750	100.00%	0	0.00%	0	0.00%
22	369 - SERVICES	99,675	0	0.00%	99,675	100.00%	0	0.00%
23	370 - METERS	64,981	0	0.00%	64,981	100.00%	0	0.00%
24	373 - STREET LIGHTING	65,351	0	0.00%	65,351	100.00%	0	0.00%
25	TOTAL DISTRIBUTION	1,152,898	922,891	80.05%	230,007	19.95%	0	0.00%
26	GENERAL PLANT	168,430	106,468	63.21%	55,966	33.23%	5,996	3.56%
27	TOTAL GROSS PLANT	2,944,168	2,563,325	87.07%	285,973	9.71%	94,870	3.22%
28	ACCUMULATED DEPRECIATION:							
29	PRODUCTION	615,243	567,917	92.31%	0	0.00%	47,326	7.69%

Supporting Schedules:

Recap Schedules:

Schedule E-4a | COST OF SERVICE STUDY - FUNCTIONALIZATION AND CLASSIFICATION OF RATE BASE | Page 6 of 8

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Functionalize and classify test year rate base by primary account (plant balances, accumulated depreciation and CWIP). The account balances in the B Schedules and those used in the cost of service study must be equal.

(000s)

Type of Data Shown:
X Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
___ Historical Year Ended 12/31/12

Witness: M. T. O'Sheasy

Allocation Method: 12MCP - 1/13th kWh

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
LINE NO.	RATE BASE ACCOUNT NO. AND TITLE	ADJUSTED JURISDICTIONAL RATE BASE	DEMAND AMOUNT	DEMAND PERCENT	CUSTOMER AMOUNT	CUSTOMER PERCENT	ENERGY AMOUNT	ENERGY PERCENT
1	TRANSMISSION							
2	350 - EASEMENTS	6,613	6,613	100.00%	0	0.00%	0	0.00%
3	352 - STRUCTURES	3,550	3,550	100.00%	0	0.00%	0	0.00%
4	353 - STATION EQUIPMENT	29,057	29,057	100.00%	0	0.00%	0	0.00%
5	354 - TOWERS AND FIXTURES	24,675	24,675	100.00%	0	0.00%	0	0.00%
6	355 - POLES AND FIXTURES	25,528	25,528	100.00%	0	0.00%	0	0.00%
7	356 - OVERHEAD CONDUCTORS	25,388	25,388	100.00%	0	0.00%	0	0.00%
8	358 - UNDERGROUND CONDUC.	7,429	7,429	100.00%	0	0.00%	0	0.00%
9	359 - ROADS AND TRAILS	39	39	100.00%	0	0.00%	0	0.00%
10	TOTAL TRANSMISSION	122,279	122,279	100.00%	0	0.00%	0	0.00%
11	DISTRIBUTION							
12	360 - EASEMENT	35	35	100.00%	0	0.00%	0	0.00%
13	361 - STRUCTURES	7,717	7,717	100.00%	0	0.00%	0	0.00%
14	362 - STATION EQUIPMENT	60,199	60,199	100.00%	0	0.00%	0	0.00%
15	364 - POLES AND FIXTURES	68,832	68,832	100.00%	0	0.00%	0	0.00%
16	365 - OVERHEAD CONDUCTORS	48,656	48,656	100.00%	0	0.00%	0	0.00%
17	366 - UNDERGROUND CONDUIT	800	800	100.00%	0	0.00%	0	0.00%
18	367 - UNDERGROUND COND. & DEV.	52,723	52,723	100.00%	0	0.00%	0	0.00%
19	368 - LINE TRANSFORMERS	92,899	92,899	100.00%	0	0.00%	0	0.00%
20	369 - SERVICES	50,834	0	0.00%	50,834	100.00%	0	0.00%
21	370 - METERS	21,717	0	0.00%	21,717	100.00%	0	0.00%
22	373 - STREET LIGHTING	33,445	0	0.00%	33,445	100.00%	0	0.00%
23	TOTAL DISTRIBUTION	437,857	331,861	75.79%	105,996	24.21%	0	0.00%
24	GENERAL PLANT	67,940	42,947	63.21%	22,575	33.23%	2,418	3.56%
25	TOTAL ACCUM. DEPRECIATION	1,243,319	1,065,004	85.66%	128,571	10.34%	49,744	4.00%

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Functionalize and classify test year rate base by primary account (plant balances, accumulated depreciation and CWIP). The account balances in the B Schedules and those used in the cost of service study must be equal.

(000s)

Type of Data Shown:
X Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
___ Historical Year Ended 12/31/12
Witness: M. T. O'Sheasy

Allocation Method: 12MCP - 1/13th kWh

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
LINE NO.	RATE BASE ACCOUNT NO. AND TITLE	ADJUSTED JURISDICTIONAL RATE BASE	DEMAND AMOUNT	DEMAND PERCENT	CUSTOMER AMOUNT	CUSTOMER PERCENT	ENERGY AMOUNT	ENERGY PERCENT
1	MATERIALS & SUPPLIES:							
2	PRODUCTION	120,408	25,092	20.84%	0	0.00%	95,316	79.16%
3	TRANSMISSION	4,070	4,070	100.00%	0	0.00%	0	0.00%
4	DISTRIBUTION	16,523	15,722	95.15%	801	4.85%	0	0.00%
5	CUSTOMER ACCOUNTS	5	0	0.00%	5	100.00%	0	0.00%
6	CUSTOMER ASSISTANCE	5	0	0.00%	5	100.00%	0	0.00%
7	TOTAL MATERIALS & SUPPLIES	141,011	44,884	31.83%	811	0.58%	95,316	67.59%
8	WORK NOT BEARING INTEREST:							
9	PRODUCTION	10,447	9,643	92.30%	0	0.00%	804	7.70%
10	TRANSMISSION	10,412	10,412	100.00%	0	0.00%	0	0.00%
11	DISTRIBUTION	5,797	4,640	80.04%	1,157	19.96%	0	0.00%
12	CUSTOMER ACCOUNTS	0	0	0.00%	0	100.00%	0	0.00%
13	CUSTOMER ASSISTANCE	0	0	0.00%	0	100.00%	0	0.00%
14	TOTAL WORK NOT BEARING INT.	26,656	24,695	92.64%	1,157	4.34%	804	3.02%
15	OTHER WORKING CAPITAL:							
16	PRODUCTION	9,816	9,135	93.06%	0	0.00%	681	6.94%
17	TRANSMISSION	(58)	(58)	100.00%	0	0.00%	0	0.00%
18	DISTRIBUTION	1,740	1,128	64.83%	612	35.17%	0	0.00%
19	CUSTOMER ACCOUNTS	866	0	0.00%	866	100.00%	0	0.00%
20	CUSTOMER ASSISTANCE	838	0	0.00%	838	100.00%	0	0.00%
21	REVENUE RELATED INVESTMENT	109	93	85.32%	7	6.42%	9	8.26%
22	TOTAL OTHER WORKING CAPITAL	13,311	10,298	77.37%	2,323	17.45%	690	5.18%

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Functionalize and classify test year rate base by primary account (plant balances, accumulated depreciation and CWIP). The account balances in the B Schedules and those used in the cost of service study must be equal.

(000s)

Type of Data Shown:
X Projected Test Year Ended 12/31/14
__ Prior Year Ended 12/31/13
__ Historical Year Ended 12/31/12

Witness: M. T. O'Sheasy

Allocation Method: 12MCP - 1/13th kWh

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(6)	(9)
LINE NO.	RATE BASE ACCOUNT NO. AND TITLE	ADJUSTED JURISDICTIONAL RATE BASE	DEMAND AMOUNT	DEMAND PERCENT	CUSTOMER AMOUNT	CUSTOMER PERCENT	ENERGY AMOUNT	ENERGY PERCENT
1	OTHER RATE BASE ITEMS:							
2	PRODUCTION	3,702	3,418	92.33%	0	0.00%	284	7.67%
3	TRANSMISSION	(125)	(125)	100.00%	0	0.00%	0	0.00%
4	DISTRIBUTION	(666)	(487)	73.12%	(179)	26.88%	0	0.00%
5	CUSTOMER ACCOUNTS	(407)	0	0.00%	(407)	100.00%	0	0.00%
6	CUSTOMER ASSISTANCE	(430)	0	0.00%	(430)	100.00%	0	0.00%
7	TOTAL OTHER RATE BASE ITEMS	2,074	2,806	135.29%	(1,016)	-48.99%	284	13.69%
8	TOTAL RATE BASE	1,883,901	1,581,004	83.92%	160,677	8.53%	142,220	7.55%

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Functionalize and classify test year operating expenses by primary account (depreciation expense, operation and maintenance expense and any other expense items). The balances in the C Schedules and those used in the cost of service study must be equal.

(000s)

Type of Data Shown:
X Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
___ Historical Year Ended 12/31/12

Witness: M. T. O'Sheasy

Allocation Method: 12MCP - 1/13th kWh - Minimum Distribution Method

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
LINE NO.	OPERATING EXPENSE ACCOUNT NO. AND TITLE	ADJUSTED JURISDICTIONAL OPERATING EXPENSES	DEMAND AMOUNT	DEMAND PERCENT	CUSTOMER AMOUNT	CUSTOMER PERCENT	ENERGY AMOUNT	ENERGY PERCENT
1	OPERATING & MAINTENANCE:							
2	PRODUCTION	103,580	65,007	62.76%	0	0.00%	38,573	37.24%
3	TRANSMISSION							
4	560 - SUPERVISION	1,560	1,560	100.00%	0	0.00%	0	0.00%
5	561 - LOAD DISPATCH	3,419	3,419	100.00%	0	0.00%	0	0.00%
6	562 - STATION	42	42	100.00%	0	0.00%	0	0.00%
7	563 - OVERHEAD LINES	185	185	100.00%	0	0.00%	0	0.00%
8	564 - UNDERGROUND LINES	0	0	0.00%	0	0.00%	0	0.00%
9	565 - TRANS. OF ELEC.	(292)	(292)	100.00%	0	0.00%	0	0.00%
10	568 - MISCELLANEOUS	1,006	1,006	100.00%	0	0.00%	0	0.00%
11	567 - RENTS	160	160	100.00%	0	0.00%	0	0.00%
12	568 - SUPERVISION	1,021	1,021	100.00%	0	0.00%	0	0.00%
13	569 - STRUCTURES	973	973	100.00%	0	0.00%	0	0.00%
14	570 - STATION EQUIPMENT	811	811	100.00%	0	0.00%	0	0.00%
15	571 - OVERHEAD LINES	4,345	4,345	100.00%	0	0.00%	0	0.00%
16	573 - MISCELLANEOUS	99	99	100.00%	0	0.00%	0	0.00%
17	TOTAL TRANSMISSION	13,329	13,329	100.00%	0	0.00%	0	0.00%
18	DISTRIBUTION							
19	580 - SUPERVISION	6,762	2,843	42.04%	3,919	57.96%	0	0.00%
20	581 - LOAD DISPATCH	902	902	100.00%	0	0.00%	0	0.00%
21	582 - STATION	303	303	100.00%	0	0.00%	0	0.00%
22	583 - OVERHEAD LINES	2,579	2,007	77.82%	572	22.18%	0	0.00%
23	584 - UNDERGROUND LINES	739	607	82.14%	132	17.86%	0	0.00%
24	585 - STREET LIGHTING	598	0	0.00%	598	100.00%	0	0.00%
25	586 - METER	2,624	0	0.00%	2,624	100.00%	0	0.00%
26	587 - CUSTOMER INSTA.	1,331	0	0.00%	1,331	100.00%	0	0.00%
27	588 - MISCELLANEOUS	4,360	1,834	42.06%	2,526	57.94%	0	0.00%
28	589 - RENTS	0	0	0.00%	0	0.00%	0	0.00%
29	590 - SUPERVISION	3,660	2,332	63.72%	1,328	36.28%	0	0.00%
30	591 - STRUCTURES	27	27	100.00%	0	0.00%	0	0.00%
31	592 - STATION	946	946	100.00%	0	0.00%	0	0.00%
32	593 - OVERHEAD	13,075	7,749	59.27%	5,326	40.73%	0	0.00%
33	594 - UNDERGROUND	1,897	1,810	95.41%	87	4.59%	0	0.00%
34	595 - LINE TRANS.	1,001	747	74.63%	254	25.37%	0	0.00%
35	596 - STREET LIGHTING	597	0	0.00%	597	100.00%	0	0.00%
36	597 - METERS	159	0	0.00%	159	100.00%	0	0.00%
37	598 - MISCELLANEOUS	472	301	63.77%	171	36.23%	0	0.00%
38	TOTAL DISTRIBUTION	42,032	22,408	53.31%	19,624	46.69%	0	0.00%

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Functionalize and classify test year operating expenses by primary account (depreciation expense, operation and maintenance expense and any other expense items). The balances in the C Schedules and those used in the cost of service study must be equal.

(000s)

Type of Data Shown:
X Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
___ Historical Year Ended 12/31/12
Witness: M. T. O'Sheasy

Allocation Method:12MCP - 1/13th kWh - Minimum Distribution Method

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
LINE NO.	OPERATING EXPENSE ACCOUNT NO. AND TITLE	ADJUSTED JURISDICTIONAL OPERATING EXPENSES	DEMAND AMOUNT	DEMAND PERCENT	CUSTOMER AMOUNT	CUSTOMER PERCENT	ENERGY AMOUNT	ENERGY PERCENT
1	CUSTOMER ACCOUNTS	21,807	0	0.00%	21,807	100.00%	0	0.00%
2	CUSTOMER ASSISTANCE	17,815	0	0.00%	17,815	100.00%	0	0.00%
3	ADMINISTRATION & GENERAL:							
4	PRODUCTION	37,711	34,160	90.58%	0	0.00%	3,551	9.42%
5	TRANSMISSION	4,627	4,627	100.00%	0	0.00%	0	0.00%
6	DISTRIBUTION	23,178	13,121	56.61%	10,057	43.39%	0	0.00%
7	CUSTOMER ACCOUNTS	9,541	0	0.00%	9,541	100.00%	0	0.00%
8	CUSTOMER ASSISTANCE	10,136	0	0.00%	10,136	100.00%	0	0.00%
9	TOTAL ADMIN. & GENERAL	85,195	51,908	60.93%	29,736	34.90%	3,551	4.17%
10	TOTAL OPERATION & MAINT.	283,758	152,652	53.80%	88,982	31.36%	42,124	14.84%
11	DEPRECIATION EXPENSE							
12	PRODUCTION	43,012	39,703	92.31%	0	0.00%	3,309	7.69%
13	TRANSMISSION							
14	350 - EASEMENTS	205	205	100.00%	0	0.00%	0	0.00%
15	352 - STRUCTURES	192	192	100.00%	0	0.00%	0	0.00%
16	353 - STATION EQUIP.	3,692	3,692	100.00%	0	0.00%	0	0.00%
17	354 - TOWERS	744	744	100.00%	0	0.00%	0	0.00%
18	355 - POLES	5,623	5,623	100.00%	0	0.00%	0	0.00%
19	356 - OVERHEAD	2,074	2,074	100.00%	0	0.00%	0	0.00%
20	358 - UNDERGROUND	246	246	100.00%	0	0.00%	0	0.00%
21	359 - ROAD & TRAILS	5	5	100.00%	0	0.00%	0	0.00%
22	TOTAL TRANSMISSION	12,781	12,781	100.00%	0	0.00%	0	0.00%
23	DISTRIBUTION							
24	360 - EASEMENTS	13	13	100.00%	0	0.00%	0	0.00%
25	361 - STRUCTURES	433	433	100.00%	0	0.00%	0	0.00%
26	362 - STATION EQUIP.	5,107	5,107	100.00%	0	0.00%	0	0.00%
27	364 - POLES & FIXTURES	6,281	2,142	34.10%	4,139	65.90%	0	0.00%
28	365 - OVERHEAD COND.	4,398	3,681	83.70%	717	16.30%	0	0.00%
29	366 - UNDERGROUND CONDUIT	14	13	92.86%	1	7.14%	0	0.00%
30	367 - UNDERGROUND COND.	4,533	4,325	95.41%	208	4.59%	0	0.00%

Supporting Schedules: Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Functionalize and classify test year operating expenses by primary account (depreciation expense, operation and maintenance expense and any other expense items). The balances in the C Schedules and those used in the cost of service study must be equal.

(000s)

Type of Data Shown:
X Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
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Witness: M. T. O'Sheasy

Allocation Method: 12MCP - 1/13th kWh - Minimum Distribution Method

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
LINE NO.	OPERATING EXPENSE ACCOUNT NO. AND TITLE	ADJUSTED JURISDICTIONAL OPERATING EXPENSES	DEMAND AMOUNT	DEMAND PERCENT	CUSTOMER AMOUNT	CUSTOMER PERCENT	ENERGY AMOUNT	ENERGY PERCENT
1	368 - LINE TRANSFORMERS	9,621	7,177	74.60%	2,444	25.40%	0	0.00%
2	369 - SERVICES	2,838	0	0.00%	2,838	100.00%	0	0.00%
3	370 - METERS	4,477	0	0.00%	4,477	100.00%	0	0.00%
4	373 - STREET LIGHTING	2,871	0	0.00%	2,871	100.00%	0	0.00%
5	TOTAL DISTRIBUTION	40,586	22,891	56.40%	17,695	43.60%	0	0.00%
6	GENERAL:							
7	PRODUCTION	3,759	3,470	92.31%	0	0.00%	289	7.69%
8	TRANSMISSION	330	330	100.00%	0	0.00%	0	0.00%
9	DISTRIBUTION	1,814	967	53.31%	847	46.69%	0	0.00%
10	CUSTOMER ACCOUNTS	1,077	0	0.00%	1,077	100.00%	0	0.00%
11	CUSTOMER ASSISTANCE	1,146	0	0.00%	1,146	100.00%	0	0.00%
12	TOTAL GENERAL	8,126	4,767	58.66%	3,070	37.78%	289	3.56%
13	TOTAL DEPRECIATION EXP.	104,505	80,142	76.69%	20,765	19.87%	3,598	3.44%
14	REAL & PERS. PROP. TXS.:							
15	PRODUCTION	15,809	14,593	92.31%	0	0.00%	1,216	7.69%
16	TRANSMISSION	2,513	2,513	100.00%	0	0.00%	0	0.00%
17	DISTRIBUTION	5,946	3,823	64.30%	2,123	35.70%	0	0.00%
18	CUSTOMER ACCOUNTS	119	0	0.00%	119	100.00%	0	0.00%
19	CUSTOMER ASSISTANCE	128	0	0.00%	128	100.00%	0	0.00%
20	TOTAL REAL & PERS. PROP TXS	24,515	20,929	85.37%	2,370	9.67%	1,216	4.96%
21	PAYROLL TAXES:							
22	PRODUCTION	2,753	2,882	104.69%	0	0.00%	(129)	-4.69%
23	TRANSMISSION	287	287	100.00%	0	0.00%	0	0.00%
24	DISTRIBUTION	1,598	853	53.38%	745	46.62%	0	0.00%
25	CUSTOMER ACCOUNTS	950	0	0.00%	950	100.00%	0	0.00%
26	CUSTOMER ASSISTANCE	1,011	0	0.00%	1,011	100.00%	0	0.00%
27	TOTAL PAYROLL TAXES	6,599	4,022	60.95%	2,706	41.01%	(129)	-1.96%

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Functionalize and classify test year operating expenses by primary account (depreciation expense, operation and maintenance expense and any other expense items). The balances in the C Schedules and those used in the cost of service study must be equal.

(000s)

Type of Data Shown:
X Projected Test Year Ended 12/31/14
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Witness: M. T. O'Sheasy

Allocation Method:12MCP - 1/13th kWh - Minimum Distribution Method

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
LINE NO.	OPERATING EXPENSE ACCOUNT NO. AND TITLE	ADJUSTED JURISDICTIONAL OPERATING EXPENSES	DEMAND AMOUNT	DEMAND PERCENT	CUSTOMER AMOUNT	CUSTOMER PERCENT	ENERGY AMOUNT	ENERGY PERCENT
1	MISS. FRANCHISE TAXES	298	298	100.00%	0	0.00%	0	0.00%
2	MISCELLANEOUS TAXES:							
3	PRODUCTION	48	44	91.67%	0	0.00%	4	8.33%
4	TRANSMISSION	4	4	100.00%	0	0.00%	0	0.00%
5	DISTRIBUTION	23	12	52.17%	11	47.83%	0	0.00%
6	CUSTOMER ACCOUNTS	14	0	0.00%	14	100.00%	0	0.00%
7	CUSTOMER ASSISTANCE	14	0	0.00%	14	100.00%	0	0.00%
8	TOTAL MISCELLANEOUS TAXES	103	60	58.25%	39	37.87%	4	3.88%
9	TOTAL TAXES OTHER THAN							
10	INCOME TAXES	31,515	25,309	80.31%	5,115	16.23%	1,091	3.46%
11	TOTAL EXPENSES EXCL. REV. REL.	419,778	258,103	61.49%	114,862	27.36%	46,813	11.15%
12	REVENUE RELATED	6,843	4,040	59.04%	2,125	31.05%	678	9.91%
13	SUBTOTAL EXPENSES	426,621	262,143	61.45%	116,987	27.42%	47,491	11.13%
14	AMORTIZATION OF ITC	(878)	(673)	76.65%	(175)	19.93%	(30)	3.42%
15	OTHER AMORTIZATION	0	0	0.00%	0	0.00%	0	0.00%
16	TOTAL EXPENSES	425,743	261,470	61.41%	116,812	27.44%	47,461	11.15%

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Functionalize and classify test year operating expenses by primary account (depreciation expense, operation and maintenance expense and any other expense items). The balances in the C Schedules and those used in the cost of service study must be equal.

(000s)

Type of Data Shown:
X Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
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Witness: M. T. O'Sheasy

Allocation Method: 12MCP - 1/13th kWh

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
LINE NO.	OPERATING EXPENSE ACCOUNT NO. AND TITLE	ADJUSTED JURISDICTIONAL OPERATING EXPENSES	DEMAND AMOUNT	DEMAND PERCENT	CUSTOMER AMOUNT	CUSTOMER PERCENT	ENERGY AMOUNT	ENERGY PERCENT
1	OPERATING & MAINTENANCE:							
2	PRODUCTION	103,580	65,007	62.76%	0	0.00%	38,573	37.24%
3	TRANSMISSION							
4	560 - SUPERVISION	1,560	1,560	100.00%	0	0.00%	0	0.00%
5	561 - LOAD DISPATCH	3,419	3,419	100.00%	0	0.00%	0	0.00%
6	562 - STATION	42	42	100.00%	0	0.00%	0	0.00%
7	563 - OVERHEAD LINES	185	185	100.00%	0	0.00%	0	0.00%
8	564 - UNDERGROUND LINES	0	0	0.00%	0	0.00%	0	0.00%
9	566 - TRANS. OF ELEC.	(292)	(292)	100.00%	0	0.00%	0	0.00%
10	566 - MISCELLANEOUS	1,006	1,006	100.00%	0	0.00%	0	0.00%
11	567 - RENTS	160	160	100.00%	0	0.00%	0	0.00%
12	568 - SUPERVISION	1,021	1,021	100.00%	0	0.00%	0	0.00%
13	569 - STRUCTURES	973	973	100.00%	0	0.00%	0	0.00%
14	570 - STATION EQUIPMENT	811	811	100.00%	0	0.00%	0	0.00%
15	571 - OVERHEAD LINES	4,345	4,345	100.00%	0	0.00%	0	0.00%
16	573 - MISCELLANEOUS	99	99	100.00%	0	0.00%	0	0.00%
17	TOTAL TRANSMISSION	13,329	13,329	100.00%	0	0.00%	0	0.00%
18	DISTRIBUTION							
19	580 - SUPERVISION	6,761	3,367	49.80%	3,394	50.20%	0	0.00%
20	581 - LOAD DISPATCH	902	902	100.00%	0	0.00%	0	0.00%
21	582 - STATION	303	303	100.00%	0	0.00%	0	0.00%
22	583 - OVERHEAD LINES	2,579	2,579	100.00%	0	0.00%	0	0.00%
23	584 - UNDERGROUND LINES	739	739	100.00%	0	0.00%	0	0.00%
24	585 - STREET LIGHTING	598	0	0.00%	598	100.00%	0	0.00%
25	586 - METER	2,624	0	0.00%	2,624	100.00%	0	0.00%
26	587 - CUSTOMER INSTA.	1,331	0	0.00%	1,331	100.00%	0	0.00%
27	588 - MISCELLANEOUS	4,359	2,171	49.80%	2,188	50.20%	0	0.00%
28	589 - RENTS	0	0	0.00%	0	0.00%	0	0.00%
29	590 - SUPERVISION	3,660	3,504	95.74%	156	4.26%	0	0.00%
30	591 - STRUCTURES	27	27	100.00%	0	0.00%	0	0.00%
31	592 - STATION	946	946	100.00%	0	0.00%	0	0.00%
32	593 - OVERHEAD	13,075	13,077	100.02%	(2)	-0.02%	0	0.00%
33	594 - UNDERGROUND	1,697	1,697	100.00%	0	0.00%	0	0.00%
34	595 - LINE TRANS.	1,001	1,001	100.00%	0	0.00%	0	0.00%
35	596 - STREET LIGHTING	597	0	0.00%	597	100.00%	0	0.00%
36	597 - METERS	159	0	0.00%	159	100.00%	0	0.00%
37	598 - MISCELLANEOUS	472	452	95.76%	20	4.24%	0	0.00%
38	TOTAL DISTRIBUTION	42,030	30,965	73.67%	11,065	26.33%	0	0.00%

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Functionalize and classify test year operating expenses by primary account (depreciation expense, operation and maintenance expense and any other expense items). The balances in the C Schedules and those used in the cost of service study must be equal.

(000s)

Type of Data Shown:
X Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
___ Historical Year Ended 12/31/12
Witness: M. T. O'Sheasy

Allocation Method: 12MCP - 1/13th kWh

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
LINE NO.	OPERATING EXPENSE ACCOUNT NO. AND TITLE	ADJUSTED JURISDICTIONAL OPERATING EXPENSES	DEMAND AMOUNT	DEMAND PERCENT	CUSTOMER AMOUNT	CUSTOMER PERCENT	ENERGY AMOUNT	ENERGY PERCENT
1	CUSTOMER ACCOUNTS	21,807	0	0.00%	21,807	100.00%	0	0.00%
2	CUSTOMER ASSISTANCE	17,815	0	0.00%	17,815	100.00%	0	0.00%
3	ADMINISTRATION & GENERAL:							
4	PRODUCTION	37,711	34,160	90.58%	0	0.00%	3,551	9.42%
5	TRANSMISSION	4,627	4,627	100.00%	0	0.00%	0	0.00%
6	DISTRIBUTION	23,180	17,507	75.53%	5,673	24.47%	0	0.00%
7	CUSTOMER ACCOUNTS	9,541	0	0.00%	9,541	100.00%	0	0.00%
8	CUSTOMER ASSISTANCE	10,138	0	0.00%	10,138	100.00%	0	0.00%
9	TOTAL ADMIN. & GENERAL	85,197	56,294	66.07%	25,352	29.76%	3,551	4.17%
10	TOTAL OPERATION & MAINT.	283,758	165,595	58.36%	76,039	26.80%	42,124	14.84%
11	DEPRECIATION EXPENSE							
12	PRODUCTION	43,012	39,703	92.31%	0	0.00%	3,309	7.69%
13	TRANSMISSION							
14	350 - EASEMENTS	205	205	100.00%	0	0.00%	0	0.00%
15	352 - STRUCTURES	192	192	100.00%	0	0.00%	0	0.00%
16	353 - STATION EQUIP.	3,692	3,692	100.00%	0	0.00%	0	0.00%
17	354 - TOWERS	744	744	100.00%	0	0.00%	0	0.00%
18	355 - POLES	5,623	5,623	100.00%	0	0.00%	0	0.00%
19	356 - OVERHEAD	2,074	2,074	100.00%	0	0.00%	0	0.00%
20	358 - UNDERGROUND	246	246	100.00%	0	0.00%	0	0.00%
21	359 - ROAD & TRAILS	5	5	100.00%	0	0.00%	0	0.00%
22	TOTAL TRANSMISSION	12,781	12,781	100.00%	0	0.00%	0	0.00%
23	DISTRIBUTION							
24	360 - EASEMENTS	13	13	100.00%	0	0.00%	0	0.00%
25	361 - STRUCTURES	433	433	100.00%	0	0.00%	0	0.00%
26	362 - STATION EQUIP.	5,107	5,107	100.00%	0	0.00%	0	0.00%
27	364 - POLES & FIXTURES	6,282	6,282	100.00%	0	0.00%	0	0.00%
28	365 - OVERHEAD COND.	4,398	4,398	100.00%	0	0.00%	0	0.00%
29	366 - UNDERGROUND CONDUIT	14	14	100.00%	0	0.00%	0	0.00%
30	367 - UNDERGROUND COND.	4,533	4,533	100.00%	0	0.00%	0	0.00%

Supporting Schedules: Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Functionalize and classify test year operating expenses by primary account (depreciation expense, operation and maintenance expense and any other expense items). The balances in the C Schedules and those used in the cost of service study must be equal.

(000s)

Type of Data Shown:
X Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
___ Historical Year Ended 12/31/12
Witness: M. T. O'Sheasy

Allocation Method: 12MCP - 1/13th kWh

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
LINE NO.	OPERATING EXPENSE ACCOUNT NO. AND TITLE	ADJUSTED JURISDICTIONAL OPERATING EXPENSES	DEMAND AMOUNT	DEMAND PERCENT	CUSTOMER AMOUNT	CUSTOMER PERCENT	ENERGY AMOUNT	ENERGY PERCENT
1	368 - LINE TRANSFORMERS	9,621	9,621	100.00%	0	0.00%	0	0.00%
2	369 - SERVICES	2,838	0	0.00%	2,838	100.00%	0	0.00%
3	370 - METERS	4,477	0	0.00%	4,477	100.00%	0	0.00%
4	373 - STREET LIGHTING	2,871	0	0.00%	2,871	100.00%	0	0.00%
5	TOTAL DISTRIBUTION	40,587	30,401	74.90%	10,186	25.10%	0	0.00%
6	GENERAL:							
7	PRODUCTION	3,759	3,470	92.31%	0	0.00%	289	7.69%
8	TRANSMISSION	330	330	100.00%	0	0.00%	0	0.00%
9	DISTRIBUTION	1,814	1,336	73.65%	478	26.35%	0	0.00%
10	CUSTOMER ACCOUNTS	1,077	0	0.00%	1,077	100.00%	0	0.00%
11	CUSTOMER ASSISTANCE	1,145	0	0.00%	1,145	100.00%	0	0.00%
12	TOTAL GENERAL	8,125	5,136	63.21%	2,700	33.23%	289	3.56%
13	TOTAL DEPRECIATION EXP.	104,505	88,021	84.23%	12,886	12.33%	3,598	3.44%
14	REAL & PERS. PROP. TXS.:							
15	PRODUCTION	15,809	14,593	92.31%	0	0.00%	1,216	7.69%
16	TRANSMISSION	2,513	2,513	100.00%	0	0.00%	0	0.00%
17	DISTRIBUTION	5,946	4,758	80.02%	1,188	19.98%	0	0.00%
18	CUSTOMER ACCOUNTS	119	0	0.00%	119	100.00%	0	0.00%
19	CUSTOMER ASSISTANCE	128	0	0.00%	128	100.00%	0	0.00%
20	TOTAL REAL & PERS. PROP TXS	24,515	21,864	89.19%	1,435	5.85%	1,216	4.96%
21	PAYROLL TAXES:							
22	PRODUCTION	2,753	2,882	104.89%	0	0.00%	(129)	-4.89%
23	TRANSMISSION	287	287	100.00%	0	0.00%	0	0.00%
24	DISTRIBUTION	1,599	1,177	73.61%	422	26.39%	0	0.00%
25	CUSTOMER ACCOUNTS	950	0	0.00%	950	100.00%	0	0.00%
26	CUSTOMER ASSISTANCE	1,010	0	0.00%	1,010	100.00%	0	0.00%
27	TOTAL PAYROLL TAXES	6,599	4,346	65.86%	2,382	36.10%	(129)	-1.96%

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Functionalize and classify test year operating expenses by primary account (depreciation expense, operation and maintenance expense and any other expense items). The balances in the C Schedules and those used in the cost of service study must be equal.

(000s)

Type of Data Shown:
X Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
___ Historical Year Ended 12/31/12
Witness: M. T. O'Sheasy

Allocation Method: 12MCP - 1/13th kWh

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
LINE NO.	OPERATING EXPENSE ACCOUNT NO. AND TITLE	ADJUSTED JURISDICTIONAL OPERATING EXPENSES	DEMAND AMOUNT	DEMAND PERCENT	CUSTOMER AMOUNT	CUSTOMER PERCENT	ENERGY AMOUNT	ENERGY PERCENT
1	MISS. FRANCHISE TAXES	298	298	100.00%	0	0.00%	0	0.00%
2	MISCELLANEOUS TAXES:							
3	PRODUCTION	46	42	91.30%	0	0.00%	4	8.70%
4	TRANSMISSION	4	4	100.00%	0	0.00%	0	0.00%
5	DISTRIBUTION	24	18	75.00%	6	25.00%	0	0.00%
6	CUSTOMER ACCOUNTS	14	0	0.00%	14	100.00%	0	0.00%
7	CUSTOMER ASSISTANCE	15	0	0.00%	15	100.00%	0	0.00%
8	TOTAL MISCELLANEOUS TAXES	103	64	62.14%	35	33.98%	4	3.88%
9	TOTAL TAXES OTHER THAN							
10	INCOME TAXES	31,515	26,572	84.32%	3,852	12.22%	1,091	3.46%
11	TOTAL EXPENSES EXCL. REV. REL.	419,778	280,188	66.75%	92,777	22.10%	46,813	11.15%
12	REVENUE RELATED	6,843	4,448	65.00%	1,714	25.05%	681	9.95%
13	SUBTOTAL EXPENSES	426,621	284,636	66.72%	94,491	22.15%	47,494	11.13%
14	AMORTIZATION OF ITC	(878)	(739)	84.16%	(109)	12.42%	(30)	3.42%
15	OTHER AMORTIZATION	0	0	0.00%	0	0.00%	0	0.00%
16	TOTAL EXPENSES	425,743	283,897	66.68%	94,382	22.17%	47,464	11.15%

Schedule E-5 | SOURCE AND AMOUNT OF REVENUES - AT PRESENT AND PROPOSED RATES | Page 1 of 4

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide a schedule by rate class which identifies the source and amount of ALL revenue INCLUDED IN THE COST OF SERVICE STUDY. The base rate revenue from retail sales of electricity must equal that shown on MFR Schedule E-13a. The revenue from service charges must equal that shown on MFR Schedule E-13b. The total revenue for the retail system must equal that shown on MFR Schedule E-13b.

Type of Data Shown:
X Projected Test Year Ended 12/31/14
__ Prior Year Ended 12/31/13
__ Historical Year Ended 12/31/12
Witness: M. T. O'Sheasy

($000s)

Allocation Method: 12MCP - 1/13th kWh - Minimum Distribution System

(1) LINE NO.	(2) ACCT. NO.	(3) DESCRIPTION	(4) TOTAL ELECTRIC SYSTEM	(5) WHOLESALE	(6) TOTAL RETAIL SERVICE	(7) RATE CLASS RESIDENTIAL	(8) RATE CLASS GS	(9) RATE CLASS GSD/GSDT	(10) RATE CLASS LP/LPT	(11) RATE CLASS MAJOR ACCTS	(12) RATE CLASS OS	(13) UPS
1		PRESENT REVENUES										
2	440 -	SALES OF ELECTRICITY	510,734	12,241	498,493	296,890	20,537	102,785	33,933	29,452	14,896	0
3	447											
4	451	MISC. SERVICE CHARGES:										
5		RESTORATION FEE	1,213	0	1,213	1,174	31	8	0	0	0	0
6		AFTER HOURS FEE	116	0	116	115	1	0	0	0	0	0
7		INACCESSIBLE METER FEE	26	0	26	19	2	5	0	0	0	0
8		CUST. RECONNECTION FEES	2,823	0	2,823	2,696	84	43	0	0	0	0
9		FRANCHISE CHARGES	42,247	0	42,247	25,162	1,740	8,711	2,876	2,498	1,262	0
10		INSTALL. & REM.-TEMP SER	0	0	0	0	0	0	0	0	0	0
11		CUST. CONNECTION FEES	92	0	92	77	13	2	0	0	0	0
12		COLLECTION CHARGES	207	0	207	161	24	22	0	0	0	0
13		INVESTIGATIVE CHARGES	40	0	40	38	2	0	0	0	0	0
14		BAD CHECK FEES	272	0	272	258	6	8	0	0	0	0
15		TOTAL MISC. SERVICE CHGS.	47,036	0	47,036	29,700	1,903	8,799	2,876	2,498	1,262	0
16	454	RENT FROM ELEC. PROPERTY:										
17		EQUIPMENT RENTAL	1,686	0	1,686	1,045	57	435	119	3	27	0
18		METER TREATER RENTAL	253	0	253	244	7	2	0	0	0	0
19		POLE ATTACHMENT RENTAL	3,110	0	3,110	2,411	169	343	91	32	64	0
20		MICROWAVE TRANSPORT	730	12	718	453	37	124	44	47	13	0
21		RENT FROM PLANT DANIEL	40	1	39	22	1	8	4	4	0	0
22		MISCELLANEOUS RENTS	516	8	508	321	26	88	31	33	9	0
23		TOTAL RENT FROM ELEC. PROP	6,335	21	6,314	4,498	297	1,000	289	119	113	0
24	455	INTERDEPARTMENTAL RENTAL	0	0	0	0	0	0	0	0	0	0

Supporting Schedules: E-13a, E-13b

Recap Schedules:

Schedule E-5 | SOURCE AND AMOUNT OF REVENUES - AT PRESENT AND PROPOSED RATES | Page 2 of 4

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide a schedule by rate class which identifies the source and amount of ALL revenue INCLUDED IN THE COST OF SERVICE STUDY. The base rate revenue from retail sales of electricity must equal that shown on MFR Schedule E-13a. The revenue from service charges must equal that shown on MFR Schedule E-13b. The total revenue for the retail system must equal that shown on MFR Schedule E-13b.

Type of Data Shown:
X Projected Test Year Ended 12/31/14
_ Prior Year Ended 12/31/13
_ Historical Year Ended 12/31/12
Witness: M. T. O'Sheasy

($000s)

Allocation Method: 12MCP - 1/13th kWh - Minimum Distribution System

(1) LINE NO.	(2) ACCT. NO.	(3) DESCRIPTION	(4) TOTAL ELECTRIC SYSTEM	(5) WHOLESALE	(6) TOTAL RETAIL SERVICE	(7) RATE CLASS RESIDENTIAL	(8) RATE CLASS GS	(9) RATE CLASS GSD/GSDT	(10) RATE CLASS LP/LPT	(11) RATE CLASS MAJOR ACCTS	(12) RATE CLASS OS	(13) UPS
1	456	OTHER ELECTRIC REVENUES	6,368	190	6,178	3,390	165	1,336	569	692	26	0
2		GULF POWER ENGY SRVC REV	5,632	0	5,632	0	0	0	5,632	0	0	0
3		FPU SERVICE PAYMENTS	3,678	3,678	0	0	0	0	0	0	0	0
4		BLOUNTSTOWN SERVICE PAY	122	4	118	65	3	26	11	13	0	0
5		TOTAL OTHER ELEC. REVENUES	15,800	3,872	11,928	3,455	168	1,362	6,212	705	26	0
6		REVENUE NONASSOC. COS.	65,602	214	7,127	3,389	168	1,760	784	907	99	58,261
7		TOTAL OTHER OPER. REVS.	134,773	4,107	72,405	41,040	2,556	12,921	10,161	4,227	1,500	58,261
8		ADJUSTMENTS TO REVENUE:										
9		FRANCHISE FEE REVENUES	(42,247)	0	(42,247)	(25,162)	(1,740)	(8,711)	(2,676)	(2,496)	(1,262)	0
10		TOTAL ADJUSTED REVENUES	603,260	16,348	528,651	312,768	21,353	106,995	41,218	31,183	15,134	58,261
11		PROPOSED REVENUES										
12	440 -	SALES OF ELECTRICITY	74,393	0	74,393	44,303	2,372	13,194	7,104	6,570	850	0
13	447											
14	451	MISC. SERVICE CHARGES	0	0	0	0	0	0	0	0	0	0
15		TOTAL ADJUSTED REVENUES	74,393	0	74,393	44,303	2,372	13,194	7,104	6,570	850	0

Supporting Schedules: E-13a, E-13b

Recap Schedules:

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Schedule E-5 | SOURCE AND AMOUNT OF REVENUES - AT PRESENT AND PROPOSED RATES | Page 3 of 4

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide a schedule by rate class which identifies the source and amount of ALL revenue INCLUDED IN THE COST OF SERVICE STUDY. The base rate revenue from retail sales of electricity must equal that shown on MFR Schedule E-13a. The revenue from service charges must equal that shown on MFR Schedule E-13b. The total revenue for the retail system must equal that shown on MFR Schedule E-13b.

Type of Data Shown:
X Projected Test Year Ended 12/31/14
__ Prior Year Ended 12/31/13
__ Historical Year Ended 12/31/12
Witness: M. T. O'Sheasy

($000s)

Allocation Method: 12MCP - 1/13th kWh

(1) LINE NO.	(2) ACCT. NO.	(3) DESCRIPTION	(4) TOTAL ELECTRIC SYSTEM	(5) WHOLESALE	(6) TOTAL RETAIL SERVICE	(7) RATE CLASS RESIDENTIAL	(8) RATE CLASS GS	(9) RATE CLASS GSD/GSDT	(10) RATE CLASS LP/LPT	(11) RATE CLASS MAJOR ACCTS	(12) RATE CLASS OS	(13) LIPS
1		PRESENT REVENUES										
2	440 -	SALES OF ELECTRICITY	510,734	12,241	498,493	296,890	20,537	102,785	33,933	29,452	14,896	0
3	447											
4	451	MISC. SERVICE CHARGES:										
5		RESTORATION FEE	1,213	0	1,213	1,174	31	8	0	0	0	0
6		AFTER HOURS FEE	116	0	116	115	1	0	0	0	0	0
7		INACCESSIBLE METER FEE	28	0	28	19	2	5	0	0	0	0
8		CUST. RECONNECTION FEES	2,823	0	2,823	2,696	84	43	0	0	0	0
9		FRANCHISE CHARGES	42,247	0	42,247	25,162	1,740	8,711	2,876	2,496	1,262	0
10		INSTALL. & REM.-TEMP SER	0	0	0	0	0	0	0	0	0	0
11		CUST. CONNECTION FEES	92	0	92	77	13	2	0	0	0	0
12		COLLECTION CHARGES	207	0	207	161	24	22	0	0	0	0
13		INVESTIGATIVE CHARGES	40	0	40	38	2	0	0	0	0	0
14		BAD CHECK FEES	272	0	272	258	8	8	0	0	0	0
15		TOTAL MISC. SERVICE CHGS.	47,036	0	47,036	29,700	1,903	8,799	2,876	2,496	1,262	0
16	454	RENT FROM ELEC. PROPERTY:										
17		EQUIPMENT RENTAL	1,686	0	1,686	1,045	57	435	119	3	27	0
18		METER TREATER RENTAL	253	0	253	244	7	2	0	0	0	0
19		POLE ATTACHMENT RENTAL	3,110	0	3,110	1,841	99	768	263	92	47	0
20		MICROWAVE TRANSPORT	730	12	718	446	35	131	46	47	13	0
21		RENT FROM PLANT DANIEL	40	1	39	22	1	8	4	4	0	0
22		MISCELLANEOUS RENTS	516	8	508	315	25	93	33	33	9	0
23		TOTAL RENT FROM ELEC. PROP	6,335	21	6,314	3,913	224	1,437	465	179	96	0
24	455	INTERDEPARTMENTAL RENTAL	0	0	0	0	0	0	0	0	0	0

Supporting Schedules: E-13a, E-13b

Recap Schedules:

Schedule E-5 | SOURCE AND AMOUNT OF REVENUES - AT PRESENT AND PROPOSED RATES | Page 4 of 4

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide a schedule by rate class which identifies the source and amount of ALL revenue INCLUDED IN THE COST OF SERVICE STUDY. The base rate revenue from retail sales of electricity must equal that shown on MFR Schedule E-13a. The revenue from service charges must equal that shown on MFR Schedule E-13b. The total revenue for the retail system must equal that shown on MFR Schedule E-13b.

Type of Data Shown:
X Projected Test Year Ended 12/31/14
__ Prior Year Ended 12/31/13
__ Historical Year Ended 12/31/12
Witness: M. T. O'Sheasy

($000s)

Allocation Method: 12MCP - 1/13th kWh

(1) LINE NO.	(2) ACCT. NO.	(3) DESCRIPTION	(4) TOTAL ELECTRIC SYSTEM	(5) WHOLESALE	(6) TOTAL RETAIL SERVICE	(7) RATE CLASS RESIDENTIAL	(8) RATE CLASS GS	(9) RATE CLASS GSD/GSDT	(10) RATE CLASS LP/LPT	(11) RATE CLASS MAJOR ACCTS	(12) RATE CLASS OS	(13) UPS
1	456	OTHER ELECTRIC REVENUES	6,368	190	6,178	3,390	165	1,336	569	692	26	0
2		GULF POWER ENGY SRVC REV	5,632	0	5,632	0	0	0	5,632	0	0	0
3		FPU SERVICE PAYMENTS	3,678	3,678	0	0	0	0	0	0	0	0
4		BLOUNTSTOWN SERVICE PAY	122	4	118	65	3	26	11	13	0	0
5		TOTAL OTHER ELEC. REVENUES	15,800	3,872	11,928	3,455	168	1,362	6,212	705	26	0
6		REVENUE NONASSOC. COS.	65,602	214	7,127	3,389	168	1,760	784	907	99	58,261
7		TOTAL OTHER OPER. REVS.	134,773	4,107	72,405	40,457	2,483	13,358	10,337	4,287	1,483	58,261
8		ADJUSTMENTS TO REVENUE:										
9		FRANCHISE FEE REVENUES	(42,247)	0	(42,247)	(25,162)	(1,740)	(8,711)	(2,876)	(2,496)	(1,262)	0
10		TOTAL ADJUSTED REVENUES	603,260	16,348	528,651	312,165	21,280	107,432	41,394	31,243	15,117	58,261
11		PROPOSED REVENUES										
12	440 -	SALES OF ELECTRICITY	74,393	0	74,393	44,303	2,372	13,194	7,104	6,570	850	0
13	447											
14	451	MISC. SERVICE CHARGES	0	0	0	0	0	0	0	0	0	0
15		TOTAL ADJUSTED REVENUES	74,393	0	74,393	44,303	2,372	13,194	7,104	6,570	850	0

Supporting Schedules: E-13a, E-13b

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: For each cost of service study filed by the company, calculate the unit costs for demand, energy and customer for each rate schedule at present rates, based on the revenue requirements from sales of electricity only, excluding other operating revenues. The demand unit costs must be separated into production, transmission and distribution. Unit costs under present rates must be calculated at both the system and class rates of return. Unit costs must be provided separately for each existing rate class, except for the lighting classes. If the company is proposing to combine two or more classes, it must also provide unit costs for the classes combined. Customer unit costs for the lighting classes must include only customer-related costs, excluding costs for fixtures and poles. The lighting fixtures and poles must be shown on a separate line. Billing units must match Schedule E-5.Customer unit costs for the lighting classes must include only customer-related costs, excluding costs for fixtures and poles. The lighting fixtures and poles must be shown on a separate line. Billing units must match Schedule E-5.

Type of Data Shown:
X Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
___ Historical Year Ended 12/31/12
Witness: M. T. O'Sheasy

($000s)

CLASS (RATES) RATE OF RETURN

Allocation Method: 12MCP - 1/13th kWh - Minimum Distribution System

(1) LINE NO.	(2) DESCRIPTION	(3) TOTAL RETAIL SERVICE	(4) RATE CLASS RESIDENTIAL	(5) RATE CLASS GS	(6) RATE CLASS GSD/GSDT	(7) RATE CLASS LP/LPT	(8) RATE CLASS MAJOR ACCTS	(9) RATE CLASS OS
1	REVENUE REQUIREMENTS FROM							
2	SALE OF ELECTRICITY ($000)							
3	ENERGY (NON-FUEL PORTION)	47,704	22,859	1,279	12,638	5,073	5,091	764
4	DEMAND	330,580	185,700	9,601	80,955	28,000	23,706	2,618
5	PRODUCTION	191,612	106,068	5,288	44,394	16,969	17,975	918
6	TRANSMISSION	46,943	26,280	1,369	12,070	3,920	3,025	279
7	DISTRIBUTION	92,025	53,352	2,944	24,491	7,111	2,706	1,421
8	CUSTOMER	120,205	88,327	9,654	9,194	866	650	11,514
9	DISTRIBUTION	52,676	44,179	4,000	3,514	134	51	799
10	CUSTOMER ACCOUNTS	31,364	27,259	2,203	1,321	34	59	488
11	CUSTOMER ASSISTANCE	25,937	16,889	3,451	4,369	698	540	0
12	CUSTOMER (LIGHTING FACIL)	10,228	0	0	0	0	0	10,228
13	TOTAL REVENUE REQUIREMENT	498,489	296,886	20,534	102,787	33,939	29,447	14,896
14	BILLING UNITS (ANNUAL)							
15	ENERGY (MWH)		5,264,445	291,283	2,733,687	1,233,654	1,477,619	153,590
16	BILLING DEMAND (KW)		-	-	8,569,894	2,539,002	887,068	-
17	SBS BILLING KW FOR RSRV CHG		-	-	-	-	89,448	-
18	CUSTOMER		4,632,396	349,872	209,964	3,408	816	123,744
19	UNIT COST							
20	ENERGY (¢/KWH)		0.43421	0.43909	0.46231	0.41122	0.34454	0.49743
21	CUSTOMER($/CUST/MO OR ¢/KWH)		19.07	27.59	43.79	254.11	796.57	10.39
22	CUSTOMER (LIGHTING FACIL.)							
23	($/CUSTOMER/MO)		-	-	-	-	-	82.65
24	DEMAND - PRODUCTION - $/KW		-	-	5.18	6.68	10.12 [1]	-
25	DEMAND - TRANSMISSION - $/KW		-	-	1.41	1.54	3.06 [1]	-
26	DEMAND - DISTRIBUTION - $/KW		-	-	2.86	2.80	0.66 [1]	-
27	DEMAND - PRODUCTION - ¢/KWH		2.01480	1.81542	1.62396	1.37551	1.21648	0.59770
28	DEMAND - TRANSMISSION- ¢/KWH		0.49920	0.46999	0.44153	0.31776	0.20472	0.18165
29	DEMAND - DISTRIBUTION- ¢/KWH		1.01344	1.01070	0.89990	0.57642	0.18313	0.92519
30	1 $/KW Based on Rate Class SBS							

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: For each cost of service study filed by the company, calculate the unit costs for demand, energy and customer for each rate schedule at present rates, based on the revenue requirements from sales of electricity only, excluding other operating revenues. The demand unit costs must be separated into production, transmission and distribution. Unit costs under present rates must be calculated at both the system and class rates of return. Unit costs must be provided separately for each existing rate class, except for the lighting classes. If the company is proposing to combine two or more classes, it must also provide unit costs for the classes combined. Customer unit costs for the lighting classes must include only customer-related costs, excluding costs for fixtures and poles. The lighting fixtures and poles must be shown on a separate line. Billing units must match Schedule E-5.Customer unit costs for the lighting classes must include only customer-related costs, excluding costs for fixtures and poles. The lighting fixtures and poles must be shown on a separate line. Billing units must match Schedule E-5.

Type of Data Shown:
X Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
___ Historical Year Ended 12/31/12
Witness: M. T. O'Sheasy

($000s)

SYSTEM (EQUAL) RATE OF RETURN

Allocation Method: 12MCP - 1/13th kWh - Minimum Distribution System

(1) LINE NO.	(2) DESCRIPTION	(3) TOTAL RETAIL SERVICE	(4) RATE CLASS RESIDENTIAL	(5) RATE CLASS GS	(6) RATE CLASS GSD/GSDT	(7) RATE CLASS LP/LPT	(8) RATE CLASS MAJOR ACCTS	(9) RATE CLASS OS
1	REVENUE REQUIREMENTS FROM							
2	SALE OF ELECTRICITY ($000)							
3	ENERGY (NON-FUEL PORTION)	48,002	22,818	1,250	11,880	5,279	6,110	665
4	DEMAND	331,952	186,446	9,286	73,839	29,754	30,514	2,113
5	PRODUCTION	193,269	106,421	5,168	41,653	17,685	21,549	793
6	TRANSMISSION	47,847	26,500	1,294	10,364	4,359	5,129	201
7	DISTRIBUTION	90,836	53,525	2,824	21,822	7,710	3,836	1,119
8	CUSTOMER	118,536	88,998	9,512	8,845	880	667	9,634
9	DISTRIBUTION	52,802	44,838	3,880	3,228	141	52	663
10	CUSTOMER ACCOUNTS	31,343	27,286	2,196	1,310	34	59	478
11	CUSTOMER ASSISTANCE	25,898	16,894	3,436	4,307	705	556	0
12	CUSTOMER (LIGHTING FACIL)	8,493	0	0	0	0	0	8,493
13	TOTAL REVENUE REQUIREMENT	498,490	298,262	20,048	94,564	35,913	37,291	12,412
14	BILLING UNITS (ANNUAL)							
15	ENERGY (MWH)		5,264,446	291,283	2,733,687	1,233,654	1,477,619	153,590
16	BILLING DEMAND (KW)		-	-	8,569,894	2,539,002	887,068	-
17	SBS BILLING KW FOR RSRV CHG		-	-	-	-	89,448	-
18	CUSTOMER		4,632,396	349,872	209,964	3,408	816	123,744
19	UNIT COST							
20	ENERGY (¢/KWH)		0.43344	0.42914	0.43458	0.42792	0.41350	0.43297
21	CUSTOMER($/CUST/MO OR ¢/KWH)		19.21	27.19	42.13	258.22	817.40	9.22
22	CUSTOMER(LIGHTING FACIL.)							
23	($/CUSTOMER/MO)		-	-	-	-	-	68.63
24	DEMAND - PRODUCTION - $/KW		-	-	4.86	6.97	7.93 [1]	-
25	DEMAND - TRANSMISSION - $/KW		-	-	1.21	1.72	1.82 [1]	-
26	DEMAND - DISTRIBUTION - $/KW		-	-	2.55	3.04	0.37 [1]	-
27	DEMAND - PRODUCTION - ¢/KWH		2.02150	1.77422	1.52369	1.43355	1.45836	0.51631
28	DEMAND - TRANSMISSION- ¢/KWH		0.50338	0.44424	0.37912	0.35334	0.34711	0.13087
29	DEMAND - DISTRIBUTION- ¢/KWH		1.01673	0.96950	0.79826	0.82497	0.25961	0.72856
30	1 $/KW Based on Rate Class SBS							

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: For each cost of service study filed by the company, calculate the unit costs for demand, energy and customer for each rate schedule at present rates, based on the revenue requirements from sales of electricity only, excluding other operating revenues. The demand unit costs must be separated into production, transmission and distribution. Unit costs under present rates must be calculated at both the system and class rates of return. Unit costs must be provided separately for each existing rate class, except for the lighting classes. If the company is proposing to combine two or more classes, it must also provide unit costs for the classes combined. Customer unit costs for the lighting classes must include only customer-related costs, excluding costs for fixtures and poles. The lighting fixtures and poles must be shown on a separate line. Billing units must match Schedule E-5.Customer unit costs for the lighting classes must include only customer-related costs, excluding costs for fixtures and poles. The lighting fixtures and poles must be shown on a separate line. Billing units must match Schedule E-5.

Type of Data Shown:
X Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
___ Historical Year Ended 12/31/12
Witness: M. T. O'Sheasy

($000s)

CLASS (RATES) RATE OF RETURN

Allocation Method: 12MCP - 1/13th kWh

(1) LINE NO.	(2) DESCRIPTION	(3) TOTAL RETAIL SERVICE	(4) RATE CLASS RESIDENTIAL	(5) RATE CLASS GS	(6) RATE CLASS GSD/GSDT	(7) RATE CLASS LP/LPT	(8) RATE CLASS MAJOR ACCTS	(9) RATE CLASS OS
1	REVENUE REQUIREMENTS FROM							
2	SALE OF ELECTRICITY ($000)							
3	ENERGY (NON-FUEL PORTION)	47,462	23,323	1,336	12,116	4,878	5,035	774
4	DEMAND	356,998	207,748	11,170	82,892	28,247	23,763	3,178
5	PRODUCTION	191,279	108,254	5,528	42,498	16,291	17,777	933
6	TRANSMISSION	46,746	27,620	1,514	10,904	3,507	2,911	290
7	DISTRIBUTION	116,973	71,874	4,128	29,492	8,448	3,075	1,955
8	CUSTOMER	94,040	65,821	8,032	7,783	809	646	10,949
9	DISTRIBUTION	26,156	21,515	2,330	2,144	84	48	35
10	CUSTOMER ACCOUNTS	31,468	27,353	2,220	1,314	34	59	488
11	CUSTOMER ASSISTANCE	25,990	18,953	3,482	4,325	691	539	0
12	CUSTOMER (LIGHTING FACIL)	10,426	0	0	0	0	0	10,426
13	TOTAL REVENUE REQUIREMENT	496,500	296,892	20,538	102,791	33,934	29,444	14,901
14	BILLING UNITS (ANNUAL)							
15	ENERGY (MWH)		5,264,446	291,283	2,733,687	1,233,654	1,477,819	163,590
16	BILLING DEMAND (KW)		-	-	8,569,894	2,539,002	887,068	-
17	SBS BILLING KW FOR RSRV CHG		-	-	-	-	89,448	-
18	CUSTOMER		4,632,396	349,872	209,964	3,408	818	123,744
19	UNIT COST							
20	ENERGY (¢/KWH)		0.44303	0.45866	0.44321	0.39541	0.34075	0.50394
21	CUSTOMER($/CUST/MO OR ¢/KWH)		14.21	22.96	37.07	237.38	791.67	4.23
22	CUSTOMER (LIGHTING FACIL.)							
23	($/CUSTOMER/MO)		-	-	-	-	-	84.25
24	DEMAND - PRODUCTION - $/KW		-	-	4.96	8.42	10.12 [1]	-
25	DEMAND - TRANSMISSION - $/KW		-	-	1.27	1.38	3.06 [1]	-
26	DEMAND - DISTRIBUTION - $/KW		-	-	3.44	3.33	0.66 [1]	-
27	DEMAND - PRODUCTION - ¢/KWH		2.05632	1.89781	1.55463	1.32055	1.20308	0.60746
28	DEMAND - TRANSMISSION- ¢/KWH		0.52465	0.51977	0.39888	0.28428	0.19701	0.18881
29	DEMAND - DISTRIBUTION- ¢/KWH		1.36527	1.41718	1.07884	0.68488	0.20811	1.27287
30	1 $/KW Based on Rate Class SBS							

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: For each cost of service study filed by the company, calculate the unit costs for demand, energy and customer for each rate schedule at present rates, based on the revenue requirements from sales of electricity only, excluding other operating revenues. The demand unit costs must be separated into production, transmission and distribution. Unit costs under present rates must be calculated at both the system and class rates of return. Unit costs must be provided separately for each existing rate class, except for the lighting classes. If the company is proposing to combine two or more classes, it must also provide unit costs for the classes combined. Customer unit costs for the lighting classes must include only customer-related costs, excluding costs for fixtures and poles. The lighting fixtures and poles must be shown on a separate line. Billing units must match Schedule E-5.Customer unit costs for the lighting classes must include only customer-related costs, excluding costs for fixtures and poles. The lighting fixtures and poles must be shown on a separate line. Billing units must match Schedule E-5.

Type of Data Shown:
X Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
___ Historical Year Ended 12/31/12
Witness: M. T. O'Sheasy

($000s)

SYSTEM (EQUAL) RATE OF RETURN

Allocation Method: 12MCP - 1/13th kWh

(1) LINE NO.	(2) DESCRIPTION	(3) TOTAL RETAIL SERVICE	(4) RATE CLASS RESIDENTIAL	(5) RATE CLASS GS	(6) RATE CLASS GSD/GSDT	(7) RATE CLASS LP/LPT	(8) RATE CLASS MAJOR ACCTS	(9) RATE CLASS OS
1	REVENUE REQUIREMENTS FROM							
2	SALE OF ELECTRICITY ($000)							
3	ENERGY (NON-FUEL PORTION)	48,009	22,831	1,253	11,876	5,278	6,108	663
4	DEMAND	358,705	202,594	10,163	80,454	31,874	31,093	2,527
5	PRODUCTION	193,292	108,465	5,175	41,628	17,681	21,549	794
6	TRANSMISSION	47,861	26,507	1,295	10,363	4,360	5,131	205
7	DISTRIBUTION	117,552	69,622	3,693	28,463	9,833	4,413	1,528
8	CUSTOMER	91,783	65,784	7,774	7,705	833	663	9,024
9	DISTRIBUTION	26,002	21,609	2,135	2,085	95	49	29
10	CUSTOMER ACCOUNTS	31,359	27,279	2,199	1,311	34	59	477
11	CUSTOMER ASSISTANCE	25,904	16,896	3,440	4,309	704	555	0
12	CUSTOMER (LIGHTING FACIL)	8,518	0	0	0	0	0	8,518
13	TOTAL REVENUE REQUIREMENT	498,497	291,209	19,190	100,035	37,985	37,864	12,214
14	BILLING UNITS (ANNUAL)							
15	ENERGY (MWH)		5,264,445	291,283	2,733,687	1,233,654	1,477,619	153,590
16	BILLING DEMAND (KW)		-	-	8,569,894	2,539,002	687,068	-
17	SBS BILLING KW FOR RSRV CHG		-	-	-	-	89,448	-
18	CUSTOMER		4,632,396	349,872	209,964	3,408	816	123,744
19	UNIT COST							
20	ENERGY (¢/KWH)		0.43368	0.43017	0.43443	0.42783	0.41337	0.43167
21	CUSTOMER($/CUST/MO OR ¢/KWH)		14.20	22.22	36.70	244.42	812.50	4.09
22	CUSTOMER(LIGHTING FACIL.)							
23	($/CUSTOMER/MO)		-	-	-	-	-	68.84
24	DEMAND - PRODUCTION - $/KW		-	-	4.86	6.96	7.93 [1]	-
25	DEMAND - TRANSMISSION - $/KW		-	-	1.21	1.72	1.82 [1]	-
26	DEMAND - DISTRIBUTION - $/KW		-	-	3.32	3.87	0.37 [1]	-
27	DEMAND - PRODUCTION - ¢/KWH		2.02234	1.77662	1.52278	1.43322	1.45836	0.51696
28	DEMAND - TRANSMISSION- ¢/KWH		0.50351	0.44458	0.37909	0.35342	0.34725	0.13347
29	DEMAND - DISTRIBUTION- ¢/KWH		1.32249	1.26784	1.04119	0.79706	0.29866	0.99486
30	1 $/KW Based on Rate Class SBS							

Supporting Schedules:

Recap Schedules:

Schedule E-6b | COST OF SERVICE STUDY - UNIT COSTS, PROPOSED RATES | Page 1 of 2

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: For each cost of service study filed by the company, calculate the unit costs for demand, energy and customer for each rate schedule at proposed rates, based on the revenue requirements from sales of electricity only, excluding other operating revenues. The demand unit costs must be separated into production, transmission and distribution. Unit costs under proposed rates must be calculated at the system rate of return. Unit costs must be provided separately for each existing rate class, except for the lighting classes. If the company is proposing to combine two or more classes, it must also provide unit costs for the classes combined. Customer unit costs for the lighting classes must include only customer-related costs, excluding costs for fixtures and poles. The lighting fixtures and poles must be shown on a separate line. Billing units must match Schedule E-5.

Type of Data Shown:
X Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
___ Historical Year Ended 12/31/12
Witness: M. T. O'Sheasy

($000s)

SYSTEM (EQUAL) RATE OF RETURN

Allocation Method: 12MCP - 1/13th kWh - Minimum Distribution System

(1) LINE NO.	(2) DESCRIPTION	(3) TOTAL RETAIL SERVICE	(4) RATE CLASS RESIDENTIAL	(5) RATE CLASS GS	(6) RATE CLASS GSD/GSDT	(7) RATE CLASS LP/LPT	(8) RATE CLASS MAJOR ACCTS	(9) RATE CLASS OS
1	REVENUE REQUIREMENTS FROM							
2	SALE OF ELECTRICITY ($000)							
3	ENERGY (NON-FUEL PORTION)	53,619	25,491	1,398	13,268	5,897	6,824	741
4	DEMAND	390,117	219,109	10,920	86,898	34,999	35,686	2,505
5	PRODUCTION	216,520	119,181	5,788	46,683	19,825	24,153	890
6	TRANSMISSION	62,209	34,435	1,681	13,494	5,674	6,664	261
7	DISTRIBUTION	111,388	65,493	3,451	26,721	9,500	4,869	1,354
8	CUSTOMER	129,152	96,719	10,246	9,490	918	686	11,093
9	DISTRIBUTION	60,955	51,709	4,503	3,756	160	59	768
10	CUSTOMER ACCOUNTS	31,888	27,744	2,232	1,331	34	61	486
11	CUSTOMER ASSISTANCE	26,470	17,266	3,511	4,403	724	566	0
12	CUSTOMER (LIGHTING FACIL)	9,839	0	0	0	0	0	9,839
13	TOTAL REVENUE REQUIREMENT	572,888	341,319	22,564	109,656	41,814	43,196	14,339
14	BILLING UNITS (ANNUAL)							
15	ENERGY (MWH)		5,264,445	291,283	2,733,687	1,233,654	1,477,619	153,590
16	BILLING DEMAND (KW)		-	-	8,569,894	2,539,002	687,068	-
17	SBS BILLING KW FOR RSRV CHG		-	-	-	-	89,448	-
18	CUSTOMER		4,632,396	349,672	209,964	3,408	816	123,744
19	UNIT COST							
20	ENERGY (¢/KWH)		0.48421	0.47995	0.48535	0.47801	0.46182	0.48245
21	CUSTOMER($/CUST/MO OR ¢/KWH)		20.88	29.29	45.20	269.37	840.69	10.13
22	CUSTOMER(LIGHTING FACIL.)							
23	($/CUSTOMER/MO)		-	-	-	-	-	79.51
24	DEMAND - PRODUCTION - $/KW		-	-	5.45	7.81	8.68 [1]	-
25	DEMAND - TRANSMISSION - $/KW		-	-	1.57	2.23	2.37 [1]	-
26	DEMAND - DISTRIBUTION - $/KW		-	-	3.12	3.74	0.50 [1]	-
27	DEMAND - PRODUCTION - ¢/KWH		2.26389	1.98707	1.70769	1.60702	1.63459	0.57947
28	DEMAND - TRANSMISSION - ¢/KWH		0.65411	0.57710	0.49362	0.45993	0.45100	0.16993
29	DEMAND - DISTRIBUTION - ¢/KWH		1.24406	1.18476	0.97747	0.77007	0.32952	0.68157
30	1 $/KW Based on Rate Class SBS							

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: For each cost of service study filed by the company, calculate the unit costs for demand, energy and customer for each rate schedule at proposed rates, based on the revenue requirements from sales of electricity only, excluding other operating revenues. The demand unit costs must be separated into production, transmission and distribution. Unit costs under proposed rates must be calculated at the system rate of return. Unit costs must be provided separately for each existing rate class, except for the lighting classes. If the company is proposing to combine two or more classes, it must also provide unit costs for the classes combined. Customer unit costs for the lighting classes must include only customer-related costs, excluding costs for fixtures and poles. The lighting fixtures and poles must be shown on a separate line. Billing units must match Schedule E-5.

Type of Data Shown:
X Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
___ Historical Year Ended 12/31/12
Witness: M. T. O'Sheasy

($000s)

SYSTEM (EQUAL) RATE OF RETURN

Allocation Method: 12MCP - 1/13th kWh

(1) LINE NO.	(2) DESCRIPTION	(3) TOTAL RETAIL SERVICE	(4) RATE CLASS RESIDENTIAL	(5) RATE CLASS GS	(6) RATE CLASS GSD/GSDT	(7) RATE CLASS LP/LPT	(8) RATE CLASS MAJOR ACCTS	(9) RATE CLASS OS
1	REVENUE REQUIREMENTS FROM							
2	SALE OF ELECTRICITY ($000)							
3	ENERGY (NON-FUEL PORTION)	53,626	25,503	1,399	13,264	5,896	6,823	741
4	DEMAND	421,140	237,834	11,935	94,583	37,457	36,346	2,985
5	PRODUCTION	216,545	119,226	5,796	46,658	19,822	24,151	892
6	TRANSMISSION	62,222	34,447	1,681	13,493	5,673	6,664	264
7	DISTRIBUTION	142,373	84,161	4,458	34,432	11,962	5,531	1,829
6	CUSTOMER	98,130	69,783	8,230	8,180	872	681	10,384
9	DISTRIBUTION	29,877	24,756	2,479	2,443	112	54	33
10	CUSTOMER ACCOUNTS	31,909	27,759	2,236	1,332	36	61	485
11	CUSTOMER ASSISTANCE	26,478	17,268	3,515	4,405	724	566	0
12	CUSTOMER (LIGHTING FACIL)	9,866	0	0	0	0	0	9,866
13	TOTAL REVENUE REQUIREMENT	572,896	333,120	21,564	116,027	44,225	43,850	14,110
14	BILLING UNITS (ANNUAL)							
15	ENERGY (MWH)		5,264,445	291,283	2,733,687	1,233,654	1,477,619	153,590
16	BILLING DEMAND (KW)		-	-	8,569,894	2,539,002	887,068	-
17	SBS BILLING KW FOR RSRV CHG		-	-	-	-	89,448	-
18	CUSTOMER		4,632,396	349,872	209,964	3,408	816	123,744
19	UNIT COST							
20	ENERGY (¢/KWH)		0.48444	0.48029	0.48521	0.47793	0.46176	0.48245
21	CUSTOMER($/CUST/MO OR ¢/KWH)		15.08	23.52	38.96	255.87	834.56	4.19
22	CUSTOMER(LIGHTING FACIL.)							
23	($/CUSTOMER/MO)		-	-	-	-	-	79.73
24	DEMAND - PRODUCTION - $/KW		-	-	5.44	7.81	8.88 [1]	-
25	DEMAND - TRANSMISSION - $/KW		-	-	1.57	2.23	2.37 [1]	-
26	DEMAND - DISTRIBUTION - $/KW		-	-	4.02	4.71	0.50 [1]	-
27	DEMAND - PRODUCTION - ¢/KWH		2.26474	1.98982	1.70678	1.60677	1.63445	0.58077
28	DEMAND - TRANSMISSION - ¢/KWH		0.65433	0.57710	0.49358	0.45985	0.45100	0.17189
29	DEMAND - DISTRIBUTION - ¢/KWH		1.59867	1.53047	1.25954	0.96964	0.37432	1.19063
30	1 $/KW Based on Rate Class SBS							

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO. : 130140-EI

EXPLANATION: Provide the calculation of the current cost of providing the services listed in Schedule E-13b. At a minimum, the schedule must include an estimate of all labor, transportation, customer accounting and overhead costs incurred in providing the service, and a short narrative describing the tasks performed.

Type of Data Shown:
_X_ Projected Test Year Ended 12/31/14
_____ Prior Year Ended 12/31/13
_____ Historical Year Ended 12/31/12
Witness: M. D. Neyman

Connection of Initial Service - Residential

(1) Line No.	(2) Task	(3) Costs Connect	(4) Costs Disconnect	(5) Costs Total	(6) Cost Description
1					
2	The Customer Care Representative in the				
3	Customer Care Center receives and				
4	processes request from customer.	$ 19.87	$ 7.14	$ 27.01	This cost represents labor and benefits, communication equipment, office expenses, incidental expenses, materials, Information Technology (IT) products and services, customer accounting, and overheads.
5	The Service Dispatcher in the Dispatch				
6	Center dispatches the order to the				
7	appropriate field representative and				
8	completes the order after the field work has				
9	been performed.	$ 0.59	$ 0.59	$ 1.18	This cost represents labor and benefits, communication equipment, office expenses, incidental expenses, IT products and services, and Automated Resource Management System (ARMS) wireless laptop leases.
10					
11	The Field Service Representative				
12	disconnects the service.	$ -	$ 0.65	$ 0.65	This cost represents labor and benefits, communication equipment, office expenses, meals, transportation, incidental expenses, and ARMS wireless laptop leases.
13					
14					
15	The Service Technician connects the service.	$ 8.56	$ 0.00	$ 8.56	This cost represents the carrying cost for the activity performed by the Service Technician, which is only capitalized for the connection of initial service.
16	Total	$ 29.02	$ 8.38	$ 37.40	

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO. : 130140-EI

EXPLANATION: Provide the calculation of the current cost of providing the services listed in Schedule E-13b. At a minimum, the schedule must include an estimate of all labor, transportation, customer accounting and overhead costs incurred in providing the service, and a short narrative describing the tasks performed.

Type of Data Shown:
_X_ Projected Test Year Ended 12/31/14
_____ Prior Year Ended 12/31/13
_____ Historical Year Ended 12/31/12
Witness: M. D. Neyman

Connection of Initial Service - Non Residential

(1) Line No.	(2) Task	(3) Costs Connect	(4) Costs Disconnect	(5) Costs Total	(6) Cost Description
1					
2	The Customer Care Representative in the				This cost represents labor and benefits, communication
3	Customer Care Center receives and				equipment, office expenses, incidental expenses, materials,
4	processes request from customer.	$ 19.87	$ 7.14	$ 27.01	Information Technology (IT) products and services, customer accounting, and overheads.
5	The Service Dispatcher in the Dispatch				
6	Center dispatches the order to the				This cost represents labor and benefits, communication
7	appropriate field representative and				equipment, office expenses, incidental expenses, IT
8	completes the order after the field work has				products and services, and Automated Resource
9	been performed.	$ 4.29	$ 4.29	$ 8.58	Management System (ARMS) wireless laptop leases.
10					
11	The Field Service Representative				This cost represents labor and benefits, communication
12	disconnects the service.	$ -	$ 32.25	$ 32.25	equipment, office expenses, meals, transportation, incidental expenses, and ARMS wireless laptop leases.
13					
14					This cost represents the carrying cost for the activity
15	The Service Technician connects the service.	$ 8.56	$ 0.00	$ 8.56	performed by the Service Technician, which is only capitalized for the connection of initial service.
16	Total	$ 32.72	$ 43.68	$ 76.40	

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide the calculation of the current cost of providing the services listed in Schedule E-13b. At a minimum, the schedule must include an estimate of all labor, transportation, customer accounting and overhead costs incurred in providing the service, and a short narrative describing the tasks performed.

Type of Data Shown:
X Projected Test Year Ended 12/31/14
_____ Prior Year Ended 12/31/13
_____ Historical Year Ended 12/31/12
Witness: M. D. Neyman

Connection of Existing Service - Residential

(1) Line No.	(2) Task	(3) Costs Connect	(4) Costs Disconnect	(5) Costs Total	(6) Cost Description
1					
2	The Customer Care Representative in the				This cost represents labor and benefits, communication
3	Customer Care Center receives and				equipment, office expenses, incidental expenses, materials,
4	processes request from customer.	$ 19.87	$ 7.14	$ 27.01	Information Technology (IT) products and services, customer accounting, and overheads.
5	The Service Dispatcher in the Dispatch				
6	Center dispatches the order to the				This cost represents labor and benefits, communication
7	appropriate field representative and				equipment, office expenses, incidental expenses, IT
8	completes the order after the field work has				products and services, and Automated Resource
9	been performed.	$ 0.59	$ 0.59	$ 1.18	Management System (ARMS) wireless laptop leases.
10					
11	The Field Service Representative connects				This cost represents labor and benefits, communication
12	and disconnects the service.	$ 0.65	$ 0.65	$ 1.30	equipment, office expenses, meals, transportation, incidental expenses, and ARMS wireless laptop leases.
13	Total	$ 21.11	$ 8.38	$ 29.49	

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO. : 130140-EI

EXPLANATION: Provide the calculation of the current cost of providing the services listed in Schedule E-13b. At a minimum, the schedule must include an estimate of all labor, transportation, customer accounting and overhead costs incurred in providing the service, and a short narrative describing the tasks performed.

Type of Data Shown:
X Projected Test Year Ended 12/31/14
_____ Prior Year Ended 12/31/13
_____ Historical Year Ended 12/31/12
Witness: M. D. Neyman

Connection of Existing Service - Non Residential

(1) Line No.	(2) Task	(3) Costs Connect	(4) Costs Disconnect	(5) Costs Total	(6) Cost Description
1					
2	The Customer Care Representative in the				This cost represents labor and benefits, communication
3	Customer Care Center receives and				equipment, office expenses, incidental expenses, materials,
4	processes request from customer.	$ 19.87	$ 7.14	$ 27.01	Information Technology (IT) products and services, customer accounting, and overheads.
5	The Service Dispatcher in the Dispatch				
6	Center dispatches the order to the				This cost represents labor and benefits, communication
7	appropriate field representative and				equipment, office expenses, incidental expenses, IT
8	completes the order after the field work has				products and services, and Automated Resource
9	been performed.	$ 4.29	$ 4.29	$ 8.58	Management System (ARMS) wireless laptop leases.
10					
11	The Field Service Representative connects				This cost represents labor and benefits, communication
12	and disconnects the service.	$ 40.31	$ 32.25	$ 72.56	equipment, office expenses, meals, transportation, incidental expenses, and ARMS wireless laptop leases.
13	Total	$ 64.47	$ 43.68	$ 108.15	

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO. : 130140-EI

EXPLANATION: Provide the calculation of the current cost of providing the services listed in Schedule E-13b. At a minimum, the schedule must include an estimate of all labor, transportation, customer accounting and overhead costs incurred in providing the service, and a short narrative describing the tasks performed.

Type of Data Shown:
_X_ Projected Test Year Ended 12/31/14
_____ Prior Year Ended 12/31/13
_____ Historical Year Ended 12/31/12
Witness: M. D. Neyman

Restoration of Service (After Violation of Rules)

(1) Line No.	(2) Task	(3) Costs Disconnect	(4) Costs Restore	(5) Costs Total	(6) Cost Description
1					
2	The Customer Care Representative in the				This cost represents labor and benefits, communication
3	Customer Care Center receives and				equipment, office expenses, incidental expenses, materials,
4	processes request from customer.	$ -	$ 4.62	$ 4.62	Information Technology (IT) products and services, customer accounting, and overheads.
5	The Customer Service Representive				This cost represents labor and benefits, communication
6	performs collection services for customers in				equipment, office expenses, incidental expenses, materials,
7	the office, such as payment arrangements,				IT products and services, customer accounting, and
8	extensions, collections, etc.	$ -	$ 4.94	$ 4.94	overheads.
9	The Service Dispatcher in the Dispatch				
10	Center dispatches the order to the				This cost represents labor and benefits, communication
11	appropriate field representative and				equipment, office expenses, incidental expenses, IT
12	completes the order after the field work has				products and services, and Automated Resource
13	been performed.	$ 4.29	$ 4.29	$ 8.58	Management System (ARMS) wireless laptop leases.
14					
15	The Customer Service Representive builds				This cost represents labor and benefits, communication
16	collection lists and evaluates the accounts				equipment, office expenses, incidental expenses, materials,
17	prior to sending to the field for action.	$ 1.82	$ 0.00	$ 1.82	IT products and services, customer accounting, and overheads.
18					
19	The Field Service Representative				This cost represents labor and benefits, communication
20	disconnects and restores the service.	$ 22.42	$ 22.42	$ 44.84	equipment, office expenses, meals, transportation, incidental expenses, and ARMS wireless laptop leases.
21	Total	$ 28.53	$ 36.27	$ 64.80	

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO. : 130140-EI

EXPLANATION: Provide the calculation of the current cost of providing the services listed in Schedule E-13b. At a minimum, the schedule must include an estimate of all labor, transportation, customer accounting and overhead costs incurred in providing the service, and a short narrative describing the tasks performed.

Type of Data Shown:
X Projected Test Year Ended 12/31/14
_____ Prior Year Ended 12/31/13
_____ Historical Year Ended 12/31/12
Witness: M. D. Neyman

Restoration of Service After Hours (After Violation of Rules)

(1) Line No.	(2) Task	(3) Costs Disconnect	(4) Costs Restore after hours (6:00 p.m.)	(5) Costs Total	(6) Cost Description
1					This cost represents labor and benefits, communication equipment, office expenses, incidental expenses, materials, Information Technology (IT) products and services, customer accounting, and overheads.
2	The Customer Care Representative in the				
3	Customer Care Center receives and				
4	processes request from customer.	$ -	$ 4.62	$ 4.62	
5	The Customer Service Representive				This cost represents labor and benefits, communication equipment, office expenses, incidental expenses, materials, IT products and services, customer accounting, and overheads.
6	performs collection services for customers in				
7	the office, such as payment arrangements,				
8	extensions, collections, etc.	$ 4.94	$ 4.94	$ 9.88	
9	The Service Dispatcher in the Dispatch				This cost represents labor and benefits, communication equipment, office expenses, incidental expenses, IT products and services, and Automated Resource Management System (ARMS) wireless laptop leases.
10	Center dispatches the order to the				
11	appropriate field representative and				
12	completes the order after the field work has				
13	been performed.	$ 4.29	$ 4.29	$ 8.58	
14					This cost represents labor and benefits, communication equipment, office expenses, incidental expenses, materials, IT products and services, customer accounting, and overheads.
15	The Customer Service Representive builds				
16	collection lists and evaluates the accounts				
17	prior to sending to the field for action.	$ 1.82	$ 0.00	$ 1.82	
18					This cost represents labor and benefits, communication equipment, office expenses, meals, transportation, Incidental expenses, and ARMS wireless laptop leases.
19	The Field Service Representative				
20	disconnects the service.	$ 22.42	$ 0.00	$ 22.42	
21					This cost represents labor and benefits, communication equipment, meals, transportation, ARMS wireless and laptop leases, miscellaneous expenses, small tools, and minor materials.
22					
23	After 6:00 p.m, the Service Technician is				
24	required to restore the service.	$ -	$ 28.70	$ 28.70	
25	Total	$ 33.47	$ 42.55	$ 76.02	

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO. : 130140-EI

EXPLANATION: Provide the calculation of the current cost of providing the services listed in Schedule E-13b. At a minimum, the schedule must include an estimate of all labor, transportation, customer accounting and overhead costs incurred in providing the service, and a short narrative service describing the tasks performed.

Type of Data Shown:
_X_ Projected Test Year Ended 12/31/14
_____ Prior Year Ended 12/31/13
_____ Historical Year Ended 12/31/12
Witness: M. D. Neyman

Restoration of Service at Pole (After Violation of Rules)

(1) Line No.	(2) Task	(3) Costs Disconnect at Pole	(4) Costs Restore at Pole	(5) Costs Total	(6) Cost Description
1					
2	The Customer Care Representative in the				This cost represents labor and benefits, communication
3	Customer Care Center receives and processes				equipment, office expenses, incidental expenses, materials,
4	request from customer.	$ -	$ 4.62	$ 4.62	Information Technology (IT) products and services, customer accounting, and overheads.
5	The Customer Service Representive performs				This cost represents labor and benefits, communication
6	collection services for customers in the office,				equipment, office expenses, incidental expenses, materials,
7	such as payment arrangements, extensions,				IT products and services, customer accounting, and
8	collections, etc.	$ -	$ 4.94	$ 4.94	overheads.
9	The Service Dispatcher in the Dispatch Center				This cost represents labor and benefits, communication
10	dispatches the order to the appropriate field				equipment, office expenses, incidental expenses, IT
11	representative and completes the order after the				products and services, and Automated Resource
12	field work has been performed.	$ 4.29	$ 4.29	$ 8.58	Management System (ARMS) wireless laptop leases.
13					
14	The Customer Service Representive builds				This cost represents labor and benefits, communication
15	collection lists and evaluates the accounts prior to				equipment, office expenses, incidental expenses, materials,
16	sending to the field for action.	$ 1.82	$ -	$ 1.82	IT products and services, customer accounting, and overheads.
17	Fifty percent of the time, the Field Service				
18	Representative travels to the premise and finds				
19	the meter inaccessible. The Service Technician				This cost represents labor and benefits, communication
20	is then required to make an additional trip to the				equipment, office expenses, meals, transportation,
21	premise to disconnect service at the pole.	$ 11.21	$ -	$ 11.21	incidental expenses, and ARMS wireless laptop leases.
22					
23	The Service Technician returns to the premise to				This cost represents labor and benefits, communication
24	disconnect the service after the Field Service				equipment, meals, transportation, ARMS wireless laptop
25	Representative finds the meter inaccessible.	$ 29.40	$ -	$ 29.40	leases, miscellaneous expenses, small tools, and minor materials.
26					
27					This cost represents labor and benefits, communication
28	The Service Technician restores the service at the				equipment, meals, transportation, ARMS wireless laptop
29	pole.	$ -	$ 33.60	$ 33.60	leases, miscellaneous expenses, small tools, and minor materials.
30	Total	$ 46.72	$ 47.45	$ 94.17	

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO. : 130140-EI

EXPLANATION: Provide the calculation of the current cost of providing the services listed in Schedule E-13b. At a minimum, the schedule must include an estimate of all labor, transportation, customer accounting and overhead costs incurred in providing the service, and a short narrative describing the tasks performed.

Type of Data Shown:
_X_ Projected Test Year Ended 12/31/14
_____ Prior Year Ended 12/31/13
_____ Historical Year Ended 12/31/12
Witness: M. D. Neyman

Premise Visit

(1) Line No.	(2) Task	(3) Costs	(4) Cost Description
1	The Customer Service Representive		This cost represents labor and benefits, communication
2	performs collection services for customers		equipment, office expenses, incidental expenses,
3	in the office, such as payment		materials, Information Technology (IT) products and
4	arrangements, extensions, collections, etc.	$ 4.94	services, customer accounting, and overheads.
5	The Service Dispatcher in the Dispatch		
6	Center dispatches the order to the		This cost represents labor and benefits, communication
7	appropriate field representative and		equipment, office expenses, incidental expenses, IT
8	completes the order after the field work has		products and services, and Automated Resource
9	been performed.	$ 4.29	Management System (ARMS) wireless laptop leases.
10			
11	The Customer Service Representive builds		This cost represents labor and benefits, communication
12	collection lists and evaluates the accounts		equipment, office expenses, incidental expenses,
13	prior to sending to the field for action.	$ 1.82	materials, IT products and services, customer accounting, and overheads.
14	The Field Service Representative visits the		This cost represents labor and benefits, communication
15	premise and leaves notification of		equipment, office expenses, meals, transportation,
16	delinquency.	$ 22.42	incidental expenses, and ARMS wireless laptop leases.
17	Total	$ 33.47	

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO. : 130140-EI

EXPLANATION: Provide the calculation of the current cost of providing the services listed in Schedule E-13b. At a minimum, the schedule must include an estimate of all labor, transportation, customer accounting and overhead costs incurred in providing the service, and a short narrative service describing the tasks performed.

Type of Data Shown:
_X_ Projected Test Year Ended 12/31/14
_____ Prior Year Ended 12/31/13
_____ Historical Year Ended 12/31/12
Witness: M. D. Neyman

Connection of Temporary Service

(1) Line No.	(2) Task	(3) Costs Connect	(4) Costs Disconnect	(5) Costs Total	(6) Cost Description
1					
2	The Customer Care Representative in the				This cost represents labor and benefits, communication
3	Customer Care Center receives and				equipment, office expenses, incidental expenses, materials,
4	processes request from customer.	$ 19.87	$ 7.14	$ 27.01	Information Technology (IT) products and services, customer accounting, and overheads.
5	The Service Dispatcher in the Dispatch				
6	Center dispatches the order to the				This cost represents labor and benefits, communication
7	appropriate field representative and				equipment, office expenses, incidental expenses, IT
8	completes the order after the field work				products and services, and Automated Resource
9	has been performed.	$ 4.29	$ 4.29	$ 8.58	Management System (ARMS) wireless laptop leases.
10					
11					This cost represents labor and benefits, communication
12	The Service Technician connects the				equipment, meals, transportation, ARMS wireless and
13	service.	$ 51.80	$ 32.90	$ 84.70	laptop leases, miscellaneous expenses, small tools, and minor materials.
14	Total	$ 75.96	$ 44.33	$ 120.29	

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO. : 130140-EI

EXPLANATION: Provide the calculation of the current cost of providing the services listed in Schedule E-13b. At a minimum, the schedule must include an estimate of all labor, transportation, customer accounting and overhead costs incurred in providing the service, and a short narrative describing the tasks performed.

Type of Data Shown:
_X_ Projected Test Year Ended 12/31/14
_____ Prior Year Ended 12/31/13
_____ Historical Year Ended 12/31/12
Witness: M. D. Neyman

Investigation of Unauthorized Use - FSR

(1) Line No.	(2) Task	(3) Costs	(4) Cost Description
1	The Field Service Representative opens a		
2	revenue protection case and performs all		This cost represents labor and benefits, communication
3	investigative activities until the case is closed		equipment, office expenses, incidental expenses, materials,
4	or until the case is turned over to a Security		Information Technology (IT) products and services,
5	Dept Investigator to complete the case.	$ 70.83	customer accounting, and overheads.
6	Total	$ 70.83	

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO. : 130140-EI

EXPLANATION: Provide the calculation of the current cost of providing the services listed in Schedule E-13b. At a minimum, the schedule must include an estimate of all labor, transportation, customer accounting and overhead costs incurred in providing the service, and a short narrative describing the tasks performed.

Type of Data Shown:
__X__Projected Test Year Ended 12/31/14
_____Prior Year Ended 12/31/13
_____Historical Year Ended 12/31/12
Witness: M. D. Neyman

Line No.	(1) Task	(2) Returned Item Charge (3) Costs
1	Returned Item Charge for Amounts > $300	$ 40.00
2	Returned Item Charge for Amounts > $50 < $300	$ 30.00
3	Returned Item Charge for Amounts < $50	$ 25.00

4 Note: The returned item fee is based on the amount of the returned check or draft dishonored by the bank, in accordance with Florida Statute 68.065.

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide a schedule which shows the company-proposed increase in revenue by rate schedule and the present and company-proposed class rates of return under the proposed cost of service study. Provide justification for every class not left at the system rate of return. If the increase from service charges by rate class does not equal that shown on Schedule E-13b or if the increase from sales of electricity does not equal that shown on Schedule E-13a, provide an explanation.

Type of Data Shown:
_X_ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
___ Historical Year Ended 12/31/12
Witness: J. I. Thompson

Allocation Method: 12MCP - 1/13th kWh - Minimum Distribution System

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
		Present		Increase	Increase	Increase		Company Proposed		% Increase	
Line No.	Rate Class	ROR	Index	from Service Charges	from Sale of Electricity	from Other Revenue - Unbilled	Total Increase	ROR	Index	With Adjustment Clauses	Without Adjustment Clauses
1	RESIDENTIAL	3.98%	0.96	$972,075	$43,270,746	$60,179	$44,303,000	6.46%	1.00	6.70%	14.92%
2	GS	4.52%	1.12	$117,224	$2,252,390	$2,386	$2,372,000	6.80%	1.05	6.03%	11.55%
3	GSD/GSDT	5.37%	1.33	$55,767	$13,124,695	$13,538	$13,194,000	7.48%	1.16	4.71%	12.84%
4	LP/LPT	3.24%	0.80	$0	$7,090,731	$13,269	$7,104,000	6.15%	0.95	6.06%	20.94%
5	MAJOR ACCTS	0.84%	0.21	$0	$6,570,000	$0	$6,570,000	3.53%	0.55	4.79%	22.31%
6	OS	7.17%	1.77	$0	$849,106	$894	$850,000	8.23%	1.27	3.28%	5.71%
7	TOTAL RETAIL:	4.05%	1.00	$1,145,066	$73,157,668	$90,266	$74,393,000	6.47%	1.00	5.90%	14.92%

Supporting Schedules: E-13a, E-13b

Recap Schedules:

Schedule E-8 COMPANY-PROPOSED ALLOCATION OF THE RATE INCREASE BY RATE CLASS

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide a schedule which shows the company-proposed increase in revenue by rate schedule and the present and company-proposed class rates of return under the proposed cost of service study. Provide justification for every class not left at the system rate of return. If the increase from service charges by rate class does not equal that shown on Schedule E-13b or if the increase from sales of electricity does not equal that shown on Schedule E-13a, provide an explanation.

Type of Data Shown:
_X_ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
___ Historical Year Ended 12/31/12
Witness: J. I. Thompson

Allocation Method: 12MCP - 1/13th kWh

(1) Line No.	(2) Rate Class	(3) Present ROR	(4) Present Index	(5) Increase from Service Charges	(6) Increase from Sale of Electricity	(7) Increase from Other Revenue - Unbilled	(8) Total Increase	(9) Company Proposed ROR	(10) Company Proposed Index	(11) % Increase With Adjustment Clauses	(12) % Increase Without Adjustment Clauses
1	RESIDENTIAL	4.38%	1.08	$972,075	$43,270,746	$60,179	$44,303,000	6.94%	1.07	6.70%	14.92%
2	GS	5.43%	1.34	$117,224	$2,252,390	$2,386	$2,372,000	7.84%	1.21	6.03%	11.55%
3	GSD/GSDT	4.47%	1.10	$55,767	$13,124,695	$13,538	$13,194,000	6.46%	1.00	4.71%	12.84%
4	LP/LPT	2.48%	0.61	$0	$7,090,731	$13,269	$7,104,000	5.24%	0.81	6.06%	20.94%
5	MAJOR ACCTS	0.66%	0.16	$0	$6,570,000	$0	$6,570,000	3.31%	0.51	4.79%	22.31%
6	OS	7.48%	1.85	$0	$849,106	$894	$850,000	8.56%	1.32	3.28%	5.71%
7	TOTAL RETAIL:	4.05%	1.00	$1,145,066	$73,157,668	$90,266	$74,393,000	6.47%	1.00	5.90%	14.92%

Supporting Schedules: E-13a, E-13b

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide the load data below by rate schedule. Any other load data used to develop demand allocation factors for cost of service studies submitted must also be provided. The average number of customers and annual MWH should be in agreement with the company's forecast in Schedule E-15.

Type of Data Shown:
X Projected Test Year Ended 12/31/14
__ Prior Year Ended 12/31/13
__ Historical Year Ended 12/31/12
Witness: M. T. O'Sheasy, J. I. Thompson

Allocation Method: 12MCP - 1/13th kWh - Minimum Distribution System

(1) LINE NO.	(2) RATE SCHEDULE	(3) ANNUAL SALES MWH	(4) UNBILLED MWH	(5) TOTAL SALES MWH	(6) OUTPUT TO LINE MWH*	(7) CLASS NCP KW*	(8) CP WINTER KW*	(9) CP SUMMER KW*	(10) AVERAGE 12 CP KW*	(11) AVERAGE DEMAND KW*	(12) 12 CP & 1/13 WTD AVG DMD	(13) AVG NUMBER OF CUSTOMERS
1	RATE CLASS RESIDENTIAL	5,258,938	5,507	5,264,445	5,643,768	1,484,221	1,416,102	1,313,739	1,144,164	644,266	1,105,710	386,033
2	RATE CLASS GS	290,975	308	291,283	312,270	80,213	56,977	72,089	55,758	35,647	54,211	29,156
3	RATE CLASS GSD/GSDT	2,730,850	2,837	2,733,687	2,930,180	620,485	371,571	583,449	451,028	334,495	442,064	17,497
4	RATE CLSS LP/LPT	1,231,342	2,312	1,233,654	1,304,356	225,191	159,767	234,281	191,920	148,899	188,611	284
5	MAJOR ACCOUNTS	1,477,619	0	1,477,619	1,508,184	95,735	222,173	242,902	233,603	172,167	228,877	68
6	RATE CLASS OS	153,368	222	153,590	164,657	38,108	13,175	4,949	8,774	18,796	9,545	10,312
7	SUBTOTAL RETAIL	11,143,092	11,186	11,154,278	11,863,415	2,543,953	2,239,765	2,451,409	2,085,247	1,354,270	2,029,018	443,350
8	WHOLESALE	351,048	0	351,048	356,397	0	78,236	70,590	64,086	40,685	N/A	1
9	TOTAL	11,494,140	11,186	11,505,326	12,219,812	2,543,953	2,318,001	2,521,999	2,149,333	1,394,955	2,029,018	443,351

10 * At Generation

Supporting Schedules: Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide the load data below by rate schedule. Any other load data used to develop demand allocation factors for cost of service studies submitted must also be provided. The average number of customers and annual MWH should be in agreement with the company's forecast in Schedule E-15.

Type of Data Shown:
X Projected Test Year Ended 12/31/14
_ Prior Year Ended 12/31/13
_ Historical Year Ended 12/31/12
Witness: M. T. O'Sheasy, J. I. Thompson

Allocation Method: 12MCP - 1/13th kWh

(1) LINE NO.	(2) RATE SCHEDULE	(3) ANNUAL SALES MWH	(4) UNBILLED MWH	(5) TOTAL SALES MWH	(6) OUTPUT TO LINE MWH*	(7) CLASS NCP KW*	(8) CP WINTER KW*	(9) CP SUMMER KW*	(10) AVERAGE 12 CP KW*	(11) AVERAGE DEMAND KW*	(12) 12 CP & 1/13 WTD AVG DMD	(13) AVG NUMBER OF CUSTOMERS
1	RATE CLASS RESIDENTIAL	5,258,938	5,507	5,264,445	5,643,768	1,484,223	1,416,102	1,313,739	1,144,164	644,266	1,105,710	386,033
2	RATE CLASS GS	290,975	308	291,283	312,270	80,213	56,977	72,089	55,758	35,647	54,211	29,156
3	RATE CLASS GSD/GSDT	2,730,850	2,837	2,733,687	2,930,180	620,484	371,571	583,449	451,028	334,495	442,064	17,497
4	RATE CLSS LP/LPT	1,231,342	2,312	1,233,654	1,304,356	225,191	159,767	234,281	191,920	148,899	188,611	284
5	MAJOR ACCOUNTS	1,477,619	0	1,477,619	1,508,184	95,735	222,173	242,902	233,603	172,167	228,877	68
6	RATE CLASS OS	153,368	222	153,590	164,657	38,109	13,175	4,949	8,774	18,796	9,545	10,312
7	SUBTOTAL RETAIL	11,143,092	11,186	11,154,278	11,863,415	2,543,955	2,239,765	2,451,409	2,085,247	1,354,270	2,029,018	443,350
8	WHOLESALE	351,048	0	351,048	356,397	0	78,236	70,590	64,086	40,685	N/A	1
9	TOTAL	11,494,140	11,186	11,505,326	12,219,812	2,543,955	2,318,001	2,521,999	2,149,333	1,394,955	2,029,018	443,351

10 * At Generation

50

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Derive each allocation factor used in the cost of service studies. Provide supporting data and any workpapers used in deriving the allocation factors, and a brief narrative description of the development of each allocation factor.

Type of Data Shown:
X Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
___ Historical Year Ended 12/31/12
___ Witness: M. T. O'Sheasy

Allocation Method:12MCP - 1/13th kWh - Minimum Distribution Method

Line No.

1 Demand Related

METHODOLOGY FOR DEVELOPING ALLOCATION FACTORS

2 Demand Allocators are developed for each respective level. Level 1 and 2 are identical, since Gulf does not make any sales at Level 1. This allocator and the Level 3
3 demand allocator are calculated by the 12-MCP method. Levels 4 and 5 are based on the annual non-coincident peak demands for each respective rate class.

4 The numeric designations refer to the following voltage levels:

5	Level	Description	Voltage
6	1	Production	
7	2	Transmission Step-Up Substations	
8		Transmission Lines	115/230
9		Transmission Substations maintaining	115/230 to 46
10		integrity of the transmission grid	
11		Subtransmission Lines	46
12	3	Transmission and Distribution Substations	115/230 to 12
13		making a transformation from Transmission	and 46 to 12
14		voltage to Distribution voltage	and lower
15	4	Primary Distribution Lines	Less than 22
16	5	Secondary Distribution (line transformers)	

17 Production level costs are allocated first to jurisdiction on a Level 1 12-MCP allocator. The retail jurisdiction resultant is then divided into two pieces:
18 one piece which is 12/13 of the retail portion is then allocated back to retail rates upon the appropriate Level 1 12-MCP allocator, while the remaining piece,
19 which is the 1/13 of the retail portion, is then allocated back to retail rates upon the appropriate Level 1 Energy Allocator.

20 Mr. Thompson provides the 12-MCP demand for each rate class by level and also provides the total system losses. The load flow process, as described in
21 Mr. O'Sheasy's testimony, internally calculates the 12-MCP demand allocators by rate and level adjusted for losses.

Supporting Schedules: Recap Schedules: E-16

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Derive each allocation factor used in the cost of service studies. Provide supporting data and any workpapers used in deriving the allocation factors, and a brief narrative description of the development of each allocation factor.

Type of Data Shown:
X Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
___ Historical Year Ended 12/31/12
___ Witness: M. T. O'Sheasy

Allocation Method:12MCP - 1/13th kWh - Minimum Distribution Method

Line No.

1 METHODOLOGY FOR DEVELOPING ALLOCATION FACTORS

2 Demand levels 4 and 5 are allocated on the annual non-coincident peak demand (NCP). The NCP demands are provided by Mr. Thompson, and the loss factors
3 developed in the 12-MCP load balance are used to adjust for losses. Workpapers for all the demand and energy allocators are attached.

4 Energy Related

5 Mr. O'Sheasy's testimony describes the development of the energy allocator. Related workpapers are attac

6 Customer Related

7 Mr. Thompson provided the average number of customers by rate and level for the test period. These allocators are summarized in Sched

8 The customer accounts expense was directly assigned to rate, provided by Gulf Power Company. Uncollectible expense was directly assigned to rate, provided by Gulf Power Company.

9 Gulf Power Company provided a breakdown of each customer assistance expense account. The analysis of these accounts to rate is detailed
10 in Exhibit_____MTO-2.

11 Accounts 364 - 370 were classified as customer and demand related using the Minimum Distribution System as explained in Mr. O'Sheasy's testimony.

12 Account 370 was classified as customer related and was allocated to rate according to the following analysis: Single phase watthour meters were allocated
13 between RS, GS, and GSD based on the number of meters installed. All other single phase meters were assigned to GSD. Three phase
14 watthour meters were allocated to RS, GS, and GSD based on the number of meters installed. Three phase demand meters were allocated to GS
15 and GSD based on the number of metered customers. Accessory equipment was allocated to all rate classes based on the number of
16 meters installed. AMI single phase meters were allocated to RS, GS, GSD and OS based on number of single phase meters installed and AMI three phase meters were
17 allocated to RS, GS, GSD, LP, Major Accounts, and OS based on number of three phase meters installed.

18 Other Related

19 Salaries and Wages were provided by function for the test period. The production portion was allocated to jurisdiction upon 12-MCP. The retail portion was then
20 allocated to retail rates upon the 12-MCP and 1/13 energy methodology mentioned above under demand. The other functional amounts were allocated to rate on the
21 corresponding operation and maintenance expenses. The functional split and results are summarized in Exhibit_____MTO-2.

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Derive each allocation factor used in the cost of service studies. Provide supporting data and any workpapers used in deriving the allocation factors, and a brief narrative description of the development of each allocation factor.

Type of Data Shown:
X Projected Test Year Ended 12/31/14
__ Prior Year Ended 12/31/13
__ Historical Year Ended 12/31/12
__ Witness: M. T. O'Sheasy

Allocation Method:12MCP - 1/13th kWh - Minimum Distribution Method

12/13 DEMAND ALLOCATION
AVERAGE NUMBER OF CUSTOMERS

(1) LINE NO.	(2) DESCRIPTION LEVEL	(3) TOTAL ELECTRIC SYSTEM	(4) RATE CLASS RESIDENTIAL	(5) RATE CLASS GS	(6) RATE CLASS GSD/GSDT	(7) RATE CLASS LP/LPT	(8) RATE CLASS MAJOR ACCTS	(9) RATE CLASS OS	(10) TOTAL RETAIL SERVICE	(11) WHOLESALE
1										
2	A	0	0	0	0	0	0	0	0	0
3	B-1	0	0	0	0	0	0	0	0	0
4	B-2	3	0	0	0	0	3	0	3	0
5	C-1 CUSTOMER SUBS	0	0	0	0	0	0	0	0	0
6	C-1 COMMON	0	0	0	0	0	0	0	0	0
7	TOTAL C-1	0	0	0	0	0	0	0	0	0
8	C-2 CUSTOMER SUBS	11	0	0	0	4	6	0	10	1
9	C-2 COMMON	7	0	0	0	1	6	0	7	0
10	TOTAL C-2	18	0	0	0	5	12	0	17	1
11	D	0	0	0	0	0	0	0	0	0
12	E CUSTOMER SUBS	1	0	0	0	1	0	0	1	0
13	E COMMON	10	0	0	3	2	5	0	10	0
14	TOTAL E	11	0	0	3	3	5	0	11	0
15	F CUSTOMER SUBS	0	0	0	0	0	0	0	0	0
16	F COMMON	73	0	2	28	28	15	0	73	0
17	TOTAL F	73	0	2	28	28	15	0	73	0
18	G CUSTOMER SUBS	0	0	0	0	0	0	0	0	0
19	G COMMON	443,246	386,033	29,154	17,466	248	33	10,312	443,246	0
20	TOTAL G	443,246	386,033	29,154	17,466	248	33	10,312	443,246	0
21	AVERAGE CUSTOMERS	443,351	386,033	29,156	17,497	284	68	10,312	443,350	1

Supporting Schedules:

Recap Schedules: E-16

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Derive each allocation factor used in the cost of service studies. Provide supporting data and any workpapers used in deriving the allocation factors, and a brief narrative description of the development of each allocation factor.

Type of Data Shown:
X Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
___ Historical Year Ended 12/31/12
Witness: M. T. O'Sheasy

Allocation Method:12MCP - 1/13th kWh - Minimum Distribution Method

12/13 DEMAND ALLOCATION
ENERGY ALLOCATORS BY RATE CLASS

(1) LINE NO.	(2) DESCRIPTION	(3) TOTAL ELECTRIC SYSTEM	(4) RATE CLASS RESIDENTIAL	(5) RATE CLASS GS	(6) RATE CLASS GSD/GSDT	(7) RATE CLASS LP/LPT	(8) RATE CLASS MAJOR ACCTS	(9) RATE CLASS OS	(10) TOTAL RETAIL SERVICE	(11) WHOLESALE
1	LEVEL 5									
2	COMMON									
3	SALES	9,212,622	5,264,445	291,278	2,718,685	777,250	7,375	153,590	9,212,622	0
4	LOSSES	257,109	146,922	8,129	75,874	21,692	206	4,286	257,109	0
5	INTO	9,469,731	5,411,367	299,407	2,794,559	798,942	7,581	157,876	9,469,731	0
6	CUSTOMER SUBS									
7	SALES	0	0	0	0	0	0	0	0	0
8	LOSSES	0	0	0	0	0	0	0	0	0
9	INTO	0	0	0	0	0	0	0	0	0
10	TOTAL LEVEL 5									
11	SALES	9,212,622	5,264,445	291,278	2,718,685	777,250	7,375	153,590	9,212,622	0
12	LOSSES	257,109	146,922	8,129	75,874	21,692	206	4,286	257,109	0
13	INTO	9,469,731	5,411,367	299,407	2,794,559	798,942	7,581	157,876	9,469,731	0
14	LEVEL 4									
15	OUT	9,469,731	5,411,367	299,407	2,794,559	798,942	7,581	157,876	9,469,731	0
16	SALES	598,864	0	5	13,477	279,456	305,925	0	598,864	0
17	LOSSES	274,790	147,687	8,171	76,636	29,431	8,556	4,309	274,790	0
18	INTO	10,343,386	5,559,054	307,583	2,864,672	1,107,829	322,063	162,185	10,343,386	0

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Derive each allocation factor used in the cost of service studies. Provide supporting data and any workpapers used in deriving the allocation factors, and a brief narrative description of the development of each allocation factor.

Type of Data Shown:
X Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
___ Historical Year Ended 12/31/12
Witness: M. T. O'Sheasy

Allocation Method:12MCP - 1/13th kWh - Minimum Distribution Method

12/13 DEMAND ALLOCATION
ENERGY ALLOCATORS BY RATE CLASS

(1) LINE NO.	(2) DESCRIPTION	(3) TOTAL ELECTRIC SYSTEM	(4) RATE CLASS RESIDENTIAL	(5) RATE CLASS GS	(6) RATE CLASS GSD/GSDT	(7) RATE CLASS LP/LPT	(8) RATE CLASS MAJOR ACCTS	(9) RATE CLASS OS	(10) TOTAL RETAIL SERVICE	(11) WHOLESALE
1	LEVEL 3									
2	COMMON									
3	OUT	10,343,386	5,559,054	307,583	2,884,672	1,107,829	322,063	162,185	10,343,386	0
4	SALES	347,580	0	0	1,525	12,056	333,998	0	347,580	0
5	LOSSES	38,479	20,008	1,107	10,388	4,031	2,361	584	38,479	0
6	INTO	10,729,444	5,579,062	308,690	2,896,585	1,123,916	658,421	162,769	10,729,444	0
7	CUSTOMER SUBS									
8	SALES	1,113,805	0	0	0	164,892	597,865	0	762,757	351,048
9	LOSSES	4,007	0	0	0	593	2,151	0	2,744	1,263
10	INTO	1,117,812	0	0	0	165,485	600,016	0	765,501	352,311
11	TOTAL LEVEL 3									
12	OUT	10,343,386	5,559,054	307,583	2,884,672	1,107,829	322,063	162,185	10,343,386	0
13	SALES	1,461,385	0	0	1,525	176,948	931,863	0	1,110,337	351,048
14	LOSSES	42,486	20,008	1,107	10,388	4,624	4,512	584	41,223	1,263
15	INTO	11,847,257	5,579,062	308,690	2,896,585	1,289,401	1,258,438	162,769	11,494,945	352,311
16	LEVEL 2									
17	OUT	11,847,257	5,579,062	308,690	2,896,585	1,289,401	1,258,438	162,769	11,494,945	352,311
18	SALES	232,455	0	0	0	0	232,455	0	232,455	0
19	LOSSES	140,101	64,706	3,580	33,595	14,955	17,291	1,888	138,015	4,086
20	INTO	12,219,812	5,643,768	312,270	2,930,180	1,304,358	1,508,184	164,657	11,863,415	356,397
21	LEVEL 1									
22	OUT	12,219,812	5,643,768	312,270	2,930,180	1,304,356	1,508,184	164,657	11,863,415	356,397

Supporting Schedules:

Recap Schedules: E-16

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Derive each allocation factor used in the cost of service studies. Provide supporting data and any workpapers used in deriving the allocation factors, and a brief narrative description of the development of each allocation factor.

Type of Data Shown:
X Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
___ Historical Year Ended 12/31/12
___ Witness: M. T. O'Sheasy

Allocation Method:12MCP - 1/13th kWh - Minimum Distribution Method

12/13 DEMAND ALLOCATION
12-MCP DEMAND ALLOCATORS BY RATE CLASS

(1) LINE NO.	(2) DESCRIPTION	(3) TOTAL ELECTRIC SYSTEM	(4) RATE CLASS RESIDENTIAL	(5) RATE CLASS GS	(6) RATE CLASS GSD/GSDT	(7) RATE CLASS LP/LPT	(8) RATE CLASS MAJOR ACCTS	(9) RATE CLASS OS	(10) TOTAL RETAIL SERVICE	(11) WHOLESALE
1	LEVEL 5									
2	COMMON									
3	SALES	1,611,650	1,036,422	50,506	405,175	110,471	1,128	7,948	1,611,650	0
4	LOSSES	62,244	40,026	1,951	15,648	4,268	44	307	62,244	0
5	INTO	1,673,894	1,076,448	52,457	420,823	114,739	1,172	8,255	1,673,894	0
6	CUSTOMER SUBS									
7	SALES	0	0	0	0	0	0	0	0	0
8	LOSSES	0	0	0	0	0	0	0	0	0
9	INTO	0	0	0	0	0	0	0	0	0
10	TOTAL LEVEL 5									
11	SALES	1,611,650	1,036,422	50,506	405,175	110,471	1,128	7,948	1,611,650	0
12	LOSSES	62,244	40,026	1,951	15,648	4,268	44	307	62,244	0
13	INTO	1,673,894	1,076,448	52,457	420,823	114,739	1,172	8,255	1,673,894	0
14	LEVEL 4									
15	OUT	1,673,894	1,076,448	52,457	420,823	114,739	1,172	8,255	1,673,894	0
16	SALES	87,288	0	1	2,020	40,842	44,425	0	87,288	0
17	LOSSES	68,442	41,832	2,039	16,432	6,046	1,772	321	68,442	0
18	INTO	1,829,624	1,118,280	54,497	439,275	161,627	47,369	8,576	1,829,624	0

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Derive each allocation factor used in the cost of service studies. Provide supporting data and any workpapers used in deriving the allocation factors, and a brief narrative description of the development of each allocation factor.

Type of Data Shown:
X Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
___ Historical Year Ended 12/31/12
Witness: M. T. O'Sheasy

Allocation Method: 12MCP - 1/13th kWh - Minimum Distribution Method

12/13 DEMAND ALLOCATION
12-MCP DEMAND ALLOCATORS BY RATE CLASS

(1) LINE NO.	(2) DESCRIPTION	(3) TOTAL ELECTRIC SYSTEM	(4) RATE CLASS RESIDENTIAL	(5) RATE CLASS GS	(6) RATE CLASS GSD/GSDT	(7) RATE CLASS LP/LPT	(8) RATE CLASS MAJOR ACCTS	(9) RATE CLASS OS	(10) TOTAL RETAIL SERVICE	(11) WHOLESALE
1	LEVEL 3									
2	COMMON									
3	OUT	1,829,624	1,116,280	54,497	439,275	161,627	47,369	6,576	1,829,624	0
4	SALES	54,361	0	0	1,550	1,498	51,313	0	54,361	0
5	LOSSES	6,441	5,010	244	1,975	731	443	38	8,441	0
6	INTO	1,892,426	1,123,290	54,741	442,800	163,856	99,125	6,614	1,892,426	0
7	CUSTOMER SUBS									
8	SALES	182,113	0	0	0	24,453	95,024	0	119,477	62,636
9	LOSSES	616	0	0	0	110	425	0	535	281
10	INTO	182,929	0	0	0	24,583	95,449	0	120,012	62,917
11	TOTAL LEVEL 3									
12	OUT	1,629,624	1,116,280	54,497	439,275	161,627	47,369	8,576	1,829,624	0
13	SALES	236,474	0	0	1,550	25,951	146,337	0	173,838	62,636
14	LOSSES	9,257	5,010	244	1,975	841	868	38	8,976	281
15	INTO	2,075,355	1,123,290	54,741	442,800	188,419	194,574	6,614	2,012,438	62,917
16	LEVEL 2									
17	OUT	2,075,355	1,123,290	54,741	442,800	188,419	194,574	8,614	2,012,438	62,917
18	SALES	34,767	0	0	0	0	34,767	0	34,767	0
19	LOSSES	39,211	20,874	1,017	6,228	3,501	4,282	160	38,042	1,169
20	INTO	2,149,333	1,144,164	55,758	451,028	191,920	233,603	6,774	2,085,247	64,086
21	LEVEL 1									
22	OUT	2,149,333	1,144,164	55,758	451,028	191,920	233,603	6,774	2,085,247	64,086

Supporting Schedules:

Recap Schedules: E-16

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Derive each allocation factor used in the cost of service studies. Provide supporting data and any workpapers used in deriving the allocation factors, and a brief narrative description of the development of each allocation factor.

Type of Data Shown:
X Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
___ Historical Year Ended 12/31/12
Witness: M. T. O'Sheasy

Allocation Method:12MCP - 1/13th kWh - Minimum Distribution Method

12/13 DEMAND ALLOCATION
NCP DEMAND ALLOCATORS BY RATE CLASS

(1) LINE NO.	(2) DESCRIPTION	(3) TOTAL ELECTRIC SYSTEM	(4) RATE CLASS RESIDENTIAL	(5) RATE CLASS GS	(6) RATE CLASS GSD/GSDT	(7) RATE CLASS LP/LPT	(8) RATE CLASS MAJOR ACCTS	(9) RATE CLASS OS	(10) TOTAL RETAIL SERVICE	(11) WHOLESALE
1	LEVEL 5									
2	COMMON									
3	SALES	2,166,677	1,344,458	72,652	558,496	152,418	4,135	34,520	2,166,677	0
4	LOSSES	83,680	51,924	2,806	21,570	5,887	160	1,333	83,680	0
5	INTO	2,250,357	1,396,380	75,458	580,066	158,305	4,295	35,853	2,250,357	0
8	CUSTOMER SUBS									
7	SALES	0	0	0	0	0	0	0	0	0
8	LOSSES	0	0	0	0	0	0	0	0	0
9	INTO	0	0	0	0	0	0	0	0	0
10	TOTAL LEVEL 5									
11	SALES	2,166,677	1,344,458	72,652	558,496	152,418	4,135	34,520	2,166,677	0
12	LOSSES	83,680	51,924	2,808	21,570	5,887	160	1,333	83,680	0
13	INTO	2,250,357	1,396,380	75,458	580,066	158,305	4,295	35,853	2,250,357	0
14	LEVEL 4									
15	OUT	2,250,357	1,396,380	75,458	580,066	158,305	4,295	35,853	2,250,357	0
16	SALES	143,037	0	8	3,696	53,559	85,774	0	143,037	0
17	LOSSES	93,010	54,265	2,933	22,686	8,233	3,500	1,393	93,010	0
18	INTO	2,486,404	1,450,645	78,399	606,448	220,097	93,569	37,246	2,486,404	0

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Derive each allocation factor used in the cost of service studies. Provide supporting data and any workpapers used in deriving the allocation factors, and a brief narrative description of the development of each allocation factor.

Type of Data Shown:
X Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
___ Historical Year Ended 12/31/12
___ Witness: M. T. O'Sheasy

Allocation Method:12MCP - 1/13th kWh - Minimum Distribution Method

12/13 DEMAND ALLOCATION
NCP DEMAND ALLOCATORS BY RATE CLASS

(1) LINE NO.	(2) DESCRIPTION	(3) TOTAL ELECTRIC SYSTEM	(4) RATE CLASS RESIDENTIAL	(5) RATE CLASS GS	(6) RATE CLASS GSD/GSDT	(7) RATE CLASS LP/LPT	(8) RATE CLASS MAJOR ACCTS	(9) RATE CLASS OS	(10) TOTAL RETAIL SERVICE	(11) WHOLESALE
1	LEVEL 3									
2	COMMON									
3	OUT	2,486,404	1,450,645	78,399	606,448	220,097	93,569	37,246	2,486,404	0
4	SALES	0	0	0	0	0	0	0	0	0
5	LOSSES	11,139	6,499	351	2,717	988	419	167	11,139	0
6	INTO	2,497,543	1,457,144	78,750	609,165	221,083	93,988	37,413	2,497,543	0
7	CUSTOMER SUBS									
8	SALES	0	0	0	0	0	0	0	0	0
9	LOSSES	0	0	0	0	0	0	0	0	0
10	INTO	0	0	0	0	0	0	0	0	0
11	TOTAL LEVEL 3									
12	OUT	2,486,404	1,450,645	78,399	606,448	220,097	93,569	37,246	2,486,404	0
13	SALES	0	0	0	0	0	0	0	0	0
14	LOSSES	11,139	6,499	351	2,717	988	419	167	11,139	0
15	INTO	2,497,543	1,457,144	78,750	609,165	221,083	93,988	37,413	2,497,543	0
16	LEVEL 2									
17	OUT	2,497,543	1,457,144	78,750	609,165	221,083	93,988	37,413	2,497,543	0
18	SALES	0	0	0	0	0	0	0	0	0
19	LOSSES	46,410	27,077	1,463	11,320	4,108	1,747	695	46,410	0
20	INTO	2,543,953	1,484,221	80,213	620,485	225,191	95,735	38,108	2,543,953	0
21	LEVEL 1									
22	OUT	2,543,953	1,484,221	80,213	620,485	225,191	95,735	38,108	2,543,953	0

Supporting Schedules:

Recap Schedules: E-18

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Derive each allocation factor used in the cost of service studies. Provide supporting data and any workpapers used in deriving the allocation factors, and a brief narrative description of the development of each allocation factor.

Type of Data Shown:
X Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
___ Historical Year Ended 12/31/12
___ Witness: M. T. O'Sheasy

Allocation Method: 12MCP - 1/13th kWh

Line No.

1 Demand Related

METHODOLOGY FOR DEVELOPING ALLOCATION FACTORS

2 Demand Allocators are developed for each respective level. Level 1 and 2 are identical, since Gulf does not make any sales at Level 1. This allocator and the Level 3
3 demand allocator are calculated by the 12-MCP method. Levels 4 and 5 are based on the annual non-coincident peak demands for each respective rate class.

4 The numeric designations refer to the following voltage levels:

5	Level	Description	Voltage
6	1	Production	
7	2	Transmission Step-Up Substations	
8		Transmission Lines	115/230
9		Transmission Substations maintaining	115/230 to 46
10		integrity of the transmission grid	
11		Subtransmission Lines	46
12	3	Transmission and Distribution Substations	115/230 to 12
13		making a transformation from Transmission	and 46 to 12
14		voltage to Distribution voltage	and lower
15	4	Primary Distribution Lines	Less than 22
16	5	Secondary Distribution (line transformers)	

17 Production level costs are allocated first to jurisdiction on a Level 1 12-MCP allocator. The retail jurisdiction resultant is then divided into two pieces:
18 one piece which is 12/13 of the retail portion is then allocated back to retail rates upon the appropriate Level 1 12-MCP allocator, while the remaining piece,
19 which is the 1/13 of the retail portion, is then allocated back to retail rates upon the appropriate Level 1 Energy Allocator.

20 Mr. Thompson provides the 12-MCP demand for each rate class by level and also provides the total system losses. The load flow process, as described in
21 Mr. O'Sheasy's testimony, internally calculates the 12-MCP demand allocators by rate and level adjusted for losses.

FLORIDA PUBLIC SERVICE COMMISSION

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___ Historical Year Ended 12/31/12
___ Witness: M. T. O'Sheasy

Allocation Method: 12MCP - 1/13th kWh

Line No.

1 METHODOLOGY FOR DEVELOPING ALLOCATION FACTORS

2 Demand levels 4 and 5 are allocated on the annual non-coincident peak demand (NCP). The NCP demands are provided by Mr. Thompson, and the loss factors
3 developed in the 12-MCP load balance are used to adjust for losses. Workpapers for all the demand and energy allocators are attached.

4 Energy Related

5 Mr. O'Sheasy's testimony describes the development of the energy allocator. Related workpapers are attached.

6 Customer Related

7 Mr. Thompson provided the average number of customers by rate and level for the test period. These allocators are summarized in Schedule 5.

8 The customer accounts expense was directly assigned to rate, provided by Gulf Power Company. Uncollectible expense was directly assigned to rate, provided by Gulf Power Company.

9 Gulf Power Company provided a breakdown of each customer assistance expense account. The analysis of these accounts to rate is detailed
10 in Exhibit_____MTO-2.

11 Accounts 364 - 370 were classified as customer and demand related using the non-Minimum Distribution System as explained in Mr. O'Sheasy's testimony.

12 Account 370 was classified as customer related and was allocated to rate according to the following analysis: Single phase watthour meters were allocated
13 between RS, GS, and GSD based on the number of meters installed. All other single phase meters were assigned to GSD. Three phase
14 watthour meters were allocated to RS, GS, and GSD based on the number of meters installed. Three phase demand meters were allocated to GS
15 and GSD based on the number of metered customers. Accessory equipment was allocated to all rate classes based on the number of
16 meters installed. AMI single phase meters were allocated to RS, GS, GSD and OS based on number of single phase meters installed and AMI three phase meters were
17 allocated to RS, GS, GSD, LP, Major Accounts, and OS based on number of three phase meters install

18 Other Related

19 Salaries and Wages were provided by function for the test period. The production portion was allocated to jurisdiction upon 12-MCP. The retail portion was then
20 allocated to retail rates upon the 12-MCP and 1/13 energy methodology mentioned above under demand. The other functional amounts were allocated to rate on the
21 corresponding operation and maintenance expenses. The functional split and results are summarized in Exhibit_____MTO-2.

Supporting Schedules: Recap Schedules: E-16

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

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Type of Data Shown:
X Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
___ Historical Year Ended 12/31/12
___ Witness: M. T. O'Sheasy

Allocation Method: 12MCP - 1/13th kWh

12/13 DEMAND ALLOCATION
AVERAGE NUMBER OF CUSTOMERS

(1) LINE NO.	(2) DESCRIPTION	(3) TOTAL ELECTRIC SYSTEM	(4) RATE CLASS RESIDENTIAL	(5) RATE CLASS GS	(6) RATE CLASS GSD/GSDT	(7) RATE CLASS LP/LPT	(8) RATE CLASS MAJOR ACCTS	(9) RATE CLASS OS	(10) TOTAL RETAIL SERVICE	(11) WHOLESALE
1	LEVEL									
2	A	0	0	0	0	0	0	0	0	0
3	B-1	0	0	0	0	0	0	0	0	0
4	B-2	3	0	0	0	0	3	0	3	0
5	C-1 CUSTOMER SUBS	0	0	0	0	0	0	0	0	0
6	C-1 COMMON	0	0	0	0	0	0	0	0	0
7	TOTAL C-1	0	0	0	0	0	0	0	0	0
8	C-2 CUSTOMER SUBS	11	0	0	0	4	6	0	10	1
9	C-2 COMMON	7	0	0	0	1	6	0	7	0
10	TOTAL C-2	18	0	0	0	5	12	0	17	1
11	D	0	0	0	0	0	0	0	0	0
12	E CUSTOMER SUBS	1	0	0	0	1	0	0	1	0
13	E COMMON	10	0	0	3	2	5	0	10	0
14	TOTAL E	11	0	0	3	3	5	0	11	0
15	F CUSTOMER SUBS	0	0	0	0	0	0	0	0	0
16	F COMMON	73	0	2	28	28	15	0	73	0
17	TOTAL F	73	0	2	28	28	15	0	73	0
18	G CUSTOMER SUBS	0	0	0	0	0	0	0	0	0
19	G COMMON	443,246	386,033	29,154	17,466	248	33	10,312	443,246	0
20	TOTAL G	443,246	386,033	29,154	17,466	248	33	10,312	443,246	0
21	AVERAGE CUSTOMERS	443,351	386,033	29,156	17,497	284	68	10,312	443,350	1

Supporting Schedules:

Recap Schedules: E-16

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

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Witness: M. T. O'Sheasy

Allocation Method: 12MCP - 1/13th kWh

12/13 DEMAND ALLOCATION
ENERGY ALLOCATORS BY RATE CLASS

(1) LINE NO.	(2) DESCRIPTION	(3) TOTAL ELECTRIC SYSTEM	(4) RATE CLASS RESIDENTIAL	(5) RATE CLASS GS	(6) RATE CLASS GSD/GSDT	(7) RATE CLASS LP/LPT	(8) RATE CLASS MAJOR ACCTS	(9) RATE CLASS OS	(10) TOTAL RETAIL SERVICE	(11) WHOLESALE
1	LEVEL 5									
2	COMMON									
3	SALES	9,212,622	5,264,445	291,276	2,718,685	777,250	7,375	153,590	9,212,622	0
4	LOSSES	257,109	146,922	8,129	75,874	21,692	206	4,286	257,109	0
5	INTO	9,469,731	5,411,367	299,407	2,794,559	798,942	7,581	157,876	9,469,731	0
6	CUSTOMER SUBS									
7	SALES	0	0	0	0	0	0	0	0	0
8	LOSSES	0	0	0	0	0	0	0	0	0
9	INTO	0	0	0	0	0	0	0	0	0
10	TOTAL LEVEL 5									
11	SALES	9,212,622	5,264,445	291,278	2,718,685	777,250	7,375	153,590	9,212,622	0
12	LOSSES	257,109	146,922	8,129	75,874	21,692	206	4,286	257,109	0
13	INTO	9,469,731	5,411,367	299,407	2,794,559	798,942	7,581	157,876	9,469,731	0
14	LEVEL 4									
15	OUT	9,469,731	5,411,367	299,407	2,794,559	798,942	7,581	157,876	9,469,731	0
16	SALES	598,864	0	5	13,477	279,456	305,925	0	598,864	0
17	LOSSES	274,790	147,687	8,171	76,636	29,431	8,556	4,309	274,790	0
18	INTO	10,343,386	5,559,054	307,583	2,884,672	1,107,829	322,063	162,185	10,343,386	0

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

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Type of Data Shown:
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___ Witness: M. T. O'Sheasy

Allocation Method: 12MCP - 1/13th kWh

12/13 DEMAND ALLOCATION
ENERGY ALLOCATORS BY RATE CLASS

(1) LINE NO.	(2) DESCRIPTION	(3) TOTAL ELECTRIC SYSTEM	(4) RATE CLASS RESIDENTIAL	(5) RATE CLASS GS	(6) RATE CLASS GSD/GSDT	(7) RATE CLASS LP/LPT	(8) RATE CLASS MAJOR ACCTS	(9) RATE CLASS OS	(10) TOTAL RETAIL SERVICE	(11) WHOLESALE
1	LEVEL 3									
2	COMMON									
3	OUT	10,343,386	5,559,054	307,583	2,884,672	1,107,829	322,063	162,185	10,343,386	0
4	SALES	347,580	0	0	1,525	12,056	333,998	0	347,580	0
5	LOSSES	38,479	20,008	1,107	10,388	4,031	2,361	584	38,479	0
6	INTO	10,729,444	5,579,062	308,690	2,896,585	1,123,916	658,421	162,769	10,729,444	0
7	CUSTOMER SUBS									
8	SALES	1,113,805	0	0	0	184,892	597,865	0	762,757	351,048
9	LOSSES	4,007	0	0	0	593	2,151	0	2,744	1,263
10	INTO	1,117,812	0	0	0	165,485	600,016	0	765,501	352,311
11	TOTAL LEVEL 3									
12	OUT	10,343,388	5,559,054	307,583	2,884,672	1,107,829	322,063	162,185	10,343,388	0
13	SALES	1,461,385	0	0	1,525	176,948	931,863	0	1,110,337	351,048
14	LOSSES	42,486	20,008	1,107	10,388	4,624	4,512	584	41,223	1,263
15	INTO	11,847,257	5,579,062	308,690	2,896,585	1,289,401	1,258,438	162,769	11,494,945	352,311
16	LEVEL 2									
17	OUT	11,847,257	5,579,062	308,690	2,896,585	1,289,401	1,258,438	162,769	11,494,945	352,311
18	SALES	232,455	0	0	0	0	232,455	0	232,455	0
19	LOSSES	140,101	84,706	3,580	33,595	14,955	17,291	1,888	136,015	4,086
20	INTO	12,219,812	5,643,768	312,270	2,930,180	1,304,356	1,508,184	164,657	11,863,415	356,397
21	LEVEL 1									
22	OUT	12,219,812	5,643,768	312,270	2,930,180	1,304,356	1,508,184	184,657	11,863,415	356,397

Supporting Schedules:

Recap Schedules: E-16

FLORIDA PUBLIC SERVICE COMMISSION

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Type of Data Shown:
X Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
___ Historical Year Ended 12/31/12
Witness: M. T. O'Sheasy

Allocation Method: 12MCP - 1/13th kWh

12/13 DEMAND ALLOCATION
12-MCP DEMAND ALLOCATORS BY RATE CLASS

(1) LINE NO.	(2) DESCRIPTION	(3) TOTAL ELECTRIC SYSTEM	(4) RATE CLASS RESIDENTIAL	(5) RATE CLASS GS	(6) RATE CLASS GSD/GSDT	(7) RATE CLASS LP/LPT	(8) RATE CLASS MAJOR ACCTS	(9) RATE CLASS OS	(10) TOTAL RETAIL SERVICE	(11) WHOLESALE
1	LEVEL 5									
2	COMMON									
3	SALES	1,611,650	1,036,422	50,506	405,175	110,471	1,128	7,948	1,611,650	0
4	LOSSES	62,244	40,026	1,951	15,648	4,268	44	307	62,244	0
5	INTO	1,673,894	1,076,448	52,457	420,823	114,739	1,172	8,255	1,673,894	0
6	CUSTOMER SUBS									
7	SALES	0	0	0	0	0	0	0	0	0
8	LOSSES	0	0	0	0	0	0	0	0	0
9	INTO	0	0	0	0	0	0	0	0	0
10	TOTAL LEVEL 5									
11	SALES	1,611,650	1,036,422	50,506	405,175	110,471	1,128	7,948	1,611,650	0
12	LOSSES	62,244	40,026	1,951	15,648	4,268	44	307	62,244	0
13	INTO	1,673,894	1,076,448	52,457	420,823	114,739	1,172	8,255	1,673,894	0
14	LEVEL 4									
15	OUT	1,673,894	1,076,448	52,457	420,823	114,739	1,172	8,255	1,673,894	0
16	SALES	87,288	0	1	2,020	40,842	44,425	0	87,268	0
17	LOSSES	68,442	41,832	2,039	16,432	6,046	1,772	321	68,442	0
18	INTO	1,829,624	1,118,280	54,497	439,275	161,627	47,369	8,576	1,829,624	0

Supporting Schedules:

Recap Schedules: E-16

FLORIDA PUBLIC SERVICE COMMISSION

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Type of Data Shown:
X Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
___ Historical Year Ended 12/31/12
Witness: M. T. O'Sheasy

Allocation Method: 12MCP - 1/13th kWh

12/13 DEMAND ALLOCATION
12-MCP DEMAND ALLOCATORS BY RATE CLASS

(1) LINE NO.	(2) DESCRIPTION	(3) TOTAL ELECTRIC SYSTEM	(4) RATE CLASS RESIDENTIAL	(5) RATE CLASS GS	(6) RATE CLASS GSD/GSDT	(7) RATE CLASS LP/LPT	(8) RATE CLASS MAJOR ACCTS	(9) RATE CLASS OS	(10) TOTAL RETAIL SERVICE	(11) WHOLESALE
1	LEVEL 3									
2	COMMON									
3	OUT	1,829,624	1,118,280	54,497	439,275	161,627	47,369	8,576	1,829,624	0
4	SALES	54,361	0	0	1,550	1,498	51,313	0	54,361	0
5	LOSSES	8,441	5,010	244	1,975	731	443	38	8,441	0
6	INTO	1,892,426	1,123,290	54,741	442,800	163,856	99,125	8,614	1,892,426	0
7	CUSTOMER SUBS									
8	SALES	182,113	0	0	0	24,453	95,024	0	119,477	62,636
9	LOSSES	816	0	0	0	110	425	0	535	281
10	INTO	182,929	0	0	0	24,563	95,449	0	120,012	62,917
11	TOTAL LEVEL 3									
12	OUT	1,829,624	1,118,280	54,497	439,275	161,627	47,369	8,576	1,829,624	0
13	SALES	236,474	0	0	1,550	25,951	146,337	0	173,838	62,636
14	LOSSES	9,257	5,010	244	1,975	841	868	38	8,976	281
15	INTO	2,075,355	1,123,290	54,741	442,800	188,419	194,574	8,614	2,012,438	62,917
16	LEVEL 2									
17	OUT	2,075,355	1,123,290	54,741	442,800	188,419	194,574	8,614	2,012,438	62,917
18	SALES	34,767	0	0	0	0	34,767	0	34,767	0
19	LOSSES	39,211	20,874	1,017	8,228	3,501	4,262	160	38,042	1,169
20	INTO	2,149,333	1,144,164	55,758	451,028	191,920	233,603	8,774	2,085,247	64,086
21	LEVEL 1									
22	OUT	2,149,333	1,144,164	55,758	451,028	191,920	233,603	8,774	2,085,247	64,086

Supporting Schedules: Recap Schedules: E-16

FLORIDA PUBLIC SERVICE COMMISSION

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X Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
___ Historical Year Ended 12/31/12
___ Witness: M. T. O'Sheasy

Allocation Method: 12MCP - 1/13th kWh

12/13 DEMAND ALLOCATION
NCP DEMAND ALLOCATORS BY RATE CLASS

(1) LINE NO.	(2) DESCRIPTION	(3) TOTAL ELECTRIC SYSTEM	(4) RATE CLASS RESIDENTIAL	(5) RATE CLASS GS	(6) RATE CLASS GSD/GSDT	(7) RATE CLASS LP/LPT	(8) RATE CLASS MAJOR ACCTS	(9) RATE CLASS OS	(10) TOTAL RETAIL SERVICE	(11) WHOLESALE
1	LEVEL 5									
2	COMMON									
3	SALES	2,166,677	1,344,456	72,652	558,496	152,418	4,135	34,520	2,166,677	0
4	LOSSES	83,680	51,924	2,806	21,570	5,887	160	1,333	83,680	0
5	INTO	2,250,357	1,396,380	75,458	580,066	158,305	4,295	35,853	2,250,357	0
6	CUSTOMER SUBS									
7	SALES	0	0	0	0	0	0	0	0	0
8	LOSSES	0	0	0	0	0	0	0	0	0
9	INTO	0	0	0	0	0	0	0	0	0
10	TOTAL LEVEL 5									
11	SALES	2,166,677	1,344,456	72,652	558,496	152,418	4,135	34,520	2,166,677	0
12	LOSSES	83,680	51,924	2,806	21,570	5,887	160	1,333	83,680	0
13	INTO	2,250,357	1,396,380	75,458	580,066	158,305	4,295	35,853	2,250,357	0
14	LEVEL 4									
15	OUT	2,250,357	1,396,380	75,458	580,066	158,305	4,295	35,853	2,250,357	0
16	SALES	143,037	0	8	3,696	53,559	85,774	0	143,037	0
17	LOSSES	93,010	54,265	2,933	22,686	8,233	3,500	1,393	93,010	0
18	INTO	2,486,404	1,450,645	78,399	606,448	220,097	93,569	37,246	2,486,404	0

Supporting Schedules:

Recap Schedules: E-16

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Derive each allocation factor used in the cost of service studies. Provide supporting data and any workpapers used in deriving the allocation factors, and a brief narrative description of the development of each allocation factor.

Type of Data Shown:
X Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
___ Historical Year Ended 12/31/12
Witness: M. T. O'Sheasy

Allocation Method: 12MCP - 1/13th kWh

12/13 DEMAND ALLOCATION
NCP DEMAND ALLOCATORS BY RATE CLASS

(1) LINE NO.	(2) DESCRIPTION	(3) TOTAL ELECTRIC SYSTEM	(4) RATE CLASS RESIDENTIAL	(5) RATE CLASS GS	(6) RATE CLASS GSD/GSDT	(7) RATE CLASS LP/LPT	(8) RATE CLASS MAJOR ACCTS	(9) RATE CLASS OS	(10) TOTAL RETAIL SERVICE	(11) WHOLESALE
1	LEVEL 3									
2	COMMON									
3	OUT	2,486,404	1,450,645	78,399	606,448	220,097	93,569	37,246	2,486,404	0
4	SALES	0	0	0	0	0	0	0	0	0
5	LOSSES	11,139	6,499	351	2,717	986	419	167	11,139	0
6	INTO	2,497,543	1,457,144	78,750	609,165	221,083	93,988	37,413	2,497,543	0
7	CUSTOMER SUBS									
8	SALES	0	0	0	0	0	0	0	0	0
9	LOSSES	0	0	0	0	0	0	0	0	0
10	INTO	0	0	0	0	0	0	0	0	0
11	TOTAL LEVEL 3									
12	OUT	2,486,404	1,450,645	78,399	606,448	220,097	93,569	37,246	2,486,404	0
13	SALES	0	0	0	0	0	0	0	0	0
14	LOSSES	11,139	6,499	351	2,717	986	419	167	11,139	0
15	INTO	2,497,543	1,457,144	78,750	609,165	221,083	93,988	37,413	2,497,543	0
16	LEVEL 2									
17	OUT	2,497,543	1,457,144	78,750	609,165	221,083	93,988	37,413	2,497,543	0
18	SALES	0	0	0	0	0	0	0	0	0
19	LOSSES	46,410	27,077	1,463	11,320	4,108	1,747	695	46,410	0
20	INTO	2,543,953	1,484,221	80,213	620,485	225,191	95,735	38,108	2,543,953	0
21	LEVEL 1									
22	OUT	2,543,953	1,484,221	80,213	620,485	225,191	95,735	38,108	2,543,953	0

Supporting Schedules:

Recap Schedules: E-16

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide a description of how the coincident and noncoincident demands for the test year were developed. Include an explanation of how the demands at the meter for each class were developed and how they were expanded from the meter level to the generation level. Provide the workpapers for the actual calculations. If a methodology other than the application of ratios of class' coincident and non coincident load to actual MWH sales is used to derive projected demands, provide justification for the use of the methodology.

Type of Data Shown:
X Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
___ Historical Year Ended 12/31/09
Witness: J. I. Thompson, M. T. O'Sheasy

Line No.	
1	The coincident (CPKW) and noncoincident (NCPKW) demands for the test year were developed from balanced historic demands derived from the latest (2009) load research
2	study. The load research year energy and demands were adjusted from actual to reflect known changes in loads and rate changes for large customers between
3	the load research year and the projected test year. {The term "rate level" used here means total for that rate including all voltage levels of service. The term "voltage level"
4	means the amount occurring at a specific voltage level of service at a specific rate.} The load research year NCPKW demands at distribution voltage levels were developed
5	as a product of the rate level NCPKW and the maximum of the twelve monthly voltage level CPKW to rate level CPKW ratios. This produced the adjusted load research year
6	CPKW and NCPKW by rate and level for all but the OS rates.
7	The local hours of darkness profile was compared with the timing of Gulf's system peak demand to determine OS I/II CPKW contribution. Rather than rely on the 2009 load
8	research year alone for calculating OSI/II contribution to system peak demand, Gulf calculated a ten year average OS I/II CPKW contribution by month. A ten year average
9	OS I/II NCPKW was also utilized.
10	The OS III rate applies to fixed wattage loads such as traffic signals. These loads are billed monthly as one-twelfth (1/12) of their estimated annual kWh usage. Monthly OS III
11	demands (CPKW and NCPKW) for the load research year were calculated by multiplying monthly OS III energy by twelve to achieve an annualized kWh usage and then
12	dividing by 8760 to achieve an hourly demand.
13	The projected test year's monthly CPKW demands were developed for each rate level and each voltage level as a product of the projected month's system kW demand and
14	the ratio of the corresponding historic month's CPKW demand for each rate level or voltage level, as appropriate, to the historic month's system CPKW demand. The
15	allocation of demand losses to each meter level that produces coincident demands at the generation level is explained in Mr. O'Sheasy's testimony.
16	The projected test year's rate level NCPKW demands were developed as a product of the historic year's rate level NCPKW and the ratio of projected test year annual rate
17	level energy sales to historic year annual rate level energy sales.
18	The projected test year's distribution voltage level NCPKW demands were developed as a product of the projected test year's rate level NCPKW and the ratio of the historic
19	year's voltage level NCPKW to historic year's rate level NCPKW.

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide a description of how the coincident and noncoincident demands for the test year were developed. Include an explanation of how the demands at the meter for each class were developed and how they were expanded from the meter level to the generation level. Provide the workpapers for the actual calculations. If a methodology other than the application of ratios of class' coincident and non coincident load to actual MWH sales is used to derive projected demands, provide justification for the use of the methodology.

Type of Data Shown:
__ Projected Test Year Ended 12/31/14
__ Prior Year Ended 12/31/13
X Historical Year Ended 12/31/09
Witness: J. I. Thompson, M. T. O'Sheasy

KWH LOAD RESEARCH YEAR ADJUSTED TO TEST YEAR

(1) Line No.	(2) Rate	(3) Level	(4) Jan-09	(5) Feb-09	(6) Mar-09	(7) Apr-09	(8) May-09	(9) Jun-09
1	RS	G	389,447,240	410,016,207	337,123,609	301,941,391	358,866,739	495,405,137
2	RSVP	G	13,063,630	12,939,417	10,854,462	9,809,125	11,988,001	15,350,157
3	RESIDENTIAL	TOTAL	402,510,870	422,955,624	347,978,071	311,750,516	370,854,740	510,755,294
4	GS	G	21,428,174	22,316,973	19,481,088	18,789,023	21,323,534	26,722,746
5		F	840	240	840	840	160	160
6	GS	TOTAL	21,429,014	22,317,213	19,481,928	18,789,863	21,323,714	26,722,926
7	GSD/GSDT	G	193,120,462	186,239,769	183,612,203	189,336,999	210,747,842	248,805,263
8		F	928,572	909,874	872,605	870,155	908,676	1,405,617
9		E	72,103	56,849	63,464	64,212	76,351	78,869
10	GSD/GSDT	TOTAL	194,121,137	187,206,492	184,548,272	190,271,366	211,732,869	250,289,749
11	LP	G	35,254,452	32,645,460	32,537,064	34,104,891	36,141,409	40,641,901
12		F	6,729,330	6,305,509	6,660,025	6,849,610	7,639,404	7,868,054
13		E	278,958	288,773	252,547	275,372	308,070	361,792
14		C2	915,600	864,900	914,400	1,185,900	1,172,100	1,332,300
15	LP	TOTAL	43,178,340	40,104,642	40,364,036	42,415,773	45,260,983	50,204,047
16	LPT	G	30,199,976	29,614,618	24,669,674	31,173,335	21,164,632	31,759,810
17		F	14,927,172	14,054,581	14,634,424	15,175,202	15,829,238	17,137,391
18		ES	1,989,344	1,786,233	2,045,039	2,067,378	2,388,580	2,750,741
19		E	8,113,413	7,286,236	8,124,598	8,105,744	9,829,774	11,239,169
20		C2S	18,619,538	17,747,925	18,519,589	20,470,512	21,630,957	24,303,245
21		C2	760,227	715,601	799,129	760,085	814,624	692,118
22		B2S	18,441,094	16,997,556	19,062,320	19,366,588	22,042,888	23,033,948
23	LPT	TOTAL	93,050,764	88,202,750	87,854,773	97,118,844	93,700,693	110,916,422
24	LP/LPT	TOTAL	136,229,104	128,307,392	128,218,809	139,534,617	138,961,876	161,120,469

02

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide a description of how the coincident and noncoincident demands for the test year were developed. Include an explanation of how the demands at the meter for each class were developed and how they were expanded from the meter level to the generation level. Provide the workpapers for the actual calculations. If a methodology other than the application of ratios of class' coincident and non coincident load to actual MWH sales is used to derive projected demands, provide justification for the use of the methodology.

Type of Data Shown:
__ Projected Test Year Ended 12/31/14
__ Prior Year Ended 12/31/13
X Historical Year Ended 12/31/09
Witness: J. I. Thompson, M. T. O'Sheasy

KWH LOAD RESEARCH YEAR ADJUSTED TO TEST YEAR

(1) Line No.	(2) Rate	(3) Level	(4) Jul-09	(5) Aug-09	(6) Sep-09	(7) Oct-09	(8) Nov-09	(9) Dec-09	(10) Annual kWh
1	RS	G	602,130,374	556,570,366	478,184,033	442,211,857	294,180,593	363,306,660	5,029,384,426
2	RSVP	G	18,747,334	17,376,536	16,640,237	14,085,972	11,206,771	11,877,906	163,939,548
3	RESIDENTIAL	TOTAL	620,877,708	573,946,902	494,824,270	456,297,829	305,387,364	375,184,766	5,193,323,974
4	GS	G	30,443,232	29,031,008	25,982,439	24,642,746	17,882,694	19,942,297	277,965,954
5		F	240	360	0	120	120	1,080	5,040
6	GS	TOTAL	30,443,472	29,031,368	25,982,439	24,642,866	17,882,814	19,943,377	277,990,994
7	GSD/GSDT	G	273,766,048	261,178,879	249,478,263	235,258,744	180,117,109	181,772,427	2,593,454,008
8		F	1,442,727	1,191,226	1,105,632	1,099,279	1,194,594	929,920	12,858,877
9		E	79,627	81,120	81,451	77,223	71,854	90,432	893,755
10	GSD/GSDT	TOTAL	275,308,602	262,451,225	250,665,346	236,435,248	181,383,557	182,792,779	2,607,206,640
11	LP	G	42,671,733	41,844,586	41,442,101	40,258,039	32,021,627	33,771,751	443,334,994
12		F	8,402,813	8,253,270	8,156,817	7,504,745	6,013,643	6,657,510	87,040,730
13		E	363,702	362,144	358,603	317,318	270,178	263,179	3,700,636
14		C2	1,302,000	1,352,100	1,269,600	1,193,400	1,067,700	795,300	13,365,300
15	LP	TOTAL	52,740,248	51,812,080	51,227,121	49,273,502	39,373,148	41,487,740	547,441,660
16	LPT	G	35,057,846	36,319,075	38,805,391	35,769,882	38,646,939	26,844,435	360,025,613
17		F	18,915,434	17,931,405	16,892,990	17,516,046	13,786,271	14,012,584	190,812,738
18		ES	2,667,588	2,565,049	2,390,515	2,196,000	1,754,838	1,965,998	26,567,303
19		E	11,397,362	11,166,930	10,348,783	9,764,208	6,739,058	6,901,678	109,016,953
20		C2S	27,883,682	25,897,239	24,077,990	24,921,826	18,136,951	19,039,771	261,249,225
21		C2	771,210	719,698	703,115	652,429	791,248	735,187	8,914,669
22		B2S	23,968,136	24,914,854	22,014,660	21,417,784	15,786,528	17,090,588	244,136,744
23	LPT	TOTAL	120,661,258	119,514,050	115,233,444	112,238,175	95,641,831	86,590,241	1,220,723,245
24	LP/LPT	TOTAL	173,401,506	171,326,130	166,460,565	161,511,677	135,014,979	128,077,981	1,768,184,905

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide a description of how the coincident and noncoincident demands for the test year were developed. Include an explanation of how the demands at the meter for each class were developed and how they were expanded from the meter level to the generation level. Provide the workpapers for the actual calculations. If a methodology other than the application of ratios of class' coincident and non coincident load to actual MWH sales is used to derive projected demands, provide justification for the use of the methodology.

Type of Data Shown:
__ Projected Test Year Ended 12/31/14
__ Prior Year Ended 12/31/13
X Historical Year Ended 12/31/09
Witness: J. I. Thompson, M. T. O'Sheasy

KWH LOAD RESEARCH YEAR ADJUSTED TO TEST YEAR

(1) Line No.	(2) Rate	(3) Level	(4) Jan-09	(5) Feb-09	(6) Mar-09	(7) Apr-09	(8) May-09	(9) Jun-09
1	RTP	G	603,529	632,869	576,542	632,453	597,172	643,657
2		F	23,008,654	21,229,651	21,781,096	22,914,081	27,272,213	27,886,266
3		E	2,966,219	2,597,299	2,963,881	2,845,690	2,426,564	2,240,090
4		C2S	25,703,378	24,767,644	25,090,088	29,300,869	24,027,138	20,592,058
5		C2	8,050,027	6,952,470	5,347,062	7,610,843	7,481,312	7,306,482
6	RTP	TOTAL	60,331,807	56,179,933	55,756,489	63,303,936	61,804,399	56,668,553
7	SBS	F	349,197	215,192	403,434	10,925,478	22,703,887	30,660
8		C2	32,299	5,543	24,307	213,344	738,465	204,354
9		B2S	164,072	190,459	151,044	159,090	183,689	940,375
10	SBS	TOTAL	545,568	411,194	578,785	11,297,912	23,626,041	1,175,389
11	CSA	F	3,198,127	3,000,194	3,181,852	2,968,927	2,751,047	3,042,568
12	MAJOR ACCTS**	TOTAL	64,075,502	59,591,321	59,519,126	77,570,775	88,181,487	62,886,510
13	OS I&II		9,183,124	9,215,565	9,156,107	9,281,733	9,122,677	9,290,160
14	OS III		3,007,776	3,036,851	3,078,113	3,108,331	3,136,610	3,177,797
15	OS	TOTAL	12,190,900	12,252,416	12,234,220	12,390,064	12,259,287	12,467,957
16	TOTAL RETAIL SALES		630,556,527	832,630,458	751,980,426	750,307,201	843,313,773	1,024,242,905
17	RE	C2S	31,682,137	27,627,610	26,339,621	25,396,931	30,492,922	37,935,600
18	TOTAL SALES		862,238,664	860,458,068	778,320,047	775,704,132	873,806,695	1,062,178,505
19	COMPANY USE							
20	LOSSES		48,458,620	40,922,371	37,767,263	38,769,569	60,162,578	88,906,626
21	SUPPLY		910,697,284	901,380,439	816,087,310	814,473,701	933,969,273	1,151,085,131

22 **Major Accounts is the combination of Rates RTP, SBS and CSA.

Supporting Schedules: Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide a description of how the coincident and noncoincident demands for the test year were developed. Include an explanation of how the demands at the meter for each class were developed and how they were expanded from the meter level to the generation level. Provide the workpapers for the actual calculations. If a methodology other than the application of ratios of class' coincident and non coincident load to actual MWH sales is used to derive projected demands, provide justification for the use of the methodology.

Type of Data Shown:
_ Projected Test Year Ended 12/31/14
_ Prior Year Ended 12/31/13
X Historical Year Ended 12/31/09
Witness: J. I. Thompson, M. T. O'Sheasy

KWH LOAD RESEARCH YEAR ADJUSTED TO TEST YEAR

(1) Line No.	(2) Rate	(3) Level	(4) Jul-09	(5) Aug-09	(6) Sep-09	(7) Oct-09	(8) Nov-09	(9) Dec-09	(10) Annual kWh
1	RTP	G	706,775	679,426	662,207	708,909	661,776	707,953	7,813,268
2		F	30,293,851	29,610,446	29,712,461	28,796,815	22,431,569	24,838,878	309,775,981
3		E	3,126,288	3,071,103	2,849,292	3,019,284	2,735,623	2,961,817	33,802,950
4		C2S	21,492,935	22,967,691	22,027,086	22,734,255	22,299,010	24,240,128	285,242,280
5		C2	5,548,838	6,886,486	8,822,144	8,709,781	9,290,018	8,080,263	90,085,746
6	RTP	TOTAL	61,168,687	63,215,152	64,073,190	63,969,044	57,417,996	60,829,039	726,720,225
7	SBS	F	0	249,655	829	6,612,226	26,868,759	0	68,359,317
8		C2	107,572	5,746	68,086	335,482	170,507	28,533	1,934,240
9		B2S	177,156	340,550	312,364	268,910	199,522	235,295	3,342,526
10	SBS	TOTAL	284,728	595,951	381,281	7,238,618	27,238,788	263,828	73,636,083
11	CSA	F	3,331,539	3,176,346	3,085,319	3,006,032	2,939,633	3,151,692	36,633,276
12	MAJOR ACCTS**	TOTAL	64,784,954	66,987,449	67,539,790	74,211,694	87,596,417	64,244,559	837,189,584
13	OS I&II		9,125,850	9,171,443	9,068,846	9,050,174	9,135,119	9,207,342	110,008,140
14	OS III		3,179,966	3,237,817	3,233,062	3,257,939	3,190,542	3,261,486	37,906,290
15	OS	TOTAL	12,305,816	12,409,260	12,301,908	12,308,113	12,325,661	12,468,828	147,914,430
16	TOTAL RETAIL SALES		1,177,122,058	1,116,152,334	1,017,774,318	965,407,425	739,590,792	782,712,310	10,831,790,527
17	RE	C2S	36,685,696	35,666,326	32,808,496	30,051,194	26,228,963	32,686,403	373,801,899
18	TOTAL SALES		1,213,807,754	1,151,818,660	1,050,582,814	995,458,619	765,819,755	815,398,713	11,205,592,426
19	COMPANY USE								
20	LOSSES		86,684,872	76,703,694	67,574,175	52,777,459	34,558,498	47,765,045	681,050,764
21	SUPPLY		1,300,492,626	1,228,522,354	1,118,156,989	1,048,236,072	800,378,253	863,163,758	11,886,643,190

22 **Major Accounts is the combination of Rates RTP, SBS and CSA.

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide a description of how the coincident and noncoincident demands for the test year were developed. Include an explanation of how the demands at the meter for each class were developed and how they were expanded from the meter level to the generation level. Provide the workpapers for the actual calculations. If a methodology other than the application of ratios of class' coincident and non coincident load to actual MWH sales is used to derive projected demands, provide justification for the use of the methodology.

Type of Data Shown:
__ Projected Test Year Ended 12/31/14
__ Prior Year Ended 12/31/13
X Historical Year Ended 12/31/09
Witness: J. I. Thompson, M. T. O'Sheasy

KW LOAD RESEARCH YEAR ADJUSTED TO TEST YEAR

(1) Line No.	(2) Rate	(3) Level	(4) Jan-09	(5) Feb-09	(6) Mar-09	(7) Apr-09	(8) May-09	(9) Jun-09
1	RS	G	1,256,412	1,254,706	1,015,608	866,873	992,949	1,241,857
2	RSVP	G	22,921	25,920	28,698	22,430	24,614	35,540
3	RESIDENTIAL	TOTAL	1,279,333	1,280,626	1,044,306	889,303	1,017,563	1,277,397
4	GS	G	51,472	57,278	44,406	43,432	50,389	58,756
5		F	2	1	2	2	0	0
6	GS	TOTAL	51,474	57,279	44,408	43,434	50,389	58,756
7	GSD/GSDT	G	332,874	353,025	337,646	388,162	427,740	492,177
8		F	1,613	1,738	1,601	1,781	1,837	2,851
9		E	99	75	72	97	109	113
10	GSD/GSDT	TOTAL	334,587	354,838	339,318	390,040	429,686	495,142
11	LP	G	47,180	48,133	44,651	66,329	60,826	71,237
12		F	10,791	10,665	10,420	12,409	13,081	13,808
13		E	482	495	453	473	546	541
14		C2	1,174	1,018	1,002	2,126	2,139	2,417
15	LP	TOTAL	59,627	60,312	56,526	81,337	76,592	88,004
16	LPT	G	43,684	47,881	34,857	51,419	28,457	49,838
17		F	21,883	21,539	21,333	24,892	26,994	28,986
18		ES	3,763	4,086	3,350	3,767	4,185	4,906
19		E	13,298	13,762	12,575	14,812	17,093	20,501
20		C2S	27,765	28,023	26,150	34,359	39,979	43,906
21		C2	1,020	167	1,150	1,134	1,077	1,000
22		B2S	30,794	30,372	29,024	34,932	34,866	40,594
23	LPT	TOTAL	142,207	145,830	128,439	165,315	152,631	189,729
24	LP/LPT	TOTAL	201,834	206,142	184,965	246,652	229,223	277,733

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide a description of how the coincident and noncoincident demands for the test year were developed. Include an explanation of how the demands at the meter for each class were developed and how they were expanded from the meter level to the generation level. Provide the workpapers for the actual calculations. If a methodology other than the application of ratios of class' coincident and non coincident load to actual MWH sales is used to derive projected demands, provide justification for the use of the methodology.

Type of Data Shown:
__ Projected Test Year Ended 12/31/14
__ Prior Year Ended 12/31/13
X Historical Year Ended 12/31/09
Witness: J. I. Thompson, M. T. O'Sheasy

KW LOAD RESEARCH YEAR ADJUSTED TO TEST YEAR

(1) Line No.	(2) Rate	(3) Level	(4) Jul-09	(5) Aug-09	(6) Sep-09	(7) Oct-09	(8) Nov-09	(9) Dec-09	(10) 12 CPKW	(11) MAX NCPKW
1	RS	G	1,128,213	1,074,969	1,004,191	989,040	509,285	1,063,944	1,016,504	1,283,757
2	RSVP	G	28,221	28,358	26,171	23,773	16,285	26,979	25,826	42,536
3	RESIDENTIAL	TOTAL	1,156,434	1,103,327	1,030,362	1,012,813	525,570	1,090,923	1,042,330	1,307,177
4	GS	G	63,457	55,468	55,047	52,445	28,189	47,010	50,612	69,337
5		F	1	1	0	0	0	3	1	7
6	GS	TOTAL	63,457	55,469	55,047	52,445	28,189	47,013	50,613	68,451
7	GSD/GSDT	G	509,348	478,216	460,940	464,479	303,106	296,614	403,694	532,655
8		F	2,740	2,180	2,042	2,208	2,001	1,485	2,007	3,525
9		E	114	111	199	191	175	116	123	
10	GSD/GSDT	TOTAL	512,202	480,508	463,181	466,878	305,282	298,216	405,823	536,454
11	LP	G	75,285	69,652	70,777	78,313	55,739	40,641	60,729	80,453
12		F	14,305	15,103	14,401	15,556	11,090	9,292	12,577	17,942
13		E	618	494	558	563	403	414	503	
14		C2	2,597	2,215	2,275	2,670	1,983	281	1,825	
15	LP	TOTAL	92,786	87,464	88,011	97,102	69,216	50,627	75,634	97,966
16	LPT	G	56,045	58,092	58,248	60,267	59,250	37,560	48,800	78,911
17		F	29,827	28,791	28,057	29,870	22,616	19,104	25,324	36,285
18		ES	4,773	4,469	4,072	4,349	2,897	3,216	3,984	
19		E	19,467	19,525	19,257	20,135	12,689	10,465	16,132	
20		C2S	45,698	44,950	42,521	44,452	30,281	25,665	36,146	
21		C2	1,032	997	1,052	989	1,037	1,054	976	
22		B2S	40,778	44,322	37,344	39,814	25,340	24,256	34,370	
23	LPT	TOTAL	197,620	201,146	190,551	199,876	154,110	121,320	165,731	205,569
24	LP/LPT	TOTAL	290,406	288,610	278,562	296,978	223,326	171,947	241,365	303,534

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

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Type of Data Shown:
__ Projected Test Year Ended 12/31/14
__ Prior Year Ended 12/31/13
X Historical Year Ended 12/31/09
Witness: J. I. Thompson, M. T. O'Sheasy

KW LOAD RESEARCH YEAR ADJUSTED TO TEST YEAR

(1) Line No.	(2) Rate	(3) Level	(4) Jan-09	(5) Feb-09	(6) Mar-09	(7) Apr-09	(8) May-09	(9) Jun-09
1	RTP	G	731	725	686	756	748	798
2		F	43,925	33,738	43,186	41,819	45,563	46,172
3		E	4,019	3,884	3,753	4,050	1,218	4,375
4		C2S	42,260	41,844	19,189	44,098	29,754	26,393
5		C2	11,338	8,699	11,680	10,924	8,892	9,897
6	RTP	TOTAL	102,273	88,890	78,494	101,647	86,175	87,435
7	SBS	F	0	0	0	29,369	0	0
8		C2	0	0	0	0	1,169	0
9		B2S	295	930	245	204	289	572
10	SBS	TOTAL	295	930	245	29,573	1,458	572
11	CSA	F	4,620	4,970	4,549	3,639	3,851	4,399
12	MAJOR ACCTS**	TOTAL	107,188	94,790	83,288	134,859	91,484	92,406
13	OS I&II		7,783	11,524	9,008	0	0	0
14	OS III		4,120	4,160	4,217	4,258	4,297	4,353
15	OS	TOTAL	11,903	15,684	13,225	4,258	4,297	4,353
16	TOTAL RETAIL SALES		1,986,319	2,009,359	1,709,510	1,508,546	1,822,642	2,205,787
17	RE	C2S	84,158	87,882	70,055	53,481	62,618	80,728
18	TOTAL SALES		2,070,477	2,097,241	1,779,565	1,562,027	1,885,260	2,286,515
19	COMPANY USE							
20	LOSSES		202,300	207,663	143,978	108,884	163,673	251,087
21	SUPPLY		2,272,777	2,304,904	1,923,543	1,670,891	2,048,933	2,537,602

22 **Major Accounts is the combination of Rates RTP, SBS and CSA.

Supporting Schedules: Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide a description of how the coincident and noncoincident demands for the test year were developed. Include an explanation of how the demands at the meter for each class were developed and how they were expanded from the meter level to the generation level. Provide the workpapers for the actual calculations. If a methodology other than the application of ratios of class' coincident and non coincident load to actual MWH sales is used to derive projected demands, provide justification for the use of the methodology.

Type of Data Shown:
__ Projected Test Year Ended 12/31/14
__ Prior Year Ended 12/31/13
X Historical Year Ended 12/31/09
Witness: J. I. Thompson, M. T. O'Sheasy

KW LOAD RESEARCH YEAR ADJUSTED TO TEST YEAR

(1) Line No.	(2) Rate	(3) Level	(4) Jul-09	(5) Aug-09	(6) Sep-09	(7) Oct-09	(8) Nov-09	(9) Dec-09	(10) 12 CPKW	(11) MAX NCPKW
1	RTP	G	2,304	2,397	792	2,097	752	707	1,124	3,492
2		F	46,183	40,849	39,789	53,756	38,906	33,239	42,260	70,842
3		E	4,538	4,473	4,075	3,957	3,505	4,167	3,835	
4		C2S	23,227	32,790	26,447	32,914	46,434	30,703	33,004	
5		C2	8,948	7,856	12,813	8,165	14,014	8,645	10,139	
6	RTP	TOTAL	85,200	88,365	83,916	100,889	103,611	77,461	90,363	128,349
7	SBS	F	0	0	0	0	43,695	0	6,089	46,255
8		C2	0	0	0	0	575	0	145	
9		B2S	0	579	0	0	209	280	300	
10	SBS	TOTAL	0	579	0	0	44,478	280	6,534	46,576
11	CSA	F	4,554	4,410	4,409	4,259	4,208	4,462	4,361	5,000
12	MAJOR ACCTS**	TOTAL	89,754	93,354	88,325	105,146	152,297	82,203	101,258	
13	OS I&II		0	0	0	0	10,603	3,883	3,567	28,776
14	OS III		4,356	4,435	4,429	4,463	4,371	4,468	4,327	4,468
15	OS	TOTAL	4,356	4,435	4,429	4,463	14,974	8,351	7,894	33,244
16	TOTAL RETAIL SALES		2,116,609	2,025,703	1,919,906	1,938,725	1,249,638	1,698,653	1,849,283	2,427,785
17	RE	C2S	76,078	75,093	68,980	70,286	42,413	69,854	70,136	87,882
18	TOTAL SALES		2,192,687	2,100,796	1,988,886	2,009,011	1,292,051	1,768,507	1,919,419	2,515,667
19	COMPANY USE									
20	LOSSES		228,563	207,785	184,121	168,225	73,010	143,441	175,226	
21	SUPPLY		2,421,250	2,308,581	2,173,007	2,197,236	1,365,061	1,911,948	2,094,644	

22 **Major Accounts is the combination of Rates RTP, SBS and CSA.

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide a description of how the coincident and noncoincident demands for the test year were developed. Include an explanation of how the demands at the meter for each class were developed and how they were expanded from the meter level to the generation level. Provide the workpapers for the actual calculations. If a methodology other than the application of ratios of class' coincident and non coincident load to actual MWH sales is used to derive projected demands, provide justification for the use of the methodology.

Type of Data Shown:
X Projected Test Year Ended 12/31/14
__ Prior Year Ended 12/31/13
__ Historical Year Ended 12/31/09
Witness: J. I. Thompson, M. T. O'Sheasy

KWH - TEST YEAR

(1) Line No.	(2) Rate	(3) Level	(4) Jan-14	(5) Feb-14	(6) Mar-14	(7) Apr-14	(8) May-14	(9) Jun-14
1	RS	G	466,150,930	367,885,510	367,362,781	339,678,546	444,275,526	537,208,698
2	RSVP	G	16,963,195	14,192,825	13,496,854	12,534,938	16,543,718	20,191,908
3	RESIDENTIAL	TOTAL	483,114,125	402,078,335	380,859,635	352,213,484	460,819,244	557,400,606
4	GS	G	24,076,333	20,695,429	20,538,904	20,278,470	26,752,575	29,385,641
5		F	944	223	886	907	226	198
6	GS	TOTAL	24,077,277	20,695,652	20,539,790	20,279,377	26,752,801	29,385,839
7	GSD/GSDT	G	197,149,438	173,816,914	189,081,254	199,595,238	257,807,238	269,348,692
8		F	947,944	849,182	898,596	917,300	1,111,581	1,521,676
9		E	73,807	53,057	65,354	67,691	93,400	85,361
10	GSD/GSDT	TOTAL	198,170,989	174,719,153	190,045,205	200,580,229	259,012,219	270,955,750
11	LP	G	36,851,963	32,956,651	36,235,756	37,568,022	48,892,248	48,051,752
12		F	7,034,261	6,385,616	7,417,112	7,545,144	10,334,617	9,302,561
13		E	291,599	291,526	281,256	303,334	416,758	427,754
14		C2	957,089	873,145	1,018,346	1,306,320	1,585,622	1,575,206
15	LP	TOTAL	45,134,912	40,486,937	44,952,469	46,722,820	61,229,246	59,357,273
16	LPT	G	30,785,977	27,958,441	25,535,697	30,871,840	26,042,579	34,414,897
17		F	15,216,819	13,268,588	15,148,162	15,028,434	19,477,503	18,570,059
18		ES	2,027,945	1,686,339	2,116,830	2,047,383	2,939,091	2,980,700
19		E	8,270,846	6,878,758	8,409,810	8,027,349	12,095,304	12,178,752
20		C2S	19,802,832	17,475,385	19,948,715	21,083,530	27,635,361	27,609,971
21		C2	774,978	675,582	827,182	752,734	1,002,376	749,978
22		B2S	18,798,925	16,046,980	19,731,498	19,179,283	27,123,252	24,959,562
23	LPT	TOTAL	95,678,322	83,990,073	91,717,894	96,990,553	116,315,487	121,463,919
24	LP/LPT	TOTAL	140,813,234	124,477,010	136,670,363	143,713,373	177,544,733	180,821,192

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

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X Projected Test Year Ended 12/31/14
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Witness: J. I. Thompson, M. T. O'Sheasy

KWH - TEST YEAR

(1) Line No.	(2) Rate	(3) Level	(4) Jul-14	(5) Aug-14	(6) Sep-14	(7) Oct-14	(8) Nov-14	(9) Dec-14	(10) Annual kWh
1	RS	G	602,821,090	600,188,084	506,177,118	409,390,568	336,996,794	409,161,341	5,407,296,988
2	RSVP	G	22,838,133	22,897,955	19,445,172	15,822,328	13,174,580	16,181,206	204,282,812
3	RESIDENTIAL	TOTAL	625,659,223	623,086,039	525,622,290	425,212,896	350,171,374	425,342,547	5,611,579,800
4	GS	G	31,220,934	30,870,793	27,077,662	23,307,831	20,140,732	22,346,616	296,691,921
5		F	246	383	0	113	135	1,210	5,470
6	GS	TOTAL	31,221,180	30,871,176	27,077,662	23,307,944	20,140,867	22,347,826	296,697,391
7	GSD/GSDT	G	278,937,330	277,108,465	246,452,430	217,110,519	195,512,655	202,934,802	2,704,854,976
8		F	1,469,872	1,263,880	1,092,222	1,014,479	1,296,702	1,038,183	13,421,619
9		E	81,329	86,068	80,463	71,266	77,996	100,960	936,572
10	GSD/GSDT	TOTAL	280,488,531	278,458,413	247,625,116	218,196,264	196,887,353	204,073,946	2,719,213,167
11	LP	G	48,032,231	46,786,779	42,298,058	40,252,521	37,688,692	38,997,783	494,612,434
12		F	9,458,389	9,228,054	8,325,290	7,503,716	7,077,915	7,687,727	97,280,402
13		E	409,391	404,916	366,010	317,275	317,993	303,905	4,131,716
14		C2	1,465,560	1,511,795	1,295,623	1,193,236	1,256,657	918,369	14,957,167
15	LP	TOTAL	59,365,570	57,931,544	52,285,180	49,266,748	46,341,257	47,907,783	610,981,719
16	LPT	G	36,490,875	36,897,717	36,306,245	34,006,703	35,282,182	29,248,299	383,841,452
17		F	19,688,624	18,217,091	15,805,047	16,652,640	12,585,983	15,267,382	194,926,333
18		ES	2,776,629	2,805,916	2,236,561	2,087,754	1,802,055	2,142,049	27,249,252
19		E	11,863,242	11,344,844	9,682,300	9,282,908	6,152,329	7,519,709	111,706,151
20		C2S	30,286,459	27,514,639	23,654,319	24,704,372	17,324,875	21,552,743	278,593,420
21		C2	802,734	731,164	657,833	620,269	722,357	801,021	9,118,209
22		B2S	24,947,861	25,311,599	20,596,871	20,362,053	14,412,090	18,621,015	250,090,988
23	LPT	TOTAL	126,856,424	122,823,170	108,939,176	107,716,699	88,081,870	95,152,218	1,255,525,805
24	LP/LPT	TOTAL	186,221,994	180,554,714	161,224,356	156,983,447	134,423,127	143,059,981	1,866,507,524

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide a description of how the coincident and noncoincident demands for the test year were developed. Include an explanation of how the demands at the meter for each class were developed and how they were expanded from the meter level to the generation level. Provide the workpapers for the actual calculations. If a methodology other than the application of ratios of class' coincident and non coincident load to actual MWH sales is used to derive projected demands, provide justification for the use of the methodology.

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X Projected Test Year Ended 12/31/14
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Witness: J. I. Thompson, M. T. O'Sheasy

KWH - TEST YEAR

(1) Line No.	(2) Rate	(3) Level	(4) Jan-14	(5) Feb-14	(6) Mar-14	(7) Apr-14	(8) May-14	(9) Jun-14
1	RTP	G	732,206	822,843	762,295	739,335	721,841	812,891
2		F	27,914,271	27,602,358	28,798,624	26,788,452	32,965,699	35,218,271
3		E	3,598,639	3,376,955	3,918,533	3,326,598	2,933,146	2,829,066
4		C2S	31,183,531	32,202,384	33,173,721	34,252,576	29,043,166	26,006,231
5		C2	21,599,353	20,872,459	18,902,828	20,730,039	20,876,149	21,060,541
6	RTP	TOTAL	85,028,000	84,877,000	85,556,000	85,835,000	86,540,000	85,927,000
7	SBS	F	0	0	0	0	0	0
8		C2	49,344	8,484	41,586	171,851	240,241	53,555
9		B2S	250,656	291,516	258,414	128,149	59,759	246,445
10	SBS	TOTAL	300,000	300,000	300,000	300,000	300,000	300,000
11	CSA	F	3,250,000	3,250,000	3,250,000	3,250,000	3,250,000	3,250,000
12	MAJOR ACCTS**	TOTAL	88,578,000	88,427,000	89,106,000	89,385,000	90,090,000	89,477,000
13	OS I&II		9,462,864	8,815,124	9,878,151	9,896,304	10,910,858	9,981,502
14	OS III		3,535,331	3,214,845	3,746,224	3,757,471	4,266,917	3,804,485
15	OS	TOTAL	12,998,195	12,029,969	13,624,375	13,653,775	15,177,775	13,785,987
16	TOTAL RETAIL SALES		947,751,820	822,427,119	830,845,368	819,826,238	1,029,396,772	1,141,826,374
17	RE	C2S	34,148,921	29,985,486	28,845,843	28,106,626	33,914,361	37,132,693
18	TOTAL SALES		981,900,742	852,412,605	859,691,212	847,931,864	1,063,311,133	1,178,959,067
19	COMPANY USE		2,242,747	1,582,455	1,795,348	1,707,547	1,934,700	1,674,335
20	LOSSES		54,474,205	40,282,689	40,903,957	39,646,223	64,200,033	80,272,313
21	SUPPLY		1,038,617,694	894,277,749	902,390,516	889,285,634	1,129,445,866	1,260,905,714

22 Major Accounts is the combination of Rates RTP, SBS and CSA.

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide a description of how the coincident and noncoincident demands for the test year were developed. Include an explanation of how the demands at the meter for each class were developed and how they were expanded from the meter level to the generation level. Provide the workpapers for the actual calculations. If a methodology other than the application of ratios of class' coincident and non coincident load to actual MWH sales is used to derive projected demands, provide justification for the use of the methodology.

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X Projected Test Year Ended 12/31/14
_ Prior Year Ended 12/31/13
_ Historical Year Ended 12/31/09
Witness: J. I. Thompson, M. T. O'Sheasy

KWH - TEST YEAR

(1) Line No.	(2) Rate	(3) Level	(4) Jul-14	(5) Aug-14	(6) Sep-14	(7) Oct-14	(8) Nov-14	(9) Dec-14	(10) Annual KWH
1	RTP	G	859,737	798,209	768,998	831,731	848,882	852,711	9,551,680
2		F	36,850,138	34,787,214	34,504,063	33,786,007	28,773,730	29,917,784	377,904,611
3		E	3,602,889	3,608,021	3,308,785	3,542,390	3,509,076	3,567,432	41,321,530
4		C2S	26,144,501	26,983,112	25,579,300	26,673,078	28,603,692	29,196,606	349,041,898
5		C2	18,582,734	19,923,444	22,077,854	22,051,794	23,749,619	21,569,467	251,996,282
6	RTP	TOTAL	86,240,000	86,100,000	86,239,000	86,885,000	85,485,000	85,104,000	1,029,816,000
7	SBS	F	0	0	0	21,250,000	21,250,000	0	42,500,000
8		C2	113,342	4,978	53,690	161,188	138,238	32,445	1,068,942
9		B2S	186,658	295,022	246,310	138,812	161,762	267,555	2,531,058
10	SBS	TOTAL	300,000	300,000	300,000	21,550,000	21,550,000	300,000	46,100,000
11	CSA	F	3,250,000	3,250,000	3,250,000	3,250,000	3,250,000	3,250,000	39,000,000
12	MAJOR ACCTS**	TOTAL	89,790,000	89,650,000	89,789,000	111,685,000	110,285,000	88,654,000	1,114,916,000
13	OS I&II		9,728,160	9,533,036	8,920,419	9,066,978	9,440,089	10,085,559	115,719,044
14	OS III		3,679,704	3,583,791	3,277,776	3,352,980	3,542,604	3,870,111	43,632,239
15	OS	TOTAL	13,407,864	13,116,827	12,198,195	12,419,958	12,982,693	13,955,670	159,351,283
16	TOTAL RETAIL SALES		1,226,788,792	1,215,737,169	1,063,536,619	947,805,509	824,890,414	897,433,970	11,768,265,165
17	RE	C2S	40,401,461	40,828,680	36,329,486	31,737,898	29,746,677	33,722,060	404,900,190
18	TOTAL SALES		1,267,190,253	1,256,565,849	1,099,866,104	979,543,407	854,637,090	931,156,029	12,173,165,354
19	COMPANY USE		1,777,245	1,882,796	1,642,377	1,256,513	1,123,612	1,828,681	20,448,356
20	LOSSES		93,858,441	92,076,744	89,043,917	53,820,812	40,415,734	48,651,309	717,646,375
21	SUPPLY		1,362,825,938	1,350,525,388	1,170,552,398	1,034,620,731	896,176,436	981,636,020	12,911,260,086

22 **Major Accounts is the combination of Rates RTP, SBS and CSA.

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide a description of how the coincident and noncoincident demands for the test year were developed. Include an explanation of how the demands at the meter for each class were developed and how they were expanded from the meter level to the generation level. Provide the workpapers for the actual calculations. If a methodology other than the application of ratios of class' coincident and non coincident load to actual MWH sales is used to derive projected demands, provide justification for the use of the methodology.

Type of Data Shown:
X Projected Test Year Ended 12/31/14
__ Prior Year Ended 12/31/13
__ Historical Year Ended 12/31/09
Witness: J. I. Thompson, M. T. O'Sheasy

KW - TEST YEAR

(1) Line No.	(2) Rate	(3) Level	(4) Jan-14	(5) Feb-14	(6) Mar-14	(7) Apr-14	(8) May-14	(9) Jun-14
1	RS	G	1,298,803	1,200,103	987,797	776,282	1,149,214	1,251,877
2	RSVP	G	23,694	24,792	27,912	26,110	28,488	35,827
3	RESIDENTIAL	TOTAL	1,322,498	1,224,895	1,015,710	802,392	1,177,702	1,287,704
4	GS	G	53,209	54,786	43,190	50,558	58,318	59,230
5		F	2	1	2	2	0	0
6	GS	TOTAL	53,211	54,786	43,192	50,560	58,319	59,230
7	GSD/GSDT	G	344,106	337,662	328,400	451,845	495,055	496,149
8		F	1,668	1,662	1,557	2,073	2,126	2,874
9		E	103	72	70	113	127	114
10	GSD/GSDT	TOTAL	345,876	339,396	330,027	454,030	497,308	499,137
11	LP	G	48,772	46,038	43,428	77,211	70,399	71,812
12		F	11,155	10,201	10,134	14,445	15,140	13,920
13		E	498	473	441	551	632	545
14		C2	1,214	974	975	2,475	2,475	2,437
15	LP	TOTAL	61,639	57,687	54,978	94,682	88,646	88,714
16	LPT	G	45,158	45,798	33,902	59,854	32,936	50,239
17		F	22,622	20,601	20,749	28,976	31,242	29,219
18		ES	3,890	3,908	3,258	4,385	4,820	4,946
19		E	13,747	13,163	12,231	17,242	19,783	20,666
20		C2S	30,324	28,277	26,982	41,608	48,161	46,915
21		C2	1,054	160	1,119	1,320	1,246	1,008
22		B2S	31,833	29,050	28,229	40,663	40,353	40,922
23	LPT	TOTAL	148,627	140,958	126,470	194,049	178,541	193,915
24	LP/LPT	TOTAL	210,266	198,645	181,448	288,731	267,187	282,629

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide a description of how the coincident and noncoincident demands for the test year were developed. Include an explanation of how the demands at the meter for each class were developed and how they were expanded from the meter level to the generation level. Provide the workpapers for the actual calculations. If a methodology other than the application of ratios of class' coincident and non coincident load to actual MWH sales is used to derive projected demands, provide justification for the use of the methodology.

Type of Data Shown:
X Projected Test Year Ended 12/31/14
__ Prior Year Ended 12/31/13
__ Historical Year Ended 12/31/09
Witness: J. I. Thompson, M. T. O'Sheasy

KW - TEST YEAR

(1) Line No.	(2) Rate	(3) Level	(4) Jul-14	(5) Aug-14	(6) Sep-14	(7) Oct-14	(8) Nov-14	(9) Dec-14	(10) 12CP	(11) MAX NCPKW
1	RS	G	1,220,540	1,211,959	1,136,801	1,020,040	698,207	1,185,737	1,094,780	1,387,147
2	RSVP	G	30,530	31,972	29,627	24,518	22,326	30,067	27,989	45,961
3	RESIDENTIAL	TOTAL	1,251,071	1,243,931	1,166,428	1,044,558	720,533	1,215,804	1,122,769	
4	GS	G	68,650	62,537	62,316	54,089	38,646	52,392	54,827	74,003
5		F	1	1	0	0	0	3	1	8
6	GS	TOTAL	68,650	62,538	62,316	54,089	38,646	52,395	54,828	
7	GSD/GSDT	G	551,030	539,158	521,810	479,037	415,545	330,569	440,864	555,538
8		F	2,965	2,458	2,312	2,277	2,743	1,655	2,198	3,677
9		E	123	125	225	197	241	129	137	
10	GSD/GSDT	TOTAL	554,118	541,742	524,347	481,511	418,528	332,353	443,198	
11	LP	G	81,424	78,528	80,124	80,768	76,416	45,293	68,684	89,791
12		F	15,476	17,028	16,303	16,044	15,204	10,355	13,784	20,025
13		E	669	557	632	581	552	461	549	
14		C2	2,810	2,497	2,575	2,753	2,719	313	2,018	
15	LP	TOTAL	100,379	98,610	99,633	100,146	94,892	56,423	83,036	
16	LPT	G	60,631	65,495	65,940	62,156	81,229	41,860	53,766	81,161
17		F	32,268	32,460	31,763	30,806	31,006	21,291	27,750	37,319
18		ES	5,164	5,039	4,610	4,485	3,972	3,584	4,338	
19		E	21,060	22,013	21,800	20,768	17,396	11,663	17,628	
20		C2S	51,911	52,900	50,303	47,865	42,976	30,199	41,535	
21		C2	1,116	1,124	1,191	1,020	1,422	1,175	1,080	
22		B2S	44,115	49,970	42,276	41,062	34,740	27,033	37,520	
23	LPT	TOTAL	216,265	229,001	217,881	208,161	212,740	136,804	183,618	
24	LP/LPT	TOTAL	316,644	327,612	317,515	308,306	307,632	193,227	266,653	

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide a description of how coincident and noncoincident demands for the test year were developed. Include an explanation of how the demands at the meter for each class were developed and how they were expanded from the meter level to the generation level. Provide the workpapers for the actual calculations. If a methodology other than the application of ratios of class' coincident and non coincident load to actual MWH sales is used to derive projected demands, provide justification for the use of the methodology.

Type of Data Shown:
X Projected Test Year Ended 12/31/14
__ Prior Year Ended 12/31/13
__ Historical Year Ended 12/31/09
Witness: J. I. Thompson, M. T. O'Sheasy

KW - TEST YEAR

(1) Line No.	(2) Rate	(3) Level	(4) Jan-14	(5) Feb-14	(6) Mar-14	(7) Apr-14	(8) May-14	(9) Jun-14
1	RTP	G	756	693	667	880	866	804
2		F	45,407	32,270	42,003	48,880	52,733	46,545
3		E	4,155	3,715	3,650	4,714	1,410	4,410
4		C2S	43,686	40,023	18,664	51,333	34,437	26,606
5		C2	29,721	26,320	29,360	30,716	28,291	27,775
6	RTP	TOTAL	123,724	103,022	94,345	136,323	117,737	106,140
7	SBS	F	0	0	0	34,187	0	0
8		C2	0	0	0	0	1,353	0
9		B2S	305	890	238	237	334	577
10	SBS	TOTAL	305	890	238	34,425	1,687	577
11	CSA	F	4,776	4,754	4,424	4,236	4,457	4,434
12	MAJOR ACCTS**	TOTAL	128,805	108,665	99,007	174,984	123,681	111,152
13	OS I&II		8,046	11,022	8,761	0	0	0
14	OS III		4,259	3,979	4,102	4,957	4,973	4,388
15	OS	TOTAL	12,305	15,001	12,863	4,957	4,973	4,388
16	TOTAL RETAIL SALES		2,072,960	1,941,389	1,682,246	1,775,653	2,129,370	2,244,240
17	RE	C2S	86,997	84,058	68,137	62,255	72,472	81,379
18	TOTAL SALES		2,159,957	2,025,446	1,750,383	1,837,909	2,201,842	2,325,619
19	COMPANY USE							
20	LOSSES		211,043	200,554	141,617	128,091	191,158	255,381
21	SUPPLY		2,371,000	2,226,000	1,892,000	1,966,000	2,393,000	2,581,000

22 **Major Accounts is the combination of Rates RTP, SBS and CSA.

Supporting Schedules: Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide a description of how the coincident and noncoincident demands for the test year were developed. Include an explanation of how the demands at the meter for each class were developed and how they were expanded from the meter level to the generation level. Provide the workpapers for the actual calculations. If a methodology other than the application of ratios of class' coincident and non coincident load to actual MWH sales is used to derive projected demands, provide justification for the use of the methodology.

Type of Data Shown:
X Projected Test Year Ended 12/31/14
__ Prior Year Ended 12/31/13
___ Historical Year Ended 12/31/09
Witness: J. I. Thompson, M. T. O'Sheasy

KW - TEST YEAR

(1) Line No.	(2) Rate	(3) Level	(4) Jul-14	(5) Aug-14	(6) Sep-14	(7) Oct-14	(8) Nov-14	(9) Dec-14	(10) 12CP	(11) MAX NCPKW
1	RTP	G	2,493	2,702	897	2,163	1,031	788	1,228	4,949
2		F	49,962	46,055	45,043	55,441	53,338	37,044	46,210	100,388
3		E	4,909	5,043	4,613	4,081	4,805	4,644	4,179	
4		C2S	25,128	36,969	29,939	33,946	63,659	34,218	36,550	
5		C2	27,680	26,857	32,505	26,421	37,213	27,635	29,208	
6	RTP	TOTAL	110,172	117,626	112,998	122,051	160,046	104,328	117,376	
7	SBS	F	0	0	0	0	59,904	0	7,841	28,958
8		C2	0	0	0	0	788	0	178	
9		B2S	0	653	0	0	287	312	319	
10	SBS	TOTAL	0	653	0	0	60,977	312	8,339	
11	CSA	F	4,927	4,972	4,991	4,392	5,769	4,973	4,759	5,294
12	MAJOR ACCTS**	TOTAL	115,099	123,251	117,989	126,444	226,792	109,613	130,473	
13	OS I&II		0	0	0	0	14,536	4,327	3,891	31,001
14	OS III		4,712	5,000	5,014	4,603	5,992	4,979	4,747	4,813
15	OS	TOTAL	4,712	5,000	5,014	4,603	20,529	9,307	8,638	35,814
16	TOTAL RETAIL SALES		2,310,295	2,304,073	2,193,608	2,019,511	1,732,660	1,912,699	2,026,559	
17	RE	C2S	82,304	84,663	78,089	72,489	58,146	77,850	75,737	
18	TOTAL SALES		2,392,598	2,388,736	2,271,698	2,092,000	1,790,806	1,990,549	2,102,295	
19	COMPANY USE									
20	LOSSES		249,402	236,264	210,302	196,000	101,194	161,451	190,205	
21	SUPPLY		2,642,000	2,625,000	2,482,000	2,288,000	1,892,000	2,152,000	2,292,500	

22 **Major Accounts is the combination of Rates RTP, SBS and CSA.

Supporting Schedules: Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide a description of how the coincident and noncoincident demands for the test year were developed. Include an explanation of how the demands at the meter for each class were developed and how they were expanded from the meter level to the generation level. Provide the workpapers for the actual calculations. If a methodology other than the application of ratios of class' coincident and non coincident load to actual MWH sales is used to derive projected demands, provide justification for the use of the methodology.

Type of Data Shown:
X Projected Test Year Ended 12/31/14
__ Prior Year Ended 12/31/13
___ Historical Year Ended 12/31/09
Witness: J. I. Thompson, M. T. O'Sheasy

GULF POWER COMPANY
12 MONTHS ENDING DECEMBER 31, 2014
12/13 DEMAND ALLOCATION
12-MCP DEMAND ALLOCATORS BY RATE CLASS

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
LINE NO.	DESCRIPTION	TOTAL ELECTRIC SYSTEM	RATE CLASS RESIDENTIAL	RATE CLASS GS	RATE CLASS GSD/GSDT	RATE CLASS LP/LPT	RATE CLASS MAJOR ACCTS	RATE CLASS OS	TOTAL RETAIL SERVICE	WHOLESALE	UNIT POWER SALES
	LEVEL 5										
	COMMON										
1	SALES	1,748,776	1,122,769	54,827	440,864	120,450	1,228	8,638	1,748,776	0	0
2	LOSSES	66,259	42,539	2,077	16,704	4,565	47	327	66,259	0	0
3	INTO	1,815,035	1,165,308	56,904	457,568	125,015	1,275	8,965	1,815,035	0	0
	CUSTOMER SUBS										
4	SALES	0	0	0	0	0	0	0	0	0	0
5	LOSSES	0	0	0	0	0	0	0	0	0	0
6	INTO	0	0	0	0	0	0	0	0	0	0
	TOTAL LEVEL 5										
7	SALES	1,748,776	1,122,769	54,827	440,864	120,450	1,228	8,638	1,748,776	0	0
8	LOSSES	66,259	42,539	2,077	16,704	4,565	47	327	66,259	0	0
9	INTO	1,815,035	1,165,308	56,904	457,568	125,015	1,275	8,965	1,815,035	0	0
	LEVEL 4										
10	OUT	1,815,035	1,165,308	56,904	457,568	125,015	1,275	8,965	1,815,035	0	0
11	SALES	102,543	0	1	2,198	41,534	58,810	0	102,543	0	0
12	LOSSES	73,152	44,454	2,171	17,539	6,354	2,292	342	73,152	0	0
13	INTO	1,990,730	1,209,762	59,076	477,305	172,903	62,377	9,307	1,990,730	0	0

14 Rate Class Residential as shown in the Cost of Service Study is the combination of Rates RS and RSVP.
15 Rate Class Major Accounts as shown in the Cost of Service Study is the combination of Rates RTP, SBS and CSA.

Supporting Schedules: Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide a description of how the coincident and noncoincident demands for the test year were developed. Include an explanation of how the demands at the meter for each class were developed and how they were expanded from the meter level to the generation level. Provide the workpapers for the actual calculations. If a methodology other than the application of ratios of class' coincident and non coincident load to actual MWH sales is used to derive projected demands, provide justification for the use of the methodology.

Type of Data Shown:
X Projected Test Year Ended 12/31/14
__ Prior Year Ended 12/31/13
__ Historical Year Ended 12/31/09
Witness: J. I. Thompson, M. T. O'Sheasy

GULF POWER COMPANY
12 MONTHS ENDING DECEMBER 31, 2014
12/13 DEMAND ALLOCATION
12-MCP DEMAND ALLOCATORS BY RATE CLASS

(1) LINE NO.	(2) DESCRIPTION	(3) TOTAL ELECTRIC SYSTEM	(4) RATE CLASS RESIDENTIAL	(5) RATE CLASS GS	(6) RATE CLASS GSD/GSDT	(7) RATE CLASS LP/LPT	(8) RATE CLASS MAJOR ACCTS	(9) RATE CLASS OS	(10) TOTAL RETAIL SERVICE	(11) WHOLESALE	(12) UNIT POWER SALES
	LEVEL 3										
	COMMON										
1	OUT	1,990,730	1,209,762	59,076	477,305	172,903	62,377	9,307	1,990,730	0	0
2	SALES	54,977	0	0	137	21,275	33,565	0	54,977	0	0
3	LOSSES	9,004	5,324	260	2,101	855	423	41	9,004	0	0
4	INTO	2,054,711	1,215,086	59,336	479,543	195,033	96,365	9,348	2,054,711	0	0
	CUSTOMER SUBS										
5	SALES	158,160	0	0	0	45,873	36,550	0	82,423	75,737	0
6	LOSSES	696	0	0	0	202	161	0	363	333	0
7	INTO	158,856	0	0	0	46,075	36,711	0	82,786	76,070	0
	TOTAL LEVEL 3										
8	OUT	1,990,730	1,209,762	59,076	477,305	172,903	62,377	9,307	1,990,730	0	0
9	SALES	213,137	0	0	137	67,148	70,115	0	137,400	75,737	0
10	LOSSES	9,700	5,324	260	2,101	1,057	584	41	9,367	333	0
11	INTO	2,213,587	1,215,086	59,336	479,543	241,108	133,076	9,348	2,137,497	76,070	0
	LEVEL 2										
12	OUT	2,213,567	1,215,086	59,336	479,543	241,108	133,076	9,348	2,137,497	76,070	0
13	SALES	37,839	0	0	0	37,520	319	0	37,839	0	0
14	LOSSES	41,094	22,177	1,083	8,753	5,086	2,435	171	39,705	1,389	0
15	INTO	2,292,500	1,237,263	60,419	488,296	283,714	135,830	9,519	2,215,041	77,459	0
	LEVEL 1										
16	OUT	2,292,500	1,237,263	60,419	488,296	283,714	135,830	9,519	2,215,041	77,459	0

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide a description of how the coincident and noncoincident demands for the test year were developed. Include an explanation of how the demands at the meter for each class were developed and how they were expanded from the meter level to the generation level. Provide the workpapers for the actual calculations. If a methodology other than the application of ratios of class' coincident and non coincident load to actual MWH sales is used to derive projected demands, provide justification for the use of the methodology.

Type of Data Shown:
X Projected Test Year Ended 12/31/14
__ Prior Year Ended 12/31/13
__ Historical Year Ended 12/31/09
Witness: J. I. Thompson, M. T. O'Sheasy

GULF POWER COMPANY
12 MONTHS ENDING DECEMBER 31, 2014
12/13 DEMAND ALLOCATION
NCP DEMAND ALLOCATORS BY RATE CLASS

(1) LINE NO.	(2) DESCRIPTION	(3) TOTAL ELECTRIC SYSTEM	(4) RATE CLASS RESIDENTIAL	(5) RATE CLASS GS	(6) RATE CLASS GSD/GSDT	(7) RATE CLASS LP/LPT	(8) RATE CLASS MAJOR ACCTS	(9) RATE CLASS OS	(10) TOTAL RETAIL SERVICE	(11) WHOLESALE	(12) UNIT POWER SALES
	LEVEL 5										
	COMMON										
1	SALES	2,274,364	1,433,108	74,003	555,538	170,952	4,949	35,814	2,274,364	0	0
2	LOSSES	86,173	54,298	2,804	21,049	6,477	188	1,357	86,173	0	0
3	INTO	2,360,537	1,487,406	76,807	576,587	177,429	5,137	37,171	2,360,537	0	0
	CUSTOMER SUBS										
4	SALES	0	0	0	0	0	0	0	0	0	0
5	LOSSES	0	0	0	0	0	0	0	0	0	0
6	INTO	0	0	0	0	0	0	0	0	0	0
	TOTAL LEVEL 5										
7	SALES	2,274,364	1,433,108	74,003	555,538	170,952	4,949	35,814	2,274,364	0	0
8	LOSSES	86,173	54,298	2,804	21,049	6,477	188	1,357	86,173	0	0
9	INTO	2,360,537	1,487,406	76,807	576,587	177,429	5,137	37,171	2,360,537	0	0
	LEVEL 4										
10	OUT	2,360,537	1,487,406	76,807	576,587	177,429	5,137	37,171	2,360,537	0	0
11	SALES	195,669	0	8	3,677	57,344	134,640	0	195,669	0	0
12	LOSSES	97,515	56,742	2,930	22,136	8,956	5,339	1,418	97,515	0	0
13	INTO	2,653,721	1,544,148	79,745	602,400	243,729	145,110	38,589	2,653,721	0	0

14 Rate Class Residential as shown in the Cost of Service Study is the combination of Rates RS and RSVP.
15 Rate Class Major Accounts as shown in the Cost of Service Study is the combination of Rates RTP, SBS and CSA.

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide a description of how the coincident and noncoincident demands for the test year were developed. Include an explanation of how the demands at the meter for each class were developed and how they were expanded from the meter level to the generation level. Provide the workpapers for the actual calculations. If a methodology other than the application of ratios of class' coincident and non coincident load to actual MWH sales is used to derive projected demands, provide justification for the use of the methodology.

Type of Data Shown:
X Projected Test Year Ended 12/31/14
__ Prior Year Ended 12/31/13
__ Historical Year Ended 12/31/09
Witness: J. I. Thompson, M. T. O'Sheasy

GULF POWER COMPANY
12 MONTHS ENDING DECEMBER 31, 2014
12/13 DEMAND ALLOCATION
NCP DEMAND ALLOCATORS BY RATE CLASS

(1) LINE NO.	(2) DESCRIPTION LEVEL 3	(3) TOTAL ELECTRIC SYSTEM	(4) RATE CLASS RESIDENTIAL	(5) RATE CLASS GS	(6) RATE CLASS GSD/GSDT	(7) RATE CLASS LP/LPT	(8) RATE CLASS MAJOR ACCTS	(9) RATE CLASS OS	(10) TOTAL RETAIL SERVICE	(11) WHOLESALE	(12) UNIT POWER SALES
1	COMMON										
2	OUT	2,653,721	1,544,148	79,745	602,400	243,729	145,110	38,589	2,653,721	0	0
3	SALES	0	0	0	0	0	0	0	0	0	0
4	LOSSES	11,679	6,796	351	2,651	1,073	638	170	11,679	0	0
5	INTO	2,665,400	1,550,944	80,096	605,051	244,802	145,748	38,759	2,665,400	0	0
6	CUSTOMER SUBS										
7	SALES	0	0	0	0	0	0	0	0	0	0
8	LOSSES	0	0	0	0	0	0	0	0	0	0
9	INTO	0	0	0	0	0	0	0	0	0	0
10	TOTAL LEVEL 3										
11	OUT	2,653,721	1,544,148	79,745	602,400	243,729	145,110	38,589	2,653,721	0	0
12	SALES	0	0	0	0	0	0	0	0	0	0
13	LOSSES	11,679	6,796	351	2,651	1,073	638	170	11,679	0	0
14	INTO	2,665,400	1,550,944	80,096	605,051	244,802	145,748	38,759	2,665,400	0	0
15	LEVEL 2										
16	OUT	2,665,400	1,550,944	80,096	605,051	244,802	145,748	38,759	2,665,400	0	0
17	SALES	0	0	0	0	0	0	0	0	0	0
18	LOSSES	48,650	28,309	1,462	11,044	4,468	2,660	707	48,650	0	0
19	INTO	2,714,050	1,579,253	81,558	616,095	249,270	148,408	39,466	2,714,050	0	0
20	LEVEL 1										
21	OUT	2,714,050	1,579,253	81,558	616,095	249,270	148,408	39,466	2,714,050	0	0

Schedule E-12 | ADJUSTMENT TO TEST YEAR REVENUE | Page 1 of 2

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide a schedule showing the calculation of the adjustment by rate class to the test year amount of unbilled revenue for the effect of the proposed rate increase. The calculation of test year unbilled revenue at present rates is provided in Schedule C-11.

Type of Data Shown:
_X_ Projected Test Year Ending 12/31/14
___ Prior Year Ended 12/31/13
___ Historical Year Ended 12/31/12
Witness: J. I. Thompson

Allocation Method: 12MCP - 1/13th kWh - Minimum Distribution System

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
		Sales of Electricity (excluding unbilled)			Unbilled Sales			
						Base Revenues ($000's)		
Line No.	Rate Class	Proposed Base Revenue ($000's)	MWH	Per Unit $/MWH (3)/(4)	MWH	Proposed (5)*(6)	Present	Adjustment (7)-(8)
1	RESIDENTIAL	$339,748	5,258,939	$65	5,506	$358	$412	($54)
2	GS	$22,767	290,975	$78	308	$24	$22	$2
3	GSD/GSDT	$115,803	2,730,851	$42	2,837	$119	$106	$13
4	LP/LPT	$40,960	1,231,341	$33	2,313	$76	$63	$13
5	MAJOR ACCTS	$36,022	1,477,619	$24	-	$0	$0	$0
6	OS	$15,729	153,368	$103	222	$23	$16	$7
7	TOTAL	$571,029	11,143,093	$51	11,186	$570	$619	($19)

90

Supporting Schedules: E-13c

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide a schedule showing the calculation of the adjustment by rate class to the test year amount of unbilled revenue for the effect of the proposed rate increase. The calculation of test year unbilled revenue at present rates is provided in Schedule C-11.

Type of Data Shown:
X Projected Test Year Ending 12/31/14
___ Prior Year Ended 12/31/13
___ Historical Year Ended 12/31/12
Witness: J. I. Thompson

Allocation Method: 12MCP - 1/13th kWh

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
		Sales of Electricity (excluding unbilled)			Unbilled Sales			
						Base Revenues ($000's)		
Line No.	Rate Class	Proposed Base Revenue ($000's)	MWH	Per Unit $/MWH (3)/(4)	MWH	Proposed (5)*(6)	Present	Adjustment (7)-(8)
1	RESIDENTIAL	$339,748	5,258,939	$65	5,506	$358	$412	($54)
2	GS	$22,760	290,975	$78	308	$24	$22	$2
3	GSD/GSDT	$115,810	2,730,851	$42	2,837	$119	$106	$13
4	LP/LPT	$40,960	1,231,341	$33	2,313	$76	$63	$13
5	MAJOR ACCTS	$36,022	1,477,619	$24	-	$0	$0	$0
6	OS	$15,729	153,368	$103	222	$23	$16	$7
7	TOTAL	$571,029	11,143,093	$51	11,186	$570	$619	($19)

Supporting Schedules: E-13c

Recap Schedules:

Schedule E-13a | REVENUE FROM SALE OF ELECTRICITY BY RATE SCHEDULE | Page 1 of 1

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Compare jurisdictional revenue excluding service charges by rate schedule under present and proposed rates for the test year. If any customers are to be transferred from one schedule to another, the revenue and billing determinant information shall be shown separately for the transfer group and not be included under either the new or old classification.

($000's)

Type of Data Shown:
_X_ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
___ Historical Year Ended 12/31/12
Witness: J. I. Thompson

(1) Line No.	(2) Rate	(3) Base Revenues at Present Rates	(4) Base Revenues at Proposed Rates	(5) Increase Dollars (4)-(3)	(6) Increase Percent (5)/(3)
1	RESIDENTIAL	$296,477	$339,748	$43,271	14.60%
2	GS	$20,514	$22,767	$2,253	10.98%
3	GSD/GSDT	$102,678	$115,803	$13,125	12.78%
4	LP/LPT	$33,870	$40,960	$7,090	20.93%
5	MAJOR ACCTS	$29,452	$36,022	$6,570	22.31%
6	OS	$14,880	$15,729	$849	5.71%
7	TOTAL:	$497,871	$571,029	$73,158	14.69%

Supporting Schedules: E-13c, E-13d

Recap Schedules: E-8

Schedule E-13b | REVENUES BY RATE SCHEDULE - SERVICE CHARGES (ACCOUNT 451) | Page 1 of 3

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide a schedule of revenues from all service charges (initial connection, etc.) under present and proposed rates.

Type of Data Shown:
_X_ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
___ Historical Year Ended 12/31/12
Witness: J. I. Thompson

(1) Line No.	(2) Rate Schedule	(3) Type of Service Charge*	(4) Number of Transactions	(5) Present Charge	(6) Proposed Charge	(7) Revenues at Present Charges (4) x (5)	(8) Revenues at Proposed Charges (4) x (6)	(9) Increase Dollars (8) - (7)	(10) Increase Percent (%)
1	RESIDENTIAL	1	2,847	$27.00	$27.00	$76,869	$76,869	$0	0.0%
2		2	99,854	$27.00	$27.00	$2,696,058	$2,696,058	$0	0.0%
3		3	33,532	$35.00	$60.00	$1,173,620	$2,011,920	$838,300	71.4%
4		4	2,099	$55.00	$80.00	$115,445	$167,920	$52,475	45.5%
5		5	198	$95.00	$100.00	$18,810	$19,800	$990	5.3%
6		6	8,031	$20.00	$30.00	$160,620	$240,930	$80,310	50.0%
7		7	0	$110.00	$110.00	$0	$0	$0	0.0%
8		8	505	$75.00	$75.00	$37,875	$37,875	$0	0.0%
9		9	800	$25.00	$25.00	$20,000	$20,000	$0	0.0%
10		10	6,875	$30.00	$30.00	$206,250	$206,250	$0	0.0%
11		11	800	$40.00	$40.00	$32,000	$32,000	$0	0.0%
12			155,541			$4,537,547	$5,509,622	$972,075	21.4%

*1=Connection of Initial Service; 2=Connection of Existing Service; 3=Restoration of Service (After Violation of Rules); 4=Restoration of Service After Hours (After Violation of Rules); 5=Restoration of Service at Pole (After Violation of Rules); 6=Premise Visit; 7=Connection of Temporary Service; 8=Investigation of Unauthorized Use; 9=Returned Check Charge ≤ $50; 10=Returned Check Charge > $50, ≤ $300; 11=Returned Check Charge > $300.

Supporting Schedules: E-8

Recap Schedules: E-5

Schedule E-13b | REVENUES BY RATE SCHEDULE - SERVICE CHARGES (ACCOUNT 451) | Page 2 of 3

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide a schedule of revenues from all service charges (initial connection, etc.) under present and proposed rates.

Type of Data Shown:
X Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
___ Historical Year Ended 12/31/12
Witness: J. I. Thompson

(1) Line No.	(2) Rate Schedule	(3) Type of Service Charge*	(4) Number of Transactions	(5) Present Charge	(6) Proposed Charge	(7) Revenues at Present Charges (4) x (5)	(8) Revenues at Proposed Charges (4) x (6)	(9) Increase Dollars (8) - (7)	(10) Increase Percent (%)
1	GS	1	479	$27.00	$50.00	$12,933	$23,950	$11,017	85.2%
2		2	3,099	$27.00	$50.00	$83,673	$154,950	$71,277	85.2%
3		3	891	$35.00	$60.00	$31,185	$53,460	$22,275	71.4%
4		4	20	$55.00	$80.00	$1,100	$1,600	$500	45.5%
5		5	19	$95.00	$100.00	$1,805	$1,900	$95	5.3%
6		6	1,206	$20.00	$30.00	$24,120	$36,180	$12,060	50.0%
7		7	0	$110.00	$110.00	$0	$0	$0	0.0%
8		8	24	$75.00	$75.00	$1,800	$1,800	$0	0.0%
9		9	25	$25.00	$25.00	$625	$625	$0	0.0%
10		10	145	$30.00	$30.00	$4,350	$4,350	$0	0.0%
11		11	25	$40.00	$40.00	$1,000	$1,000	$0	0.0%
12			5,933			$162,591	$279,815	$117,224	72.1%

*1=Connection of Initial Service; 2=Connection of Existing Service; 3=Restoration of Service (After Violation of Rules); 4=Restoration of Service After Hours (After Violation of Rules); 5=Restoration of Service at Pole (After Violation of Rules); 6=Premise Visit; 7=Connection of Temporary Service; 8=Investigation of Unauthorized Use; 9=Returned Check Charge ≤ $50; 10=Returned Check Charge > $50, ≤ $300; 11=Returned Check Charge > $300.

Supporting Schedules: E-8

Recap Schedules: E-5

Schedule E-13b | REVENUES BY RATE SCHEDULE - SERVICE CHARGES (ACCOUNT 451) | Page 3 of 3

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide a schedule of revenues from all service charges (initial connection, etc.) under present and proposed rates.

Type of Data Shown:
X Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
___ Historical Year Ended 12/31/12
Witness: J. I. Thompson

(1) Line No.	(2) Rate Schedule	(3) Type of Service Charge*	(4) Number of Transactions	(5) Present Charge	(6) Proposed Charge	(7) Revenues at Present Charges (4) x (5)	(8) Revenues at Proposed Charges (4) x (6)	(9) Increase Dollars (8) - (7)	(10) Increase Percent (%)
1	GSD/GSDT	1	64	$27.00	$50.00	$1,728	$3,200	$1,472	85.2%
2		2	1,610	$27.00	$50.00	$43,470	$80,500	$37,030	85.2%
3		3	235	$35.00	$60.00	$8,225	$14,100	$5,875	71.4%
4		4	0	$55.00	$80.00	$0	$0	$0	0.0%
5		5	52	$95.00	$100.00	$4,940	$5,200	$260	5.3%
6		6	1,113	$20.00	$30.00	$22,260	$33,390	$11,130	50.0%
7		7	0	$110.00	$110.00	$0	$0	$0	0.0%
8		8	0	$75.00	$75.00	$0	$0	$0	0.0%
9		9	25	$25.00	$25.00	$625	$625	$0	0.0%
10		10	200	$30.00	$30.00	$6,000	$6,000	$0	0.0%
11		11	25	$40.00	$40.00	$1,000	$1,000	$0	0.0%
12			3,324			$88,248	$144,015	$55,767	63.2%

*1=Connection of Initial Service; 2=Connection of Existing Service; 3=Restoration of Service (After Violation of Rules); 4=Restoration of Service After Hours (After Violation of Rules); 5=Restoration of Service at Pole (After Violation of Rules); 6=Premise Visit; 7=Connection of Temporary Service; 8=Investigation of Unauthorized Use; 9=Returned Check Charge ≤ $50; 10=Returned Check Charge > $50, ≤ $300; 11=Returned Check Charge > $300.

Supporting Schedules: E-8

Recap Schedules: E-5

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: By rate schedule, calculate revenues under present and proposed rates for the test year. If any customers are to be transferred from one schedule to another, show revenues separately for the transfer group. Correction factors are used for historic test years only. The total base revenue by class must equal that shown in Schedule E-13a. The billing units must equal those shown in Schedule E-15. PROVIDE TOTAL NUMBER OF BILLS, MWH's, AND BILLING kWh FOR EACH RATE SCHEDULE (INCLUDING STANDARD AND TIME OF USE CUSTOMERS) AND TRANSFER GROUP.

Type of Data Shown:
_X_ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
___ Historical Year Ended 12/31/12
Witness: J. I. Thompson

REVENUE CALCULATION FOR RATE SCHEDULES RS, RSVP AND FLAT-RS

(1) Line No.	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	PRESENT REVENUE CALCULATION				PROPOSED REVENUE CALCULATION			
1	BASE CHARGE (CHG)	NUMBER OF BILLS		CALCULATED REVENUES	BASE CHARGE	NUMBER OF BILLS		CALCULATED REVENUES
2	STANDARD RS:	4,426,051 BILLS @	$15.00 /BILL	$66,390,765	STANDARD RS:	4,426,051 BILLS @	$18.00 /BILL	$79,668,918
3	RSVP:	137,130 BILLS @	$15.00 /BILL	$2,056,950	RSVP:	137,130 BILLS @	$18.00 /BILL	$2,468,340
4	ENERGY/DEMAND CHG	KWH IN BLOCK			ENERGY/DEMAND CHG	KWH IN BLOCK		
5	STANDARD RS:	4,968,775,281 KWH @	$0.04313 /KWH	$214,217,018	STANDARD RS:	4,968,775,281 KWH @	$0.04884 /KWH	$242,577,305
6	RSVP: LOW	46,823,798 KWH @	$0.04313 /KWH	$2,019,510	RSVP: LOW	46,823,798 KWH @	$0.04884 /KWH	$2,286,874
7	RSVP: MEDIUM	129,677,774 KWH @	$0.04313 /KWH	$5,601,628	RSVP: MEDIUM	129,677,774 KWH @	$0.04884 /KWH	$6,343,230
8	RSVP: HIGH	31,780,858 KWH @	$0.04313 /KWH	$1,370,708	RSVP: HIGH	31,780,858 KWH @	$0.04884 /KWH	$1,552,177
9	RSVP: CRITICAL	3,389,968 KWH @	$0.04313 /KWH	$146,209	RSVP: CRITICAL	3,389,958 KWH @	$0.04884 /KWH	$165,566
10	FLAT-RS	69,209 Bills	60,291,424 KWH	$4,674,252	FLAT-RS	69,209 Bills	60,291,424 KWH	$4,674,252
11			PRESENT BASE REVENUE:	$296,477,040			PROJECTED BASE REVENUE:	$339,736,662
12							TOTAL INCREASE:	$43,259,622
13							% INCREASE:	14.59%

14 TRANSFERS FROM RATE SCHEDULE _____ TRANSFERS TO RATE SCHEDULE _____

Supporting Schedule: E-13a Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: By rate schedule, calculate revenues under present and proposed rates for the test year. If any customers are to be transferred from one schedule to another, show revenues separately for the transfer group. Correction factors are used for historic test years only. The total base revenue by class must equal that shown in Schedule E-13a. The billing units must equal those shown in Schedule E-15. PROVIDE TOTAL NUMBER OF BILLS, MWH's, AND BILLING kWh FOR EACH RATE SCHEDULE (INCLUDING STANDARD AND TIME OF USE CUSTOMERS) AND TRANSFER GROUP.

Type of Data Shown:
_X_ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
___ Historical Year Ended 12/31/12
Witness: J. I. Thompson

REVENUE CALCULATION FOR RATE SCHEDULES GS AND FLAT-GS

(1) Line No.	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	PRESENT REVENUE CALCULATION				PROPOSED REVENUE CALCULATION			
1	BASE CHARGE	NUMBER OF BILLS		CALCULATED REVENUES	BASE CHARGE	NUMBER OF BILLS		CALCULATED REVENUES
2	STANDARD GS:	348,125 BILLS @	$18.00 /BILL	$6,266,250	STANDARD GS:	348,125 BILLS @	$21.00 /BILL	$7,310,625
3	ENERGY/DEMAND CHG	KWH IN BLOCK			ENERGY/DEMAND CHG	KWH IN BLOCK		
4	STANDARD GS:	288,830,504 KWH @	$0.04884 /KWH	$14,106,482	STANDARD GS:	288,830,504 KWH @	$0.05300 /KWH	$15,308,017
5	FLAT-GS	1,762 Bills	2,144,430 KWH	$141,506		1,762 Bills	2,144,430 KWH	$141,506
6			PRESENT BASE REVENUE :	$20,514,238			PROJECTED BASE REVENUE :	$22,760,148
7							TOTAL INCREASE:	$2,245,910
8							% INCREASE:	10.95%

9 TRANSFERS FROM RATE SCHEDULE _____ TRANSFERS TO RATE SCHEDULE _____

Supporting Schedule: E-13a Recap Schedules:

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Schedule E-13c | BASE REVENUE BY RATE SCHEDULE - CALCULATIONS | Page 3 of 15

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: By rate schedule, calculate revenues under present and proposed rates for the test year. If any customers are to be transferred from one schedule to another, show revenues separately for the transfer group. Correction factors are used for historic test years only. The total base revenue by class must equal that shown in Schedule E-13a. The billing units must equal those shown in Schedule E-15. PROVIDE TOTAL NUMBER OF BILLS, MWH's, AND BILLING kWh FOR EACH RATE SCHEDULE (INCLUDING STANDARD AND TIME OF USE CUSTOMERS) AND TRANSFER GROUP.

Type of Data Shown:
X Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
___ Historical Year Ended 12/31/12
Witness: J. I. Thompson

REVENUE CALCULATION FOR RATE SCHEDULES GSD, GSDT, AND GSTOU

(1) Line No.	(2)	(3)		(4)		(5)	(6)	(7)		(8)		(9)
	PRESENT REVENUE CALCULATION - GSD, GSDT, AND GSTOU						PROPOSED REVENUE CALCULATION - GSD, GSDT, AND GSTOU					
1	BASE CHARGE	NUMBER OF BILLS				CALCULATED REVENUES	BASE CHARGE	NUMBER OF BILLS				CALCULATED REVENUES
2	STANDARD :	149,634	BILLS @	$44.00	/BILL	$6,583,896	STANDARD :	149,634	BILLS @	$44.00	/BILL	$6,583,896
3	TOU :	1,222	BILLS @	$44.00	/BILL	$53,768	TOU :	1,222	BILLS @	$44.00	/BILL	$53,768
4	GSTOU :	7,527	BILLS @	$44.00	/BILL	$331,188	GSTOU :	7,527	BILLS @	$44.00	/BILL	$331,188
5	DEMAND CHARGE	BILLING KW IN BLOCK					DEMAND CHARGE	BILLING KW IN BLOCK				
6	STANDARD :	7,724,231	KW @	$5.95	/KW	$45,959,174	STANDARD :	7,724,231	KW @	$6.84	/KW	$52,833,740
7	TOU : MAX DEMAND	96,690	KW @	$2.82	/KW	$272,666	TOU : MAX DEMAND	96,690	KW @	$3.24	/KW	$313,276
8	TOU : ON-PEAK	82,426	KW @	$3.18	/KW	$262,115	TOU : ON-PEAK	82,426	KW @	$3.66	/KW	$301,679
9	ENERGY CHARGE	KWH IN BLOCK					ENERGY CHARGE	KWH IN BLOCK				
10	STANDARD :	2,495,777,909	KWH @	$0.01525	/KWH	$38,060,613	STANDARD :	2,495,777,909	KWH @	$0.01749	/KWH	$43,651,156
11	TOU : ON-PEAK	7,022,143	KWH @	$0.01525	/KWH	$107,088	TOU : ON-PEAK	7,022,143	KWH @	$0.01749	/KWH	$122,817
12	TOU : OFF-PEAK	17,556,905	KWH @	$0.01525	/KWH	$267,743	TOU : OFF-PEAK	17,556,905	KWH @	$0.01749	/KWH	$307,070
13	TOU : SUM ON-PK	1,988,843	KWH @	$0.16391	/KWH	$325,991	TOU : SUM ON-PK	1,988,843	KWH @	$0.18691	/KWH	$371,735
14	TOU : SUM INTER	1,892,016	KWH @	$0.06119	/KWH	$115,772	TOU : SUM INTER	1,892,016	KWH @	$0.06978	/KWH	$132,025
15	TOU : SUM OFF-PK	8,676,717	KWH @	$0.02545	/KWH	$220,822	TOU : SUM OFF-PK	6,676,717	KWH @	$0.02902	/KWH	$251,798
16	TOU : WINTER	16,994,123	KWH @	$0.03562	/KWH	$676,571	TOU : WINTER	16,994,123	KWH @	$0.04062	/KWH	$771,541
17	VOLTAGE DISCOUNTS						VOLTAGE DISCOUNTS					
16	STANDARD : PRIMARY						STANDARD : PRIMARY					
19		32,671	KW @	($0.29)	/KW	($9,475)		32,671	KW @	($0.39)	/KW	($12,742)
20		32,671	KW @	($0.0595)	/KW	($1,944)		32,671	KW @	($0.0684)	/KW	($2,235)
21		11,677,565	KWH @	($0.0001525)	/KWH	($1,781)		11,677,555	KWH @	($0.0001749)	/KWH	($2,042)
22				SUBTOTAL BASE REVENUE:		$93,224,207				SUBTOTAL BASE REVENUE:		$106,008,670

23 TRANSFERS FROM RATE SCHEDULE____ TRANSFERS TO RATE SCHEDULE _____

Supporting Schedule: E-13a Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: By rate schedule, calculate revenues under present and proposed rates for the test year. If any customers are to be transferred from one schedule to another, show revenues separately for the transfer group. Correction factors are used for historic test years only. The total base revenue by class must equal that shown in Schedule E-13a. The billing units must equal those shown in Schedule E-15. PROVIDE TOTAL NUMBER OF BILLS, MWH's, AND BILLING kWh FOR EACH RATE SCHEDULE (INCLUDING STANDARD AND TIME OF USE CUSTOMERS) AND TRANSFER GROUP.

Type of Data Shown:
X Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
___ Historical Year Ended 12/31/12
Witness: J. I. Thompson

REVENUE CALCULATION FOR RATE SCHEDULES GSD, GSDT, AND GSTOU

(1) Line No.	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	TRANSFERS FROM RATE SCHEDULE GSD				TRANSFERS TO RATE SCHEDULE GS			
1	BASE CHARGE	NUMBER OF BILLS		CALCULATED REVENUES	BASE CHARGE	NUMBER OF BILLS		CALCULATED REVENUES
2	STANDARD :	51,099 BILLS @	$44.00 /BILL	$2,248,356	STANDARD :	51,099 BILLS @	$21.00 /BILL	$1,073,079
3	TOU :	--- BILLS @	--- /BILL	---	TOU :	--- BILLS @	--- /BILL	---
4	DEMAND CHARGE	BILLING KW IN BLOCK			DEMAND CHARGE	BILLING KW IN BLOCK		
5	STANDARD :	562,361 KW @	$5.95 /KW	$3,346,048	STANDARD :	--- KW @	--- /KW	---
6	TOU : MAX DEMAND	--- KW @	--- /KW	---	TOU : MAX DEMAND	--- KW @	--- /KW	---
7	TOU : ON-PEAK	--- KW @	--- /KW	---	TOU : ON-PEAK	--- KW @	--- /KW	---
8	ENERGY CHARGE	KWH IN BLOCK			ENERGY/DEMAND CHG	KWH IN BLOCK		
9	STANDARD :	107,509,465 KWH @	$0.01525 /KWH	$1,639,519	STANDARD :	107,509,465 KWH @	$0.05300 /KWH	$5,698,002
10	TOU : ON-PEAK	--- KWH @	--- /KWH	---	TOU : ON-PEAK	--- KWH @	--- /KWH	---
11	TOU : OFF-PEAK	--- KWH @	--- /KWH	---	TOU : OFF-PEAK	--- KWH @	--- /KWH	---
12		SUBTOTAL BASE REVENUE :		$7,233,923		SUBTOTAL BASE REVENUE :		$6,771,081

13 TRANSFERS FROM RATE SCHEDULE GSD — TRANSFERS TO RATE SCHEDULE GS

Supporting Schedule: E-13a — Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: By rate schedule, calculate revenues under present and proposed rates for the test year. If any customers are to be transferred from one schedule to another, show revenues separately for the transfer group. Correction factors are used for historic test years only. The total base revenue by class must equal that shown in Schedule E-13a. The billing units must equal those shown in Schedule E-15. PROVIDE TOTAL NUMBER OF BILLS, MWH's, AND BILLING kWh FOR EACH RATE SCHEDULE (INCLUDING STANDARD AND TIME OF USE CUSTOMERS) AND TRANSFER GROUP.

Type of Data Shown:
X Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
___ Historical Year Ended 12/31/12
Witness: J. I. Thompson

REVENUE CALCULATION FOR RATE SCHEDULES GSD, GSDT, AND GSTOU

(1) Line No.	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
		TRANSFERS FROM RATE SCHEDULE GSD				TRANSFERS TO RATE SCHEDULE LP		
1	BASE CHARGE	NUMBER OF BILLS		CALCULATED REVENUES	BASE CHARGE	NUMBER OF BILLS		CALCULATED REVENUES
2	STANDARD :	400 BILLS @	$44.00 /BILL	$17,600	STANDARD :	400 BILLS @	$250.00 /BILL	$100,000
3	TOU :	--- BILLS @	--- /BILL	---	TOU:	--- BILLS @	--- /BILL	---
4	DEMAND CHARGE	BILLING KW IN BLOCK			DEMAND CHARGE	BILLING KW IN BLOCK		
5	STANDARD :	183,388 KW @	$5.95 /KW	$1,091,159	STANDARD :	183,388 KW @	$12.23 /KW	$2,242,835
6	TOU : MAX DEMAND	--- KW @	--- /KW	---	TOU : MAX DEMAND	--- KW @	--- /KW	---
7	TOU : ON-PEAK	--- KW @	--- /KW	---	TOU : ON-PEAK	--- KW @	--- /KW	---
8	ENERGY CHARGE	KWH IN BLOCK			ENERGY CHARGE	KWH IN BLOCK		
9	STANDARD :	70,173,383 KWH @	$0.01625 /KWH	$1,070,144	STANDARD :	70,173,383 KWH @	$0.00934 /KWH	$655,419
10	TOU : ON-PEAK	--- KWH @	--- /KWH	---	TOU : ON-PEAK	--- KWH @	--- /KWH	---
11	TOU : OFF-PEAK	--- KWH @	--- /KWH	---	TOU : OFF-PEAK	--- KWH @	--- /KWH	---
12	REACTIVE CHARGE				REACTIVE CHARGE			
13	STANDARD :	--- KVARS @	--- /KVAR	---	STANDARD :	--- KVARS @	--- /KVAR	---
14	TOU :	--- KVARS @	--- /KVAR	---	TOU :	--- KVARS @	--- /KVAR	---
15	VOLTAGE DISCOUNTS				VOLTAGE DISCOUNTS			
16	STANDARD : PRIMARY	12,842 KW @	($0.29) /KW	($3,724)	STANDARD : PRIMARY	12,842 KW @	($0.55) /KW	($7,063)
17		12,842 KW @	($0.0596) /KW	($764)		12,842 KW @	($0.1223) /KW	($1,571)
18		5,867,082 KWH @	($0.0001525) /KWH	($895)		5,867,082 KWH @	($0.0000934) /KWH	($548)
19			SUBTOTAL BASE REVENUE :	$2,173,520			SUBTOTAL BASE REVENUE :	$2,989,072

20 TRANSFERS FROM RATE SCHEDULE GSD

TRANSFERS TO RATE SCHEDULE LP

Supporting Schedule: E-13a

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: By rate schedule, calculate revenues under present end proposed rates for the test year. If any customers are to be transferred from one schedule to another, show revenues separately for the transfer group. Correction factors are used for historic test years only. The total base revenue by class must equal that shown in Schedule E-13a. The billing units must equal those shown in Schedule E-15. PROVIDE TOTAL NUMBER OF BILLS, MWH's, AND BILLING kWh FOR EACH RATE SCHEDULE (INCLUDING STANDARD AND TIME OF USE CUSTOMERS) AND TRANSFER GROUP.

Type of Data Shown:
_X_ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
___ Historical Year Ended 12/31/12
Witness: J. I. Thompson

REVENUE CALCULATION FOR RATE SCHEDULES GSD, GSDT, AND GSTOU

(1) Line No.	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	TRANSFERS FROM RATE SCHEDULE GSDT				TRANSFERS TO RATE SCHEDULE GS			
1	BASE CHARGE	NUMBER OF BILLS		CALCULATED REVENUES	BASE CHARGE	NUMBER OF BILLS		CALCULATED REVENUES
2	STANDARD :	--- BILLS @	--- /BILL	---	STANDARD :	49 BILLS @	$21.00 /BILL	$1,029
3	TOU :	49 BILLS @	$44.00 /BILL	$2,156	TOU:	--- BILLS @	--- /BILL	---
4	DEMAND CHARGE	BILLING KW IN BLOCK			DEMAND CHARGE	BILLING KW IN BLOCK		
5	STANDARD :	--- KW @	--- /KW	---	STANDARD :	--- KW @	--- /KW	---
6	TOU : MAX DEMAND	699 KW @	$2.82 /KW	$1,971	TOU : MAX DEMAND	--- KW @	--- /KW	---
7	TOU : ON-PEAK	650 KW @	$3.18 /KW	$2,067	TOU : ON-PEAK	--- KW @	--- /KW	---
8	ENERGY CHARGE	KWH IN BLOCK			ENERGY/DEMAND CHARGE	KWH IN BLOCK		
9	STANDARD :	--- KWH @	--- /KWH	---	STANDARD :	89,102 KWH @	$0.05300 /KWH	$4,722
10	TOU : ON-PEAK	22,276 KWH @	$0.01525 /KWH	$340	TOU : ON-PEAK	--- KWH @	--- /KWH	---
11	TOU : OFF-PEAK	66,827 KWH @	$0.01525 /KWH	$1,019	TOU : OFF-PEAK	--- KWH @	--- /KWH	---
12			SUBTOTAL BASE REVENUE :	$7,553			SUBTOTAL BASE REVENUE :	$5,751

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13 TRANSFERS FROM RATE SCHEDULE GSDT — TRANSFERS TO RATE SCHEDULE GS

Supporting Schedule: E-13a — Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: By rate schedule, calculate revenues under present and proposed rates for the test year. If any customers are to be transferred from one schedule to another, show revenues separately for the transfer group. Correction factors are used for historic test years only. The total base revenue by class must equal that shown in Schedule E-13a. The billing units must equal those shown in Schedule E-15. PROVIDE TOTAL NUMBER OF BILLS, MWH's, AND BILLING kWh FOR EACH RATE SCHEDULE (INCLUDING STANDARD AND TIME OF USE CUSTOMERS) AND TRANSFER GROUP.

_X_ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
___ Historical Year Ended 12/31/12
Witness: J. I. Thompson

REVENUE CALCULATION FOR RATE SCHEDULES GSD, GSDT, AND GSTOU

(1) Line No.	(2)	(3)		(4)		(5)	(6)	(7)		(8)		(9)
		TRANSFERS FROM RATE SCHEDULE GSDT					TRANSFERS TO RATE SCHEDULE GSD					
1	BASE CHARGE	NUMBER OF BILLS				CALCULATED REVENUES	BASE CHARGE	NUMBER OF BILLS				CALCULATED REVENUES
2	STANDARD :	---	BILLS @	---	/BILL	---	STANDARD :	37	BILLS @	$44.00	/BILL	$1,628
3	TOU :	37	BILLS @	$44.00	/BILL	$1,628	TOU:	---	BILLS @	---	/BILL	---
4	DEMAND CHARGE	BILLING KW IN BLOCK					DEMAND CHARGE	BILLING KW IN BLOCK				
5	STANDARD :	---	KW @	---	/KW	---	STANDARD :	2,525	KW @	$6.84	/KW	$17,271
6	TOU : MAX DEMAND	2,525	KW @	$2.82	/KW	$7,121	TOU : MAX DEMAND	---	KW @	---	/KW	---
7	TOU : ON-PEAK	2,200	KW @	$3.18	/KW	$6,996	TOU : ON-PEAK	---	KW @	---	/KW	---
8	ENERGY CHARGE	KWH IN BLOCK					ENERGY/DEMAND CHARGE	KWH IN BLOCK				
9	STANDARD :	---	KWH @	---	/KWH	---	STANDARD :	1,169,897	KWH @	$0.01749	/KWH	$20,461
10	TOU : ON-PEAK	292,474	KWH @	$0.01525	/KWH	$4,460	TOU : ON-PEAK	---	KWH @	---	/KWH	---
11	TOU : OFF-PEAK	877,423	KWH @	$0.01525	/KWH	$13,381	TOU : OFF-PEAK	---	KWH @	---	/KWH	---
12	VOLTAGE DISCOUNTS						VOLTAGE DISCOUNTS					
13	STANDARD : PRIMARY	---	KW @	---	/KW	---	STANDARD : PRIMARY	---	KW @	---	/KW	---
14		---	KW @	---	/KW	---		---	KW @	---	/KW	---
15		---	KWH @	---	/KWH	---		---	KWH @	---	/KWH	---
18				SUBTOTAL BASE REVENUE :		$33,586				SUBTOTAL BASE REVENUE :		$39,360

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17 TRANSFERS FROM RATE SCHEDULE GSDT — TRANSFERS TO RATE SCHEDULE GSD

Supporting Schedule: E-13a — Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: By rate schedule, calculate revenues under present and proposed rates for the test year. If any customers are to be transferred from one schedule to another, show revenues separately for the transfer group. Correction factors are used for historic test years only. The total base revenue by class must equal that shown in Schedule E-13a. The billing units must equal those shown in Schedule E-15. PROVIDE TOTAL NUMBER OF BILLS, MWH's, AND BILLING kWh FOR EACH RATE SCHEDULE (INCLUDING STANDARD AND TIME OF USE CUSTOMERS) AND TRANSFER GROUP.

Type of Data Shown:
_X_ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
___ Historical Year Ended 12/31/12
Witness: J. I. Thompson

REVENUE CALCULATION FOR RATE SCHEDULES GSD, GSDT, AND GSTOU

(1) Line No.	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1			SUBTOTAL BASE REVENUE (PAGE 3 OF 15):	$93,224,207			SUBTOTAL BASE REVENUE (PAGE 3 OF 15):	$106,008,670
2			SUBTOTAL BASE REVENUE (PAGE 4 OF 15):	$7,233,823			SUBTOTAL BASE REVENUE (PAGE 4 OF 15):	$6,771,081
3			SUBTOTAL BASE REVENUE (PAGE 5 OF 15):	$2,173,520			SUBTOTAL BASE REVENUE (PAGE 5 OF 15):	$2,989,072
4			SUBTOTAL BASE REVENUE (PAGE 6 OF 15):	$7,553			SUBTOTAL BASE REVENUE (PAGE 6 OF 15):	$5,751
5			SUBTOTAL BASE REVENUE (PAGE 7 OF 15):	$33,586			SUBTOTAL BASE REVENUE (PAGE 7 OF 15):	$39,360
6			PRESENT BASE REVENUE:	$102,672,789			PROJECTED BASE REVENUE:	$115,813,934
7							$ INCREASE:	$13,141,145
8							% INCREASE:	12.80%

9 TRANSFERS FROM RATE SCHEDULE____ TRANSFERS TO RATE SCHEDULE____

Supporting Schedule: E-13a Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: By rate schedule, calculate revenues under present and proposed rates for the test year. If any customers are to be transferred from one schedule to another, show revenues separately for the transfer group. Correction factors are used for historic test years only. The total base revenue by class must equal that shown in Schedule E-13a. The billing units must equal those shown in Schedule E-15. PROVIDE TOTAL NUMBER OF BILLS, MWH's, AND BILLING kWh FOR EACH RATE SCHEDULE (INCLUDING STANDARD AND TIME OF USE CUSTOMERS) AND TRANSFER GROUP.

Type of Data Shown:
_X_ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
___ Historical Year Ended 12/31/12
Witness: J. I. Thompson

REVENUE CALCULATION FOR RATE SCHEDULES LP AND LPT

(1) Line No.	(2)	(3)		(4)		(5)	(6)	(7)		(8)		(9)
1	BASE CHARGE	NUMBER OF BILLS				CALCULATED REVENUES	BASE CHARGE	NUMBER OF BILLS				CALCULATED REVENUES
2	STANDARD :	1,560	BILLS @	$225.00	/BILL	$351,000	STANDARD :	1,560	BILLS @	$250.00	/BILL	$390,000
3	TOU :	679	BILLS @	$225.00	/BILL	$152,775	TOU :	679	BILLS @	$250.00	/BILL	$169,750
4	DEMAND CHARGE	BILLING KW IN BLOCK					DEMAND CHARGE	BILLING KW IN BLOCK				
5	STANDARD :	1,021,779	KW @	$10.01	/KW	$10,228,008	STANDARD :	1,021,779	KW @	$12.23	/KW	$12,496,357
6	TOU : MAX DEMAND	1,083,712	KW @	$2.00	/KW	$2,167,424	TOU : MAX DEMAND	1,083,712	KW @	$2.54	/KW	$2,752,628
7	TOU : ON-PEAK	981,714	KW @	$8.04	/KW	$7,892,981	TOU : ON-PEAK	981,714	KW @	$9.64	/KW	$9,660,066
8	ENERGY CHARGE	KWH IN BLOCK					ENERGY CHARGE	KWH IN BLOCK				
9	STANDARD :	434,661,034	KWH @	$0.00750	/KWH	$3,259,958	STANDARD :	434,661,034	KWH @	$0.00934	/KWH	$4,059,734
10	TOU : ON-PEAK	149,160,620	KWH @	$0.00750	/KWH	$1,118,705	TOU : ON-PEAK	149,160,620	KWH @	$0.00934	/KWH	$1,393,160
11	TOU : OFF-PEAK	447,461,857	KWH @	$0.00750	/KWH	$3,356,114	TOU : OFF-PEAK	447,461,857	KWH @	$0.00934	/KWH	$4,179,461
12	REACTIVE CHARGE						REACTIVE CHARGE					
13	STANDARD :	84,982	KVARS @	$1.00	/KVAR	$84,982	STANDARD :	84,982	KVARS @	$1.00	/KVAR	$84,982
14	TOU :	59,056	KVARS @	$1.00	/KVAR	$59,056	TOU :	59,056	KVARS @	$1.00	/KVAR	$59,056
15	VOLTAGE DISCOUNTS						VOLTAGE DISCOUNTS					
16	STANDARD : PRI	209,462	KW @	($0.41)	/KW	($85,879)	STANDARD : PRI	209,462	KW @	($0.55)	/KW	($115,204)
17		209,462	KW @	($0.1001)	/KW	($20,967)		209,462	KW @	($0.1223)	/KW	($25,617)
18		112,842,184	KWH @	($0.0000750)	/KWH	($8,448)		112,842,184	KWH @	($0.0000934)	/KWH	($10,521)
19	TOU : PRIMARY	655,144	MAX KW @	($0.41)	/KW	($268,609)	TOU : PRIMARY	655,144	MAX KW @	($0.55)	/KW	($360,329)
20		655,144	MAX KW @	($0.0200)	/KW	($13,103)		655,144	MAX KW @	($0.0254)	/KW	($16,641)
21		649,601	ON-PK KW @	($0.0804)	/KW	($52,228)		649,601	ON-PK KW @	($0.0984)	/KW	($63,921)
22		104,059,475	ON-PK KWH @	($0.0000750)	/KWH	($7,804)		104,059,475	ON-PK KWH @	($0.0000934)	/KW	($9,719)
23		312,178,423	OFF-PK KWH @	($0.0000750)	/KWH	($23,413)		312,178,423	OFF-PK KWH @	($0.0000934)	/KWH	($29,157)
24				SUBTOTAL BASE REVENUE :		$28,190,552				SUBTOTAL BASE REVENUE :		$34,814,105

25 TRANSFERS FROM RATE SCHEDULE____ TRANSFERS TO RATE SCHEDULE____

Supporting Schedule: E-13a Recap Schedules:

Schedule E-13c | BASE REVENUE BY RATE SCHEDULE - CALCULATIONS | Page 10 of 15

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: By rate schedule, calculate revenues under present and proposed rates for the test year. If any customers are to be transferred from one schedule to another, show revenues separately for the transfer group. Correction factors are used for historic test years only. The total base revenue by class must equal that shown in Schedule E-13a. The billing units must equal those shown in Schedule E-15. PROVIDE TOTAL NUMBER OF BILLS, MWH's, AND BILLING kWh FOR EACH RATE SCHEDULE (INCLUDING STANDARD AND TIME OF USE CUSTOMERS) AND TRANSFER GROUP.

Type of Data Shown:
X Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
___ Historical Year Ended 12/31/12
Witness: J. I. Thompson

REVENUE CALCULATION FOR RATE SCHEDULES LP AND LPT

(1) Line No.	(2)	(3)		(4)		(5)	(6)	(7)		(8)		(9)
		TRANSFERS FROM RATE SCHEDULE LP						TRANSFERS TO RATE SCHEDULE GSD				
1	BASE CHARGE	NUMBER OF BILLS				CALCULATED REVENUES	BASE CHARGE	NUMBER OF BILLS				CALCULATED REVENUES
2	STANDARD :	697	BILLS @	$225.00	/BILL	$156,825	STANDARD :	697	BILLS @	$44.00	/BILL	$30,668
3	TOU :	---	BILLS @	---	/BILL	---	TOU:	---	BILLS @	---	/BILL	---
4	DEMAND CHARGE	BILLING KW IN BLOCK					DEMAND CHARGE	BILLING KW IN BLOCK				
5	STANDARD :	215,828	KW @	$10.01	/KW	$2,160,438	STANDARD :	215,828	KW @	$6.84	/KW	$1,476,264
6	TOU : MAX DEMAND	---	KW @	---	/KW	---	TOU : MAX DEMAND	---	KW @	---	/KW	---
7	TOU : ON-PEAK	---	KW @	---	/KW	---	TOU : ON-PEAK	---	KW @	---	/KW	---
8	ENERGY CHARGE	KWH IN BLOCK					ENERGY CHARGE	KWH IN BLOCK				
9	STANDARD :	94,758,009	KWH @	$0.00750	/KWH	$710,685	STANDARD :	94,758,009	KWH @	$0.01749	/KWH	$1,657,318
10	TOU : ON-PEAK	---	KWH @	---	/KWH	---	TOU : ON-PEAK	---	KWH @	---	/KWH	---
11	TOU : OFF-PEAK	---	KWH @	---	/KWH	---	TOU : OFF-PEAK	---	KWH @	---	/KWH	---
12	REACTIVE CHARGE						REACTIVE CHARGE					
13	STANDARD :	31,283	KVARS @	$1.00	/KVAR	$31,283	STANDARD :	---	KVARS @	---	/KVAR	---
14	TOU :	---	KVARS @	---	/KVAR	---	TOU :	---	KVARS @	---	/KVAR	---
15	VOLTAGE DISCOUNTS						VOLTAGE DISCOUNTS					
16	STANDARD : PRIMARY	0	KW @	($0.41)	/KW	$0	STANDARD : PRIMARY	0	KW @	($0.39)	/KW	$0
17		0	KW @	($0.1001)	/KW	$0		0	KW @	($0.0684)	/KW	$0
18		0	KWH @	($0.0000750)	/KWH	$0		0	KWH @	($0.0001749)	/KWH	$0
19				SUBTOTAL BASE REVENUE :		$3,059,231				SUBTOTAL BASE REVENUE :		$3,164,250

20 TRANSFERS FROM RATE SCHEDULE LP — TRANSFERS TO RATE SCHEDULE GSD

Supporting Schedule: E-13a — Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: By rate schedule, calculate revenues under present and proposed rates for the test year. If any customers are to be transferred from one schedule to another, show revenues separately for the transfer group. Correction factors are used for historic test years only. The total base revenue by class must equal that shown in Schedule E-13a. The billing units must equal those shown in Schedule E-15. PROVIDE TOTAL NUMBER OF BILLS, MWH's, AND BILLING kWh FOR EACH RATE SCHEDULE (INCLUDING STANDARD AND TIME OF USE CUSTOMERS) AND TRANSFER GROUP.

Type of Data Shown:
_X_ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
___ Historical Year Ended 12/31/12
Witness: J. I. Thompson

REVENUE CALCULATION FOR RATE SCHEDULES LP AND LPT

(1) Line No.	(2)	(3)		(4)		(5)	(6)	(7)		(8)		(9)
		TRANSFERS FROM RATE SCHEDULE LPT						TRANSFERS TO RATE SCHEDULE LP				
1	BASE CHARGE	NUMBER OF BILLS				CALCULATED REVENUES	BASE CHARGE	NUMBER OF BILLS				CALCULATED REVENUES
2	STANDARD :	---	BILLS @	---	/BILL	---	STANDARD :	45	BILLS @	$250.00	/BILL	$11,250
3	TOU :	45	BILLS @	$225.00	/BILL	$10,125	TOU:	---	BILLS @	---	/BILL	---
4	DEMAND CHARGE	BILLING KW IN BLOCK					DEMAND CHARGE	BILLING KW IN BLOCK				
5	STANDARD :	---	KW @	---	/KW	---	STANDARD :	51,801	KW @	$12.23	/KW	$633,626
6	TOU : MAX DEMAND	51,801	KW @	$2.00	/KW	$103,602	TOU : MAX DEMAND	---	KW @	---	/KW	---
7	TOU : ON-PEAK	41,800	KW @	$8.04	/KW	$336,072	TOU : ON-PEAK	---	KW @	---	/KW	---
8	ENERGY CHARGE	KWH IN BLOCK					ENERGY CHARGE	KWH IN BLOCK				
9	STANDARD :	---	KWH @	---	/KWH	---	STANDARD :	30,583,697	KWH @	$0.00934	/KWH	$285,652
10	TOU : ON-PEAK	7,645,924	KWH @	$0.00750	/KWH	$57,344	TOU : ON-PEAK	---	KWH @	---	/KWH	---
11	TOU : OFF-PEAK	22,937,773	KWH @	$0.00750	/KWH	$172,033	TOU : OFF-PEAK	---	KWH @	---	/KWH	---
12	REACTIVE CHARGE						REACTIVE CHARGE					
13	STANDARD :	---	KVARS @	---	/KVAR	---	STANDARD :	26,345	KVARS @	$1.00	/KVAR	$26,345
14	TOU :	26,345	KVARS @	$1.00	/KVAR	$26,345	TOU :	---	KVARS @	---	/KVAR	---
15	VOLTAGE DISCOUNTS						VOLTAGE DISCOUNTS					
16	STANDARD : PRI						STANDARD : PRI					
17		---	KW @	---	/KW	---		34,717	KW @	($0.55)	/KW	($19,094)
18		---	KW @	---	/KW	---		34,717	KW @	($0.1223)	/KW	($4,248)
19		---	KWH @	---	/KWH	---		22,331,004	KWH @	($0.0000934)	/KWH	($2,086)
20	TOU : PRI	34,717	MAX KW @	($0.41)	/KW	($14,234)		---	MAX KW @	($0.55)	/KW	---
21		34,717	MAX KW @	($0.0200)	/KW	($694)		---	MAX KW @	($0.0254)	/KW	---
22		30,000	ON-PK KW @	($0.0804)	/KW	($2,412)		---	ON-PK KW @	($0.0984)	/KW	---
23		5,582,751	ON-PK KWH @	($0.0000750)	/KWH	($419)		---	ON-PK KWH @	($0.0000934)	/KWH	---
24		16,748,253	OFF-PK KWH @	($0.0000750)	/KWH	($1,256)		---	OFF-PK KWH @	($0.0000934)	/KWH	---
25				SUBTOTAL BASE REVENUE :		$686,506				SUBTOTAL BASE REVENUE :		$931,347

26	TRANSFERS FROM RATE SCHEDULE LPT	TRANSFERS TO RATE SCHEDULE LP
	Supporting Schedule: E-13a	Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: By rate schedule, calculate revenues under present and proposed rates for the test year. If any customers are to be transferred from one schedule to another, show revenues separately for the transfer group. Correction factors are used for historic test years only. The total base revenue by class must equal that shown in Schedule E-13a. The billing units must equal those shown in Schedule E-15. PROVIDE TOTAL NUMBER OF BILLS, MWH's, AND BILLING kWh FOR EACH RATE SCHEDULE (INCLUDING STANDARD AND TIME OF USE CUSTOMERS) AND TRANSFER GROUP.

Type of Data Shown:
X Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
___ Historical Year Ended 12/31/12
Witness: J. I. Thompson

REVENUE CALCULATION FOR RATE SCHEDULES LP AND LPT

(1) Line No.	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	TRANSFERS FROM RATE SCHEDULE LPT				TRANSFERS TO RATE SCHEDULE GSD			
1	BASE CHARGE	NUMBER OF BILLS		CALCULATED REVENUES	BASE CHARGE	NUMBER OF BILLS		CALCULATED REVENUES
2	STANDARD :	--- BILLS @	--- /BILL	---	STANDARD :	236 BILLS @	$44.00 /BILL	$10,384
3	TOU :	236 BILLS @	$225.00 /BILL	$53,100	TOU:	--- BILLS @	--- /BILL	---
4	DEMAND CHARGE	BILLING KW IN BLOCK			DEMAND CHARGE	BILLING KW IN BLOCK		
5	STANDARD :	--- KW @	--- /KW	---	STANDARD :	86,664 KW @	$6.84 /KW	$592,782
6	TOU : MAX DEMAND	86,664 KW @	$2.00 /KW	$173,328	TOU : MAX DEMAND	--- KW @	--- /KW	---
7	TOU : ON-PEAK	74,000 KW @	$8.04 /KW	$594,960	TOU : ON-PEAK	--- KW @	--- /KW	---
8	ENERGY CHARGE	KWH IN BLOCK			ENERGY CHARGE	KWH IN BLOCK		
9	STANDARD :	--- KWH @	--- /KWH	---	STANDARD :	41,255,184 KWH @	$0.01749 /KWH	$721,553
10	TOU : ON-PEAK	10,313,796 KWH @	$0.00750 /KWH	$77,353	TOU : ON-PEAK	--- KWH @	--- /KWH	---
11	TOU : OFF-PEAK	30,941,388 KWH @	$0.00750 /KWH	$232,060	TOU : OFF-PEAK	--- KWH @	--- /KWH	---
12	REACTIVE CHARGE				REACTIVE CHARGE			
13	STANDARD :	--- KVARS @	--- /KVAR	---	STANDARD :	--- KVARS @	--- /KVAR	---
14	TOU :	3,268 KVARS @	$1.00 /KVAR	$3,268	TOU :	--- KVARS @	--- /KVAR	---
15		SUBTOTAL BASE REVENUE :		$1,134,069		SUBTOTAL BASE REVENUE :		$1,324,719

16 TRANSFERS FROM RATE SCHEDULE LPT — TRANSFERS TO RATE SCHEDULE GSD

Supporting Schedule: E-13a — Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: By rate schedule, calculate revenues under present and proposed rates for the test year. If any customers are to be transferred from one schedule to another, show revenues separately for the transfer group. Correction factors are used for historic test years only. The total base revenue by class must equal that shown in Schedule E-13a. The billing units must equal those shown in Schedule E-15. PROVIDE TOTAL NUMBER OF BILLS, MWH's, AND BILLING kWh FOR EACH RATE SCHEDULE (INCLUDING STANDARD AND TIME OF USE CUSTOMERS) AND TRANSFER GROUP.

Type of Data Shown:
_X_ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
___ Historical Year Ended 12/31/12
Witness: J. I. Thompson

REVENUE CALCULATION FOR RATE SCHEDULES LP AND LPT

(1) Line No.	(2)	(3)		(4)		(5)	(6)	(7)		(8)		(9)
		TRANSFERS FROM RATE SCHEDULE LPT						TRANSFERS TO RATE SCHEDULE GSDT				
1	BASE CHARGE	NUMBER OF BILLS				CALCULATED REVENUES	BASE CHARGE	NUMBER OF BILLS				CALCULATED REVENUES
2	STANDARD :	---	BILLS @	---	/BILL	---	STANDARD :	---	BILLS @	---	/BILL	---
3	TOU :	192	BILLS @	$225.00	/BILL	$43,200	TOU:	192	BILLS @	$44.00	/BILL	$8,448
4	DEMAND CHARGE	BILLING KW IN BLOCK					DEMAND CHARGE	BILLING KW IN BLOCK				
5	STANDARD :	---	KW @	---	/KW	---	STANDARD :	---	KW @	---	/KW	---
6	TOU : MAX DEMAND	79,216	KW @	$2.00	/KW	$158,432	TOU : MAX DEMAND	79,216	KW @	$3.24	/KW	$256,660
7	TOU : ON-PEAK	61,388	KW @	$8.04	/KW	$493,560	TOU : ON-PEAK	61,388	KW @	$3.68	/KW	$224,680
8	ENERGY CHARGE	KWH IN BLOCK					ENERGY CHARGE	KWH IN BLOCK				
9	STANDARD :	---	KWH @	---	/KWH	---	STANDARD :	---	KWH @	---	/KWH	---
10	TOU : ON-PEAK	8,360,135	KWH @	$0.00750	/KWH	$62,701	TOU : ON-PEAK	8,360,135	KWH @	0.01749	/KWH	$146,219
11	TOU : OFF-PEAK	25,080,405	KWH @	$0.00750	/KWH	$188,103	TOU : OFF-PEAK	25,080,405	KWH @	0.01749	/KWH	$438,656
12	REACTIVE CHARGE						REACTIVE CHARGE					
13	STANDARD :	---	KVARS @	---	/KVAR	---	STANDARD :	---	KVARS @	---	/KVAR	---
14	TOU :	1,687	KVARS @	$1.00	/KVAR	$1,687	TOU :	---	KVARS @	---	/KVAR	---
15				SUBTOTAL BASE REVENUE :		$947,683				SUBTOTAL BASE REVENUE :		$1,074,663

16 TRANSFERS FROM RATE SCHEDULE LPT — TRANSFERS TO RATE SCHEDULE GSDT

Supporting Schedule: E-13a — Recap Schedules:

Schedule E-13c | BASE REVENUE BY RATE SCHEDULE - CALCULATIONS | Page 14 of 15

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: By rate schedule, calculate revenues under present and proposed rates for the test year. If any customers are to be transferred from one schedule to another, show revenues separately for the transfer group. Correction factors are used for historic test years only. The total base revenue by class must equal that shown in Schedule E-13a. The billing units must equal those shown in Schedule E-15. PROVIDE TOTAL NUMBER OF BILLS, MWH's, AND BILLING kWh FOR EACH RATE SCHEDULE (INCLUDING STANDARD AND TIME OF USE CUSTOMERS) AND TRANSFER GROUP.

Type of Data Shown:
_X_ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
___ Historical Year Ended 12/31/12
Witness: J. I. Thompson

REVENUE CALCULATION FOR RATE SCHEDULES LP AND LPT

(1) Line No.	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1			SUBTOTAL BASE REVENUE (PAGE 9 OF 15):	$28,190,552			SUBTOTAL BASE REVENUE (PAGE 9 OF 15):	$34,614,105
2			SUBTOTAL BASE REVENUE (PAGE 10 OF 15):	$3,059,231			SUBTOTAL BASE REVENUE (PAGE 10 OF 15):	$3,164,250
3			SUBTOTAL BASE REVENUE (PAGE 11 OF 15):	$686,506			SUBTOTAL BASE REVENUE (PAGE 11 OF 15):	$931,347
4			SUBTOTAL BASE REVENUE (PAGE 12 OF 15):	$1,134,069			SUBTOTAL BASE REVENUE (PAGE 12 OF 15):	$1,324,719
			SUBTOTAL BASE REVENUE (PAGE 13 OF 15):	$947,683			SUBTOTAL BASE REVENUE (PAGE 13 OF 15):	$1,074,663
5			PRESENT BASE REVENUE:	$34,018,041			PROJECTED BASE REVENUE:	$41,109,084
6							$ INCREASE:	$7,091,043
7							% INCREASE:	20.84%

8 TRANSFERS FROM RATE SCHEDULE____ TRANSFERS TO RATE SCHEDULE____

Supporting Schedule: E-13a Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: By rate schedule, calculate revenues under present and proposed rates for the test year. If any customers are to be transferred from one schedule to another, show revenues separately for the transfer group. Correction factors are used for historic test years only. The total base revenue by class must equal that shown in Schedule E-13a. The billing units must equal those shown in Schedule E-15. PROVIDE TOTAL NUMBER OF BILLS, MWH's, AND BILLING kWh FOR EACH RATE SCHEDULE (INCLUDING STANDARD AND TIME OF USE CUSTOMERS) AND TRANSFER GROUP.

Type of Data Shown:
_X_ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
___ Historical Year Ended 12/31/12
Witness: J. I. Thompson

REVENUE CALCULATION FOR RATE SCHEDULES SBS, RTP AND CIS

(1) Line No.	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	PRESENT REVENUE CALCULATION				PROPOSED REVENUE CALCULATION			
2				CALCULATED				CALCULATED
3	SBS BASE CHARGE	NUMBER OF BILLS		REVENUES	SBS BASE CHARGE	NUMBER OF BILLS		REVENUES
4		24 BILLS @	$248.20 /BILL	$5,957		24 BILLS @	$248.20 /BILL	$5,957
5		12 BILLS @	$591.01 /BILL	$7,092		12 BILLS @	$591.01 /BILL	$7,092
6	SBS LOCAL FAC CHG	BILLING KW IN BLOCK			SBS LOCAL FAC CHG	BILLING KW IN BLOCK		
7		115,236 KW @	$2.35 /KW	$270,805		115,236 KW @	$2.35 /KW	$270,805
8		771,832 KW @	$0.81 /KW	$625,184		771,832 KW @	$1.04 /KW	$802,705
9	SBS RESERV CHG	BILLING KW IN BLOCK			SBS RESERV CHG	BILLING KW IN BLOCK		
10		115,236 KW @	$0.95 /KW	$109,474		115,236 KW @	$1.18 /KW	$135,978
11		771,832 KW @	$0.98 /KW	$756,395		771,832 KW @	$1.21 /KW	$933,917
12	SBS DAILY DEMAND	BILLING KW IN BLOCK			SBS DAILY DEMAND	BILLING KW IN BLOCK		
13		42,200 KW @	$0.45 /KW	$18,990		42,200 KW @	$0.56 /KW	$23,632
14	SBS ENERGY CHARGE	KWH IN BLOCK			SBS ENERGY CHARGE	KWH IN BLOCK		
15	ON-PEAK	534,163 KWH @	$0.01055 /KWH	$5,635	ON-PEAK	534,163 KWH @	$0.03460 /KWH	$18,482
16	OFF-PEAK	1,602,488 KWH @	$0.01055 /KWH	$16,906	OFF-PEAK	1,602,488 KWH @	$0.03460 /KWH	$55,446
17	ON-PEAK	3,425,000 KWH @	$0.01022 /KWH	$35,004	ON-PEAK	3,425,000 KWH @	$0.03460 /KWH	$118,505
18	OFF-PEAK	10,275,000 KWH @	$0.01022 /KWH	$105,011	OFF-PEAK	10,275,000 KWH @	$0.03460 /KWH	$355,515
19	SBS VOLTAGE DISCOUNT - TRANSMISSION:				SBS VOLTAGE DISCOUNT - TRANSMISSION:			
20	115,236	LFC KW @	($0.09) /KW =	($10,371)	115,236	LFC KW @	($0.07) /KW =	($8,067)
21	115,236	LFC KW @	($0.0470) /KW =	($5,416)	115,236	LFC KW @	($0.0470) /KW =	($5,416)
22	115,236	RC KW @	($0.0190) /KW =	($2,189)	115,236	RC KW @	($0.0236) /KW =	($2,720)
23	534,163	ON-PEAK @	($0.0002110) /KWH =	($113)	534,163	ON-PEAK @	($0.0006920) /KWH =	($370)
24	1,602,488	OFF-PEAK @	($0.0002110) /KWH =	($338)	1,602,488	OFF-PEAK @	($0.0006920) /KWH =	($1,109)
25			SUBTOTAL BASE REVENUE:	$1,938,026			SUBTOTAL PROJECTED BASE REVENUE:	$2,710,352
26	RTP	768 Bills	1,419,781,859 KWH	$26,562,004	RTP	768 Bills	1,419,781,859 KWH	$32,362,004
27	CIS	12 Bills	42,000,000 KWH	$960,000	CIS	12 Bills	42,000,000 KWH	$960,000
28			PRESENT BASE REVENUE:	$29,460,030			PROJECTED BASE REVENUE:	$36,032,356
29							$ INCREASE:	$6,572,326
30							% INCREASE:	22.31%
31	TRANSFERS FROM RATE SCHEDULE___						TRANSFERS TO RATE SCHEDULE___	

Supporting Schedule: E-13a

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Calculate revenues under present and proposed rates for the test year for each lighting schedule. Show revenues from charges for all types of lighting fixtures, poles and conductors. Poles should be listed separately from fixtures. Show separately revenues from customers who own facilities and those who do not. Annual KWH's must agree with the data provided in Schedule E-15.

Type of Data Shown:
X Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
___ Historical Year Ended 12/31/12
Witness: J. I. Thompson

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)
						Present Rates					Proposed Rates					
Line No.	Type of Facility	Description	Annual Billing Items	Est. Monthly KWH	Annual KWH	Facility Charge	Maintenance Charge	Energy Charge	Total Monthly Charge	$ Total Revenue	Facility Charge	Maintenance Charge	Energy Charge	Total Monthly Charge	$ Total Revenue	Percent Increase
1	HIGH PRESSURE SODIUM VAPOR (OS-I/II)															
2	5400 LUMEN	Open Bottom	2,616	29	75,864	$2.91	$1.57	$0.67	$5.15	$13,472.40	$3.08	$1.66	$0.71	$5.45	$14,257.20	5.83%
3	8800 LUMEN	Open Bottom	582,132	41	23,867,412	$2.49	$1.42	$0.95	$4.86	$2,829,161.52	$2.63	$1.50	$1.00	$5.13	$2,986,337.16	5.56%
4	8800 LUMEN	Open Bottom w/Shield	132	41	5,412	$3.42	$1.67	$0.95	$6.04	$797.28	$3.62	$1.77	$1.00	$6.39	$843.48	5.79%
5	8800 LUMEN	Acorn	24,216	41	992,856	$12.43	$4.19	$0.95	$17.57	$425,475.12	$13.14	$4.43	$1.00	$18.57	$449,691.12	5.69%
6	8800 LUMEN	Colonial	31,536	41	1,292,976	$3.35	$1.65	$0.95	$5.95	$187,639.20	$3.54	$1.74	$1.00	$6.28	$198,046.08	5.55%
7	8800 LUMEN	English Coach	504	41	20,664	$13.57	$4.50	$0.95	$19.02	$9,586.08	$14.34	$4.76	$1.00	$20.10	$10,130.40	5.68%
8	8800 LUMEN	Destin Single	48	41	1,968	$23.34	$7.24	$0.95	$31.53	$1,513.44	$24.67	$7.65	$1.00	$33.32	$1,599.36	5.68%
9	17600 LUMEN	Destin Double	12	82	984	$46.54	$13.96	$1.90	$62.40	$748.80	$49.20	$14.76	$2.01	$65.97	$791.64	5.72%
10	5400 LUMEN	Cobrahead	5,112	29	148,248	$4.09	$1.89	$0.67	$6.65	$33,994.80	$4.32	$2.00	$0.71	$7.03	$35,937.36	5.71%
11	8800 LUMEN	Cobrahead	368,336	41	15,142,776	$3.42	$1.67	$0.95	$6.04	$2,230,789.44	$3.62	$1.77	$1.00	$6.39	$2,360,057.04	5.79%
12	20000 LUMEN	Cobrahead	35,772	80	2,861,760	$4.71	$2.05	$1.85	$8.61	$307,996.92	$4.98	$2.17	$1.96	$9.11	$325,882.92	5.81%
13	26000 LUMEN	Cobrahead	20,064	100	2,006,400	$4.58	$2.02	$2.31	$8.91	$178,770.24	$4.84	$2.14	$2.45	$9.43	$189,203.52	5.84%
14	46000 LUMEN	Cobrahead	20,808	164	3,412,512	$4.62	$2.08	$3.79	$10.69	$222,437.52	$5.10	$2.20	$4.01	$11.31	$235,338.48	5.80%
15	8800 LUMEN	Cut-Off Cobrahead	11,064	41	453,624	$3.76	$1.77	$0.95	$6.50	$71,916.00	$4.00	$1.87	$1.00	$6.87	$76,009.68	5.69%
16	26000 LUMEN	Cut-Off Cobrahead	4,908	100	490,800	$4.64	$2.04	$2.31	$8.99	$44,122.92	$4.90	$2.16	$2.45	$9.51	$46,675.08	5.78%
17	46000 LUMEN	Cut-Off Cobrahead	564	164	92,496	$4.64	$2.08	$3.79	$10.71	$6,040.44	$5.12	$2.20	$4.01	$11.33	$6,390.12	5.79%
18	26000 LUMEN	Bracket Mount CIS	780	100	78,000	$10.62	$3.71	$2.31	$16.64	$12,979.20	$11.23	$3.92	$2.45	$17.60	$13,728.00	5.77%
19	46000 LUMEN	Bracket Mount CIS	540	161	86,940	$11.30	$3.89	$3.73	$16.92	$10,216.80	$11.94	$4.11	$3.94	$19.99	$10,794.60	5.66%
20	26000 LUMEN	Small ORL	468	100	46,800	$10.47	$3.86	$2.31	$16.44	$7,693.92	$11.07	$3.67	$2.45	$17.39	$8,138.52	5.78%
21	46000 LUMEN	Small ORL	1,212	164	198,768	$10.96	$3.79	$3.79	$18.54	$22,470.48	$11.59	$4.01	$4.01	$19.61	$23,767.32	5.77%
22	20000 LUMEN	Large ORL	1,956	80	156,480	$17.72	$5.67	$1.85	$25.24	$49,369.44	$18.73	$5.99	$1.96	$26.68	$52,186.08	5.71%
23	46000 LUMEN	Large ORL	408	164	66,912	$19.96	$6.30	$3.79	$30.05	$12,260.40	$21.10	$6.65	$4.01	$31.77	$12,962.16	5.72%
24	46000 LUMEN	Shoebox	1,248	164	204,672	$9.15	$3.29	$3.79	$16.23	$20,256.04	$9.67	$3.48	$4.01	$17.16	$21,415.68	5.73%
25	16000 LUMEN	Directional	660	68	44,880	$5.14	$2.14	$1.58	$8.86	$5,847.60	$5.43	$2.26	$1.65	$9.35	$6,171.00	5.53%
26	20000 LUMEN	Directional	1,668	80	133,440	$7.43	$2.62	$1.85	$12.10	$20,182.80	$7.85	$2.96	$1.96	$12.79	$21,333.72	5.70%
27	46000 LUMEN	Directional	155,472	164	25,497,408	$5.52	$2.28	$3.79	$11.59	$1,801,920.48	$5.83	$2.41	$4.01	$12.25	$1,904,532.00	5.69%
28	125000 LUMEN	Large Flood	144	379	54,576	$6.76	$3.36	$6.76	$20.90	$3,009.60	$9.28	$3.55	$6.28	$22.09	$3,180.96	5.69%
29	HIGH PRESSURE SODIUM VAPOR (OS-I/II) - PAID UP FRONT															
30	8800 LUMEN	Open Bottom PUF	2,616	41	107,256	N/A	$1.42	$0.95	$2.37	$6,199.92	N/A	$1.50	$1.00	$2.50	$6,540.00	5.49%
31	8800 LUMEN	Acorn PUF	9,864	41	404,424	N/A	$4.19	$0.95	$5.14	$50,700.96	N/A	$4.43	$1.00	$5.43	$53,561.52	5.64%
32	8800 LUMEN	Colonial PUF	6,792	41	276,472	N/A	$1.65	$0.95	$2.60	$17,659.20	N/A	$1.74	$1.00	$2.74	$18,610.08	5.38%
33	8800 LUMEN	English Coach PUF	552	41	22,632	N/A	$4.50	$0.95	$5.45	$3,008.40	N/A	$4.76	$1.00	$5.76	$3,179.52	5.69%
34	8800 LUMEN	Destin Single	204	41	8,364	N/A	$7.24	$0.95	$8.19	$1,670.76	N/A	$7.65	$1.00	$8.65	$1,764.60	5.62%
35	8800 LUMEN	Cobrahead PUF	17,460	41	715,860	N/A	$1.67	$0.95	$2.62	$45,745.20	N/A	$1.77	$1.00	$2.77	$48,364.20	5.73%
36	20000 LUMEN	Cobrahead PUF	3,036	80	242,880	N/A	$2.05	$1.85	$3.90	$11,840.40	N/A	$2.17	$1.96	$4.13	$12,536.88	5.90%
37	26000 LUMEN	Cobrahead PUF	4,908	100	490,800	N/A	$2.02	$2.31	$4.33	$21,251.64	N/A	$2.14	$2.45	$4.59	$22,527.72	6.00%
38	46000 LUMEN	Cobrahead PUF	2,676	164	438,864	N/A	$2.08	$3.79	$5.87	$15,708.12	N/A	$2.20	$4.01	$6.21	$16,617.96	5.79%
39	8800 LUMEN	Cut-Off Cobrahead PUF	1,080	41	44,280	N/A	$1.77	$0.95	$2.72	$2,937.60	N/A	$1.87	$1.00	$2.87	$3,099.60	5.51%
40	26000 LUMEN	Cut-Off Cobrahead PUF	1,776	100	177,600	N/A	$2.04	$2.31	$4.35	$7,725.60	N/A	$2.16	$2.45	$4.61	$8,187.36	5.98%
41	46000 LUMEN	Cut-Off Cobrahead PUF	372	164	61,008	N/A	$2.08	$3.79	$5.87	$2,183.64	N/A	$2.20	$4.01	$6.21	$2,310.12	5.79%
42	26000 LUMEN	Bracket Mount CIS PUF	1,704	100	170,400	N/A	$3.71	$2.31	$6.02	$10,258.08	N/A	$3.92	$2.45	$6.37	$10,854.48	5.81%

Supporting Schedules: E-14

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Calculate revenues under present and proposed rates for the test year for each lighting schedule. Show revenues from charges for all types of lighting fixtures, poles and conductors. Poles should be listed separately from fixtures. Show separately revenues from customers who own facilities and those who do not. Annual KWH's must agree with the data provided in Schedule E-15.

Type of Data Shown:
X Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
___ Historical Year Ended 12/31/12
Witness: J. I. Thompson

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)
						Present Rates					Proposed Rates					
Line No.	Type of Facility	Description	Annual Billing Items	Est. Monthly KWH	Annual KWH	Facility Charge	Maintenance Charge	Energy Charge	Total Monthly Charge	$ Total Revenue	Facility Charge	Maintenance Charge	Energy Charge	Total Monthly Charge	$ Total Revenue	Percent Increase
1	HIGH PRESSURE SODIUM VAPOR (OS-I/II) - PAID UP FRONT (Cont.)															
2	25000 LUMEN	Tenon Top CIS PUF	492	100	49,200	N/A	$3.71	$2.31	$6.02	$2,961.84	N/A	$3.92	$2.45	$6.37	$3,134.04	5.81%
3	25000 LUMEN	Small ORL PUF	192	100	19,200	N/A	$3.68	$2.31	$5.97	$1,146.24	N/A	$3.67	$2.45	$6.32	$1,213.44	5.86%
4	46000 LUMEN	Small ORL PUF	12	164	1,968	N/A	$3.79	$3.79	$7.58	$90.96	N/A	$4.01	$4.01	$8.02	$96.24	5.80%
5	46000 LUMEN	Shoebox PUF	1,044	164	171,216	N/A	$3.29	$3.79	$7.08	$7,391.52	N/A	$3.48	$4.01	$7.49	$7,819.56	5.79%
6	46000 LUMEN	Directional PUF	1,284	164	210,576	N/A	$2.28	$3.79	$6.07	$7,793.88	N/A	$2.41	$4.01	$6.42	$8,243.28	5.77%
7	METAL HALIDE (OS-I/II)															
8	12000 LUMEN	Acorn	468	72	33,696	$12.55	$5.28	$1.66	$19.49	$9,121.32	$13.27	$5.56	$1.76	$20.61	$9,645.48	5.75%
9	12000 LUMEN	Colonial	1,512	72	108,864	$3.47	$2.76	$1.66	$7.89	$11,929.68	$3.67	$2.92	$1.76	$8.35	$12,625.20	5.83%
10	12000 LUMEN	Destin Single	24	72	1,728	$23.46	$8.33	$1.66	$33.45	$802.80	$24.80	$8.61	$1.76	$35.37	$848.88	5.74%
11	32000 LUMEN	Small Flood	33,912	163	5,527,656	$5.84	$2.44	$3.77	$11.85	$401,857.20	$5.98	$2.58	$3.99	$12.58	$424,917.36	5.74%
12	32000 LUMEN	Small Parking Lot	4,272	163	696,336	$10.42	$3.76	$3.77	$17.97	$76,767.84	$11.01	$4.00	$3.99	$19.00	$81,168.00	5.73%
13	100000 LUMEN	Large Flood	26,232	378	9,915,696	$8.09	$4.64	$8.76	$21.69	$568,972.08	$8.55	$5.12	$9.25	$22.92	$601,237.44	5.67%
14	100000 LUMEN	Large Parking Lot	1,596	378	603,288	$17.96	$8.71	$8.76	$33.45	$53,368.20	$19.01	$7.09	$9.25	$35.35	$56,416.60	5.68%
15	METAL HALIDE (OS-I/II) - PAID UP FRONT															
16	12000 LUMEN	Acorn PUF	720	72	51,840	N/A	$5.28	$1.66	$6.94	$4,996.80	N/A	$5.58	$1.76	$7.34	$5,284.80	5.76%
17	12000 LUMEN	Colonial PUF	72	72	5,184	N/A	$2.76	$1.66	$4.42	$318.24	N/A	$2.92	$1.76	$4.68	$336.96	5.86%
18	12000 LUMEN	Destin Single PUF	408	72	29,376	N/A	$8.33	$1.66	$9.99	$4,075.92	N/A	$8.61	$1.76	$10.57	$4,312.56	5.81%
19	24000 LUMEN	Destin Double PUF	60	144	8,640	N/A	$15.56	$3.94	$16.92	$1,135.20	N/A	$16.47	$3.53	$20.00	$1,200.00	5.71%
20	32000 LUMEN	Small Flood PUF	192	163	31,296	N/A	$2.44	$3.77	$8.21	$1,192.32	N/A	$2.58	$3.99	$8.57	$1,261.44	5.80%
21	32000 LUMEN	Small Parking Lot PUF	372	163	60,636	N/A	$3.78	$3.77	$7.55	$2,808.60	N/A	$4.00	$3.99	$7.99	$2,972.28	5.83%
22	100000 LUMEN	Large Flood PUF	456	378	172,368	N/A	$4.64	$8.76	$13.60	$6,201.60	N/A	$5.12	$9.25	$14.37	$6,552.72	5.66%
23	100000 LUMEN	Large Parking Lot PUF	96	378	36,288	N/A	$8.71	$8.76	$15.47	$1,485.12	N/A	$7.09	$9.25	$16.34	$1,568.64	5.62%
24	METAL HALIDE PULSE START (OS-I/II)															
25	13000 LUMEN	Acorn PS	552	65	35,880	$14.24	$5.13	$1.51	$20.88	$11,525.76	$15.05	$5.42	$1.59	$22.06	$12,177.12	5.65%
26	13000 LUMEN	Colonial PS	1,872	65	121,680	$4.44	$2.41	$1.51	$8.36	$15,649.92	$4.69	$2.55	$1.59	$8.83	$16,529.76	5.62%
27	33000 LUMEN	Small Flood PS	13,008	137	1,782,096	$8.32	$3.11	$3.17	$12.60	$163,900.80	$8.68	$3.29	$3.35	$13.32	$173,266.56	5.71%
28	33000 LUMEN	Shoebox PS	492	137	67,404	$7.55	$3.48	$3.17	$14.18	$6,976.56	$7.98	$3.68	$3.35	$14.99	$7,375.08	5.71%
29	METAL HALIDE PULSE START (OS-I/II) - PAID UP FRONT															
30	13000 LUMEN	Acorn PS PUF	372	65	24,180	N/A	$5.13	$1.51	$6.64	$2,470.08	N/A	$5.42	$1.59	$7.01	$2,607.72	5.57%
31	13000 LUMEN	Colonial PS	204	65	13,260	N/A	$2.41	$1.51	$3.92	$799.68	N/A	$2.55	$1.59	$4.14	$844.56	5.61%
32	33000 LUMEN	Small Flood PS PUF	408	137	55,896	N/A	$3.11	$3.17	$6.28	$2,562.24	N/A	$3.29	$3.35	$6.64	$2,709.12	5.73%
33	33000 LUMEN	Shoebox PS	156	137	21,372	N/A	$3.48	$3.17	$6.63	$1,034.28	N/A	$3.68	$3.35	$7.01	$1,093.56	5.73%
34	LED (OS-I/II)															
35	4440 LUMEN	Street Light	300	25	7,500	$12.97	$4.44	$0.58	$17.99	$5,397.00	$13.71	$4.69	$0.61	$19.01	$5,703.00	5.67%
36	9600 LUMEN	E157 SAW	24	54	1,296	$17.56	$5.24	$1.25	$24.05	$577.20	$18.56	$5.54	$1.32	$25.42	$610.08	5.70%

Schedule E-13d | REVENUE BY RATE SCHEDULE - LIGHTING SCHEDULE CALCULATION | Page 3 of 4

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Calculate revenues under present and proposed rates for the test year for each lighting schedule. Show revenues from charges for all types of lighting fixtures, poles and conductors. Poles should be listed separately from fixtures. Show separately revenues from customers who own facilities and those who do not. Annual KWH's must agree with the data provided in Schedule E-15.

Type of Data Shown:
_X_ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
___ Historical Year Ended 12/31/12
Witness: J. I. Thompson

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)
						Present Rates					Proposed Rates					
Line No.	Type of Facility	Description	Annual Billing Items	Est. Monthly KWH	Annual KWH	Facility Charge	Maintenance Charge	Energy Charge	Total Monthly Charge	$ Total Revenue	Facility Charge	Maintenance Charge	Energy Charge	Total Monthly Charge	$ Total Revenue	Percent Increase
1	LED (OS-I/II) - PAID UP FRONT															
2	5000 LUMEN	Acorn A5 PUF	624	25/19	15,600	N/A	$7.44	$0.58	$8.02	$5,004.48	N/A	$7.88	$0.47	$8.33	$5,197.92	3.87%
3	7200 LUMEN	E132 A3 PUF	108	45	4,860	N/A	$7.59	$1.05	$8.64	$933.12	N/A	$8.02	$1.10	$9.12	$984.96	5.56%
4	9600 LUMEN	E157 SAW PUF	96	54	5,184	N/A	$5.24	$1.25	$8.49	$823.04	N/A	$5.54	$1.32	$8.86	$858.58	5.70%
5	MERCURY VAPOR (OS-I/II)															
6	7000 LUMEN	Open Bottom	19,344	67	1,296,048	$2.02	$1.25	$1.55	$4.82	$93,236.08	$2.14	$1.32	$1.64	$5.10	$98,654.40	5.81%
7	3200 LUMEN	Cobrahead	3,180	39	124,020	$3.75	$1.78	$0.90	$6.41	$20,383.80	$3.96	$1.86	$0.95	$6.77	$21,528.60	5.62%
8	7000 LUMEN	Cobrahead	972	67	65,124	$3.41	$1.64	$1.55	$6.80	$6,415.20	$3.80	$1.73	$1.64	$6.97	$6,774.84	5.61%
9	9400 LUMEN	Cobrahead	144	95	13,680	$4.47	$2.00	$2.20	$8.67	$1,248.48	$4.73	$2.11	$2.33	$9.17	$1,320.48	5.77%
10	17000 LUMEN	Cobrahead	1,344	152	204,288	$4.88	$2.08	$3.52	$10.48	$14,085.12	$5.16	$2.20	$3.72	$11.08	$14,891.52	5.73%
11	48000 LUMEN	Cobrahead	12	372	4,464	$9.80	$3.81	$8.81	$22.02	$264.24	$10.36	$3.82	$9.11	$23.29	$279.48	5.77%
12	17000 LUMEN	Directional	168	163	27,384	$7.35	$2.78	$3.77	$13.90	$2,335.20	$7.77	$2.94	$3.99	$14.70	$2,469.60	5.76%
13	CUSTOMER-OWNED MISC STREET/OUTDOOR LIGHTING (OS-I/II)				6,429,527	N/A	N/A	$0.02316	N/A	$148,907.65	N/A	N/A	$0.02448	N/A	$157,394.82	5.70%
14	CUSTOMER OWNED WITH RELAMPING SERVICE AGREEMENT - HIGH PRESSURE SODIUM VAPOR (OS-I/II)															
15	8800 LUMEN	Unmetered	1,116	41	45,756	N/A	$0.64	$0.95	$1.59	$1,774.44	N/A	$0.68	$1.00	$1.68	$1,874.88	5.66%
16	48000 LUMEN	Unmetered	268	164	47,232	N/A	$0.65	$3.79	$4.44	$1,278.72	N/A	$0.69	$4.01	$4.70	$1,353.60	5.86%
17	8800 LUMEN	Metered	228	N/A	N/A	N/A	$0.64	N/A	$0.64	$145.92	N/A	$0.68	N/A	$0.68	$155.04	6.25%
18	20000 LUMEN	Metered	408	N/A	N/A	N/A	$0.65	N/A	$0.65	$265.20	N/A	$0.69	N/A	$0.69	$281.52	6.15%
19	25000 LUMEN	Metered	288	N/A	N/A	N/A	$0.66	N/A	$0.86	$190.08	N/A	$0.70	N/A	$0.70	$201.60	6.06%
20	48000 LUMEN	Metered	588	N/A	N/A	N/A	$0.65	N/A	$0.65	$382.20	N/A	$0.69	N/A	$0.69	$405.72	6.15%
21	CUSTOMER OWNED WITH RELAMPING SERVICE AGREEMENT - METAL HALIDE (OS-I/II)															
22	32000 LUMEN	Unmetered	120	163	19,560	N/A	$0.78	$3.77	$4.55	$546.00	N/A	$0.82	$3.99	$4.81	$577.20	5.71%
23	32000 LUMEN	Metered	516	N/A	N/A	N/A	$0.78	N/A	$0.78	$402.48	N/A	$0.82	N/A	$0.82	$423.12	5.13%
24	HIGH PRESSURE SODIUM VAPOR - CUSTOMER OWNED/CUSTOMER MAINTAINED (OS-I/II)															
25	Customer-Owned	8800	432	41	17,712	N/A	N/A	$0.95	$0.95	$410.40	N/A	N/A	$1.00	$1.00	$432.00	5.26%
26	Customer-Owned	20000	48	80	3,840	N/A	N/A	$1.85	$1.85	$88.80	N/A	N/A	$1.96	$1.96	$94.08	5.95%
27	Customer-Owned	25000	4,224	100	422,400	N/A	N/A	$2.31	$2.31	$9,757.44	N/A	N/A	$2.45	$2.45	$10,348.80	6.06%
28	ADDITIONAL FACILITIES															
29	13 Ft. Decorative Concrete Pole		33,108	N/A	N/A	N/A	N/A	N/A	$15.95	$528,072.60	N/A	N/A	N/A	$17.17	$568,464.36	7.65%
30	17 Ft. Decorative Base Aluminum Pole		300	N/A	N/A	N/A	N/A	N/A	$16.72	$5,016.00	N/A	N/A	N/A	$17.99	$5,397.00	7.60%
31	20 Ft. Fiberglass Pole		29,268	N/A	N/A	N/A	N/A	N/A	$5.92	$173,286.56	N/A	N/A	N/A	$6.37	$186,437.16	7.60%
32	30 Ft. Wood Pole		31,068	N/A	N/A	N/A	N/A	N/A	$3.83	$118,990.44	N/A	N/A	N/A	$4.12	$128,000.16	7.67%
33	30 Ft. Concrete Pole		72,024	N/A	N/A	N/A	N/A	N/A	$8.03	$578,352.72	N/A	N/A	N/A	$8.64	$622,287.36	7.60%
34	30 Ft. Fiberglass Pole w/Pedestal		612	N/A	N/A	N/A	N/A	N/A	$38.01	$23,262.12	N/A	N/A	N/A	$40.91	$25,036.92	7.63%
35	35 Ft. Concrete Pole		3,624	N/A	N/A	N/A	N/A	N/A	$11.70	$42,400.80	N/A	N/A	N/A	$12.59	$45,626.16	7.61%
36	35 Ft. Tenon Top Concrete Pole		2,268	N/A	N/A	N/A	N/A	N/A	$16.15	$36,628.20	N/A	N/A	N/A	$17.38	$39,417.84	7.62%
37	35 Ft. Wood Pole		64,080	N/A	N/A	N/A	N/A	N/A	$5.58	$357,566.40	N/A	N/A	N/A	$6.01	$385,120.80	7.71%

Supporting Schedules: E-14

Recap Schedules:

Schedule E-13d

REVENUE BY RATE SCHEDULE - LIGHTING SCHEDULE CALCULATION

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Calculate revenues under present and proposed rates for the test year for each lighting schedule. Show revenues from charges for all types of lighting fixtures, poles and conductors. Poles should be listed separately from fixtures. Show separately revenues from customers who own facilities and those who do not. Annual KWH's must agree with the data provided in Schedule E-15.

Type of Data Shown:
_X_ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
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Witness: J. I. Thompson

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)
						Present Rates					Proposed Rates					
Line No.	Type of Facility	Description	Annual Billing Items	Est. Monthly KWH	Annual KWH	Facility Charge	Maintenance Charge	Energy Charge	Total Monthly Charge	$ Total Revenue	Facility Charge	Maintenance Charge	Energy Charge	Total Monthly Charge	$ Total Revenue	Percent Increase
1	ADDITIONAL FACILITIES (Cont.)															
2	35 Ft. Aluminum Pole		72	N/A	N/A	N/A	N/A	N/A	$23.03	$1,658.16	N/A	N/A	N/A	$24.78	$1,784.16	7.60%
3	40 Ft. Wood Pole		1,176	N/A	N/A	N/A	N/A	N/A	$6.86	$8,067.36	N/A	N/A	N/A	$7.38	$8,678.88	7.58%
4	45 Ft. Concrete Pole (Tenon Top)		2,016	N/A	N/A	N/A	N/A	N/A	$21.20	$42,739.20	N/A	N/A	N/A	$22.81	$45,984.96	7.59%
5	Single Arm - Shoebox		948	N/A	N/A	N/A	N/A	N/A	$2.22	$2,104.56	N/A	N/A	N/A	$2.39	$2,265.72	7.66%
6	Double Arm - Shoebox		396	N/A	N/A	N/A	N/A	N/A	$2.47	$978.12	N/A	N/A	N/A	$2.66	$1,053.36	7.69%
7	Tenon Top Adapter		768	N/A	N/A	N/A	N/A	N/A	$4.11	$3,156.48	N/A	N/A	N/A	$4.42	$3,394.56	7.54%
8	Optional 100 Amp Relay		72	N/A	N/A	N/A	N/A	N/A	$22.97	$1,653.84	N/A	N/A	N/A	$24.72	$1,779.84	7.62%
9	Miscellaneous Additional Facilities		$617,182.63	N/A	N/A	N/A	N/A	N/A	N/A	$617,182.63	N/A	N/A	N/A	N/A	$617,182.63	0.00%
10	SUBTOTAL OS-I/II PAGE 4 OF 4				-					$677,540.35					$682,124.11	
11	SUBTOTAL OS-I/II PAGE 1 OF 4				80,598,468					$8,727,557.40					$9,223,556.52	
12	SUBTOTAL OS-I/II PAGE 2 OF 4				19,865,616					$1,375,328.88					$1,453,773.48	
13	SUBTOTAL OS-I/II PAGE 3 OF 4				8,746,679					$2,172,236.13					$2,332,090.50	
14	TOTAL OS-I/II KWH AND REVENUE				109,210,763					$12,952,662.78					$13,691,544.61	
15	TOTAL OS-III KWH AND REVENUE				44,157,600	N/A	N/A	$0.04365		$1,927,479.24	N/A	N/A	$0.04614		$2,037,431.66	5.70%
16	TOTAL OS KWH AND REVENUE				153,368,363					$14,880,142.00					$15,728,976.27	
17														TOTAL INCREASE	$848,834.28	
18														% INCREASE	5.70%	

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Supporting Schedules: E-14

Recap Schedules:

Schedule E-14	PROPOSED TARIFF SHEETS AND SUPPORT FOR CHARGES	Page 1 of 74
FLORIDA PUBLIC SERVICE COMMISSION COMPANY: GULF POWER COMPANY DOCKET NO.: 130140-EI	EXPLANATION: Provide proposed tariff sheets highlighting changes in legislative format from existing tariff provisions. For each charge, reference by footnote unit costs as shown on Schedules E-6b and E-7, if applicable. Indicate whether unit costs are calculated at the class or system rate of return. On separate attachment explain any differences between unit costs and proposed charges. Provide the derivation (calculation and assumptions) of all charges and credits other than those for which unit costs are calculated in these MFR schedules, including those charges and credits the company proposes to continue at the present level. Workpapers for street and outdoor lighting rates, T-O-U rates and standard energy charges shall be furnished under separate cover to staff, Commissioners, Commission Clerk, and upon request to other parties to this docket.	Type of Data Shown: _X_ Projected Test Year Ended 12/31/14 ____ Prior Year Ended 12/31/13 ____ Historical Year Ended 12/31/12 Witness: J. I. Thompson

SEE ATTACHED

Supporting Schedules:	Recap Schedules: A-2, E-13c, E-13d

GULF POWER
A SOUTHERN COMPANY

~~Twenty-Sixth~~Twenty-Seventh Revised Sheet No. ii
Canceling ~~Twenty-Fifth~~Twenty-Sixth Revised Sheet No. ii

TABLE OF CONTENTS

Section	Description
Section I	Description of Territory Served
Section II	Miscellaneous
Section III	Technical Terms and Abbreviations
Section IV	Rules and Regulations
Section V	List of Communities Served
Section VI	Rate Schedules

RS - Residential Service
GS - General Service - Non-Demand
GSD - General Service - Demand
LP - Large Power Service
PX - Large High Load Factor Power Service
OS - Outdoor Service
BB - Budget Billing (Optional Rider)
CR - Cost Recovery Clause - Fossil Fuel & Purchased Power
PPCC - Purchased Power Capacity Cost Recovery Clause
ECR - Environmental Cost Recovery Clause
-- - Billing Adjustments and Payment of Bills
ECC - Cost Recovery Clause - Energy Conservation
FLAT-1 - Residential/Commercial FlatBill
GSTOU - General Service Time-of-Use Conservation (Optional)
GSDT - General Service - Demand - Time-of-Use Conservation (Optional)
LPT - Large Power Service - Time-of-Use Conservation (Optional)
PXT - Large High Load Factor Power Service - Time-of-Use Conservation (Optional)
SBS - Standby and Supplementary Service
ISS - Interruptible Standby Service
RSVP - Residential Service Variable Pricing
SP - Surge Protection
RTP - Real Time Pricing
CIS - Commercial/Industrial Service Rider (Optional)
BERS - Building Energy Rating System (BERS)
PV - Rate Rider PV - Photovoltaics (Optional Rider)
MBFC - Military Base Facilities Charge (Optional Rider)
LBIR - Large Business Incentive Rider (Optional Rider)
SBIR - Small Business Incentive Rider (Optional Rider)

ISSUED BY: ~~Susan Story~~S. W. Connally, Jr.

GULF POWER
A SOUTHERN COMPANY

Section No. IV
~~Original~~First Revised Sheet No. 4.8
Canceling Original Sheet No. 4.8

[redacted]

1.10 CONTINUITY OF SERVICE - The Company will exercise reasonable diligence and care to furnish and deliver a regular and uninterrupted supply of electrical energy, but in case the supply should be variable in frequency or voltage, interrupted or fail by reasons of legal process, strike, riot, war, flood, storm, fire, accident, breakdown, or on account of maintenance or repairs to its system, or any part thereof, or of cutting in new equipment or customers or any cause beyond the control of the Company or from the negligence of the Company, its employees, servants or agents, the Company shall not be held liable for any injury, loss, damage, or expense to any Customer, or to any other person, caused directly or indirectly by such variation, interruption, or failure, but shall restore its service to normal as quickly as practicable; and during such interruption the Customer shall have the right to use such other service as may be available. The Customer shall notify the Company promptly of any defect in service or of any trouble or accident to the electric supply.

Continuous service is further dependent upon and subject to conditions brought about by war, the necessities of war, or by the United States Government or any agency of the United States Government, and the Company assumes no obligation to continue the delivery of any quantity of power when or in the event it is required to supply such power to the United States Government, or to any person, firm, corporation, business or industry designated by the United States Government or other Governmental Agency either during time of war or at any other time.

1.11 INCREASE OF SERVICE - Increased service requirements shall be supplied at all times through the existing, or enlarged, service connection and such metering equipment as will properly measure the amount of energy and its maximum demand, provided that the necessary enlargement of the facilities in service does not require changes in point of delivery. The Customer

GULF POWER
A SOUTHERN COMPANY

Section No. VI
~~First~~Second Revised Sheet No. 4.9
Canceling ~~Original~~First Revised Sheet No. 4.9

[redacted]

1.11 INCREASE OF SERVICE - (Continued)

shall give reasonable advance notice to the Company of any changes which affect the connected load under contract to the end that the Company will have ample time to provide adequate service facilities.

1.12 RIGHT-OF-WAY - The Customer, upon making application for service, thereby grants the Company, free of cost, right-of-way over and under property owned, leased, or controlled by the Customer, for the installation of poles, ducts, cables, wires, transformers, vaults, fixtures, and appurtenances necessary for service to the Customer; and the Customer shall provide, without cost to the Company, suitable location and housing for all apparatus installed and owned by the Company on Customer's premises; and all necessary permission for ingress and egress to and from the Customer's premises shall be provided by the Customer to enable the properly identified employees of the Company to read meters, install, repair, maintain, and remove the Company's property and inspect and test electrical equipment within or upon the premises at all reasonable times and to perform all other necessary duties in connection with the service to the Customer and the Company's property.

1.13 CUSTOMER WIRING - The wiring and electrical equipment in or upon the premises of the Customer to the ~~point of service entrance~~Delivery Point shall be in conformity with the rules and regulations of constituted authorities pertaining thereto, and the rules set forth in the Company's "Electric Service and Meter Installations" as issued from time to time, but the Company does not assume responsibility therefore and shall not be liable for any defects or damages due to defective customer wiring.

ISSUED BY: ~~E. L. Addison, President~~S. W. Connally, Jr. **~~EFFECTIVE: December 28, 1979~~**

GULF POWER
A SOUTHERN COMPANY

Section No. VI
~~Third~~Fourth Revised Sheet No. 4.10
Canceling ~~Second~~Third Revised Sheet No. 4.10

[redacted]

1.14 ~~RESIDENTIAL~~ ENERGY AUDITS

~~1.14.1 ENERGY CHECK-UP - When requested by a residential customer, the Company will make an inspection of that Customer's residence to assist the Customer in identifying appropriate electric energy conservation measures. The Company will give the Customer a report of the energy saving improvements that can be made and the expected savings in future electric bills. This inspection and report is called an Energy Check-up. This service will be available to all residential Customers at no charge to the Customer.~~

~~1.14.2 RESIDENTIAL CONSERVATION SERVICE (RCS) AUDIT - Residential Conservation Service (RCS) Audits as described and governed by Florida Public Service Commission rules located in Chapter 25-6 Part IX, Florida Administrative Code will be provided by the Company to its eligible customers at a charge of $15.00 per audit. The Company will ensure that the afore-mentioned rules and any subsequent amendments thereto are the guidelines for this audit.~~ – The Company will offer energy audits to customers in accordance with Commission Rule 25-17.003, Florida Administrative Code.

1.15 PAYMENT FOR SERVICE - Employees of the Company are forbidden to demand or accept any personal compensation from Customers of the Company, and payment for any services rendered should only be made upon presentation of formal statement by the Company.

1.16 RESPONSIBILITY FOR PROPERTY OF THE COMPANY - All property of the Company that is placed in or upon the Customer's premises, and used in supplying service to him, is placed there under his protection; Customer shall be liable for any loss of or damage to such property, normal wear and tear excepted, and shall pay the Company the amount of any such loss or damage.

1.17 DAMAGES TO PROPERTY - Neither the Customer nor the Company shall be responsible for damage to the machinery, apparatus, appliances or other property of the other caused by lightning or by defects in or failure of the machinery, apparatus, or appliances of the one suffering such damages from such causes; and the Company shall not be in any way responsible for the transmission or control of electrical energy beyond the ~~point of connection to the Customer's premises~~Delivery Point, and shall not be liable for damages on account of injuries to person or property resulting in any manner from the receiving, use, or

GULF POWER
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Section No. VI
~~Second~~Third Revised Sheet No. 4.11
Canceling ~~First~~Second Revised Sheet No. 4.11

[redacted]

1.17 DAMAGES TO PROPERTY - (continued)
application by the Customer of such electrical energy. The Customer must keep his, her, or its machinery, lines, apparatus and appliances in a safe condition and shall indemnify and save harmless the Company from the payment of any sums or sum of money to any person whomsoever, including attorney's fees and court costs, which it may be called upon to pay on account of damage to property or fatal or personal injuries to individuals resulting from or which may be in anyway caused by the operation and maintenance of the machinery, lines, apparatus and appliances belonging to the Customer.

Reverse phase relays, phase failure relays and low voltage or voltage unbalance releases, preferably of the adjustable time-delay type, with circuit breakers or equivalent devices shall be provided by the Customer to disconnect automatically all motor installations which cannot be safely reversed or which would be damaged by a phase or voltage failure.

1.18 STANDARD NOMINAL VOLTAGE - The Company will adopt a standard nominal voltage, or standard nominal voltages, as may be required by its distribution system, or for each of the several districts into which the system may be divided, and the voltages maintained at the Company's main service terminals as installed for each Customer or group of customers shall be maintained reasonably constant. Information as to the standard nominal voltage supplied to any district or area will be furnished by the Company upon request.

If an industrial Customer uses lighting incidental to his power service and the voltage regulation is unsatisfactory for lighting purposes, then the Customer shall install any required regulative apparatus at his own expense.

1.19 NOTICES - Any notice required or authorized to be given under these "Rules and Regulations" or under the provisions of any contracts between the Company and Customer, shall be in writing addressed to the Customer at the premises at which the service is rendered, or at such other address as may have been furnished by the Customer for receiving his bills from the Company, or at Customer's last known address, and mailed in the ordinary course of the Company's business; or by the Customer to the Company, by mail, addressed to the Company; or by either party by serving same personally upon the other. The date of serving or mailing any such notice shall be the date upon which the number of days specified for notice shall begin to run. Notice may be provided to customers via electronic mail if the customer consents to receiving notice in such format.

Notice to the Company by the Customer should not be given to employees of the Company when away from the office, or in the office after or before business hours, as such will not be accepted as binding and formal notification to the Company.

1.20 PROMISES - No promise, agreement, or representation of any employee or officer of the Company shall bind the Company unless the same be in writing and approved by the signature of an officer of the Company, and no employee or officer of the Company is authorized to waive this condition.

GULF POWER
A SOUTHERN COMPANY

Section No. IV
~~Fourteenth~~Fifteenth Revised Sheet No. 4.13
Canceling ~~Thirteenth~~Fourteenth Revised Sheet No. 4.13

PAGE	EFFECTIVE DATE
of	~~May 29, 2007~~

2.5 NON-ASSIGNMENT OF DEPOSIT - The receipt for deposit cannot be assigned by the Customer without the written consent of the Company.

2.6 PAYMENT OF PREVIOUS ACCOUNTS REQUIRED - Applications for service will not be accepted by the Company until the Applicant has paid to the Company all sums at any time owing and then unpaid:
(1) By Applicant for service of the same class rendered by the Company whether at the premises applied for or at any other premises, or
(2) By the previous occupant of the premises as long as the current Applicant or Customer occupied the premises at the time the delinquency occurred and the previous Customer continues to occupy the premises and such previous Customer shall benefit from such service.

PART III
LINE EXTENSION AND SERVICE CONNECTION REGULATIONS

3.1 APPLIES TO ALL APPLICANTS - These regulations apply to all applicants requesting service from the regular distribution systems of the Company for residential, commercial and industrial usage. Customers requesting service from the transmission system of the Company may require individual consideration and will be handled accordingly as they request service.

3.2 CONNECTION OF INITIAL SERVICE - Where the Company's distribution circuits already are in place on the pole adjacent to the Customer's premises requiring only the installation of service wires and meter, the Company will place the service wires and meter completing the connection to provide service. The Customer shall pay a charge of $27.00 residential / $50.00 non-residential for such connection, in addition to the deposit provided for elsewhere. The Company shall have the discretion to waive the connection fee that would otherwise apply to the new or existing Customer as a consequence of significant damage to their premises caused by a natural disaster or other similar conditions for which an emergency has been declared by a governmental body authorized to make such a declaration.

3.3 CONNECTION OF EXISTING SERVICE - Where service has previously been connected at a premise, a $27.00 residential / $50.00 non-residential service charge shall be paid for all subsequent reconnections, except for restoration of service after violation of regulations as provided in Paragraph 4.11 of these Rules or at the Company's discretion as a consequence of significant damage to the new or existing Customer's premises caused by a natural disaster or other similar conditions for which an emergency has been declared by a governmental body authorized to make such a declaration.

3.4 SERVICE IF NEW OR UPGRADED FACILITIES ARE REQUIRED - When new or upgraded facilities are required to place the service applied for adjacent to the Customer's premises, a test will be run on the projected revenue vs. the estimated construction costs, exclusive of meters and services.

Contributions-in-aid-of-construction for new or upgraded overhead facilities:
$CIAC_{OH}$ = Construction Cost - (4 years expected Incremental base energy revenue) - (4 years expected incremental base demand revenue)

Contributions-in-aid-of-construction for new or upgraded underground facilities:
$CIAC_{UG}$ = $CIAC_{OH}$ + Estimated difference between cost of providing the service underground and overhead

ISSUED BY: ~~Susan Story~~S. W. Connally, Jr.

GULF POWER
A SOUTHERN COMPANY

Section No. IV
~~Twelfth~~Thirteenth Revised Sheet No. 4.14
Canceling ~~Eleventh~~Twelfth Revised Sheet No. 4.14

3.4 (continued)
If the revenue supports construction, then no CIAC is applicable. If the revenue/ construction comparison shows a CIAC to be owing, the applicant will pay to the Company in advance of making the extension the amount from the formula, adjusted by the approved tax effect multiplier. Such payment may be waived or a special agreement may be made providing for the repayment of such money to the applicant, when additional business is secured, upon terms to be fixed by the Company. Where more customers than the initial applicant are expected to be served by the new or upgraded facilities within a period not to exceed three years, the Company shall prorate the total CIAC over the number of end-use customers expected. Where the full amount of CIAC is required from the initial applicant, the Company will return to the initial applicant any subsequent CIAC payments received from such expected customers. Title to all lines will remain with the Company. When service is connected to the Customer's premises, a service charge shall be paid in accordance with the provisions of Paragraph 3.2 above. The Company shall apply the above formulas uniformly to residential, commercial, and industrial customers requiring new or upgraded facilities at any voltage level.

3.5 LIMITATIONS ON THREE PHASE SERVICE - In general, the Company will furnish single phase service for any residential or commercial loads involving no single motor larger than five horsepower. It has never contemplated supplying service to any motor rated at three horsepower or smaller at three phase anywhere. Therefore, unless already available, three phase service will not be furnished for residential loads or for commercial loads where no commercial motor exceeds three horsepower until the Customer makes a contribution to the Company equal to the excess of the cost of providing three phase service over the cost of furnishing service to such load at single phase.

3.6 UNDERGROUND SERVICE IN AN OVERHEAD AREA - Conversion of existing overhead facilities to underground shall be handled in accordance with the provisions of Part VI UNDERGROUND DISTRIBUTION FACILITIES.

3.7 CONNECTION OF TEMPORARY SERVICE - Where the Company's distribution circuits are already in place on the pole adjacent to the Customer's premises requiring only the installation of a service drop and meter, the Company will place the service drop and meter completing the connection to provide temporary service. The service drop and meter installation shall not exceed 200 amperes and must utilize self-contained, non-demand metering. The customer shall pay a charge of $110.00 for each such connection in addition to the deposit provided for elsewhere.

3.7.1 TEMPORARY SERVICE INVOLVING EXTENSIONS - In case the establishing of temporary service involves cost of labor and materials, other than as described in 3.7 above, the applicant must pay in advance the total estimated cost of installing and dismantling the necessary facilities, less the salvage value of the material returnable to stores for re-use, less projected revenues associated with the temporary service. This payment shall be in addition to the appropriate service charge for a Service Connection to existing distribution system and the deposit for guarantee of the energy billing provided for elsewhere.

ISSUED BY: ~~Susan Story~~S. W. Connally, Jr.

GULF POWER
A SOUTHERN COMPANY

Section No. IV
~~Seventh~~Eighth Revised Sheet No. 4.20
Canceling ~~Sixth~~Seventh Revised Sheet No. 4.20

PAGE	EFFECTIVE DATE
of	~~June 7, 2002~~

PART V
CONTRACT AND ENFORCEMENT REGULATIONS

5.1 CUTOFF REGULATIONS - Bills for service are payable monthly, unless otherwise stated in rate schedules, and are considered delinquent after the expiration of twenty (20) days from the date of mailing or delivery by the utility. If not paid at the Company's office or other designated place by the delinquent date, the Company at any time thereafter may suspend service after giving five (5) day's written notice to the customer of such delinquency and of the Company's intention to discontinue service. Such written notice will be separate and apart from any bill for service. If the amount due remains unpaid after suspension of service, the Company may treat the contract as canceled and at an end.

5.2 EXTENSION OF TIME FOR PAYMENT OF BILL - The Company may, however, extend the time for paying any one or more bills, or any part thereof, and its action in so doing shall be without prejudice to its rights thereafter to suspend service as provided in these rules; and by so doing, the Company shall not be held or considered as waiving its rights or its option thereafter to suspend service and/or treat the contract as canceled and at an end.

5.3 RESTORATION CHARGE - When the service of a Customer has been discontinued after violation of rules, all amounts due for service up to the date of discontinuance thereof shall become due and must be paid before service will be reconnected and the Company shall require the Customer to pay a restoration charge before reconnecting. The restoration charge shall be determined as follows:
(1) ~~$35.00~~60.00 if the service is restored at the meter during normal business hours.
(2) ~~$55.00~~80.00 if the service is restored at the meter after hours.
(3) ~~$95.00~~100.00 if the service is restored because of an inaccessible meter.

5.4 PREMISE VISIT CHARGE - Whenever payment for service is delinquent and a field service representative is required to call at the Customer's premise, and service is not suspended, a ~~$20.00~~30.00 fee shall be charged.

5.5 FAULTY WIRING ON CUSTOMER'S PREMISES - The Company reserves the right to disconnect from its lines, or to refuse to connect to its lines, any Customer or applicant whose wiring is not in accordance with standard good practice; however, the Company does not assume any responsibility for installation or maintenance inspection of Customer's wiring or installation.

5.6 MEDICALLY ESSENTIAL SERVICE - For purposes of this section, a Medically Essential Service Customer is a residential customer whose electric service is medically essential, as affirmed through the certificate of a doctor of medicine licensed to practice in the State of Florida. Service is "medically essential" if the customer has continuously operating electric-powered medical equipment necessary to sustain the life of or avoid serious medical complications requiring immediate hospitalization of the customer or another permanent resident at the service address. The Physician's certificate shall explain briefly and clearly, in non-medical terms, why continuance of electric service is medically essential, and shall be consistent with the requirements of the Company's tariff. A customer who is certified as a Medically Essential Service Customer must renew such certification periodically through the procedures outlined above. The Company may require certification no more frequently than 12 months.

The Company shall provide Medically Essential Service Customers with a limited extension of time, not to exceed thirty (30) days, beyond the date service would normally be subject to disconnection for non-payment of bills (following the requisite notice pursuant to Rule 25-6.105(5) of the Florida Administrative Code). The Company shall provide the Medically Essential Service Customer with written notice specifying the date of disconnection based on the limited extension. The Medically Essential Service

GULF POWER
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Section No. IV
~~Second~~Third Revised Sheet No. 4.23
Canceling ~~First~~Second Revised Sheet No. 4.23

6.2.2 (continued)

Any Applicant seeking the installation of underground distribution facilities pursuant to a written request hereunder shall execute the Agreement For Underground Construction Standards set forth in Section VII of this tariff, Standard Contract Forms, at Sheet no. 7.25. Failure to execute said agreement within 180 days after the delivery by Gulf Power Company of a binding cost estimate shall result in forfeiture of the deposit made. Any subsequent request for underground facilities will require the payment of a new deposit and the presentation of a new binding cost estimate. For good cause Gulf may extend the 180 day time limit. Upon execution of the Agreement For Underground Construction Standards, payment in full of the differential cost specified in the binding cost estimate, and compliance with the requirements of this tariff, Gulf shall proceed to install the facilities identified in a timely manner.

As a condition precedent to the conversion of any overhead distribution facilities, the Company may require that the Applicant ~~shall have~~obtain executed agreements with all affected pole licensees (e.g. telephone, cable TV, etc.) for the simultaneous conversion of those pole licensees' facilities and provide Gulf with a copy of the Agreement(s). Such agreements shall specifically acknowledge that the affected pole licensee will coordinate the conversion with Gulf and other licensees in a timely manner so as to not create unnecessary delays. Failure to present to Gulf Power Company executed copies of any necessary agreements with affected pole licensees within 180 days after delivery of the binding cost agreement to the Applicant shall result in forfeiture of the deposit paid for the binding cost estimate, the return of any differential cost paid for the binding cost estimate, the return of any differential cost paid less any actual cost incurred, and the termination of any Agreement For Underground Construction Standards entered into between the Applicant and Gulf Power Company.

6.2.3 CHANGES TO PLANS. The Applicant shall pay for all additional costs incurred by the Company due to changes made by the Applicant in the subdivision layout or grade after original agreed upon design has been completed by the Company.

6.2.4 UNDERGROUND INSTALLATIONS NOT COVERED. Where the Applicant requests underground electric facilities not specifically covered by these Rules and Regulations, or in areas where the terrain, loads, and/or equipment are not typical, and where overhead facilities would otherwise normally be provided, the Applicant and the Company may enter into an agreement outlining the terms and conditions of the installation prior to such installation.

6.2.5 TYPE OF SYSTEM PROVIDED. Underground residential distribution facilities are of standard Company design, generally with all cable in duct or conduit and above-grade appurtenances. Unless otherwise stated, service provided will be 120/240 volt single phase. If other types of facilities are requested by the Applicant or required by governmental authority, the Applicant or governmental authority will pay the additional costs if any.

GULF POWER
A SOUTHERN COMPANY

Section No. IV
~~Fifth~~Sixth Revised Sheet No. 4.24
Canceling ~~Fourth~~Fifth Revised Sheet No. 4.24

6.2.6 OWNERSHIP OF UNDERGROUND FACILITIES. The Company will install, own, and maintain the electric distribution facilities up to the designated point of delivery for residential and commercial services up to and including 400A except as otherwise stated. Any payment made by the Applicant under the provisions of these Rules will not convey to the Applicant any rights of ownership. The Applicant may, subject to a contractual agreement with the Company, construct and install a portion of the underground distribution facilities provided:

(a) such work meets the Company's construction standards;

(b) the Company will own and maintain the completed distribution facilities;

(c) such agreement is not expected to cause the general body of ratepayers to incur greater costs;

(d) the Applicant agrees to pay Gulf Power Company's current applicable ~~hourly rate for engineering personnel for all time spent reviewing and inspecting the Applicants work done; and~~Engineering and Supervision rate associated with the estimate of work to be performed by the Applicant. This amount represents the cost of Gulf's engineering time to review and inspect the Applicant's work.

(e) the Applicant agrees to rectify any deficiencies found by Gulf Power Company prior to the connection of any customers to the underground electric distribution system or the connection of the underground electric distribution facilities to Gulf Power Company's distribution system. Furthermore, the deficiencies must be corrected in a timely manner or Gulf shall construct the system improvement using overhead facilities and the Applicant will have to pay the cost of such improvement and the cost of its removal before the corrected underground facilities will be connected.

6.2.7 RIGHTS OF WAY AND EASEMENTS.

(a) General Requirements. The Company shall construct, own, operate, and maintain distribution facilities only along easements, public streets, roads, and highways which the Company has the legal right to occupy, and on public lands and private property across which rights of way and easements satisfactory to the Company may be obtained without condemnation or cost to the Company.

(b) Scheduling, Clearing, and Grading. Rights of way and easements suitable to the Company must be furnished by the Applicant in reasonable time to meet service requirements, and must be cleared of trees, tree stumps, paving and other obstructions, staked to show property lines and final grade, and must be graded to within six (6) inches of final grade by the Applicant before the Company will commence construction, all at no charge to the Company. Such clearing and grading must be maintained by the Applicant during construction by the Company. Grade stakes must be provided at transformer locations.

Should paving, grass, landscaping, or sprinkler systems be installed prior to the construction of the underground distribution facilities, the Applicant shall pay the added costs of trenching, backfilling, and restoring the paving, grass, landscaping, and sprinkler systems to their original condition.

ISSUED BY: ~~Mark Crosswhite~~S. W. Connally, Jr.

GULF POWER
A SOUTHERN COMPANY

Section No. IV
~~Original~~First Revised Sheet No. 4.26.3
Canceling Original Sheet No. 4.26.3

6.3.2 (continued)

~~(c) The Applicant is required to pay all additional costs required for a service lateral length in excess of the minimum which would have been needed to reach the Company's designated point of delivery.~~

(~~d~~c) The above charges are based upon arrangement of distribution facilities that will permit serving the local single-phase underground distribution system within the subdivision from existing overhead feeder mains. If the feeder mains or other three-phase facilities within the subdivision are deemed necessary by the Company to provide and/or maintain adequate service and are required by the Applicant or governmental agency to be installed underground, the Applicant shall pay the Company the estimated cost differential between the underground feeder mains, or other three-phase facilities and the equivalent overhead facilities.

6.3.3 FACILITIES TO BE UNDERGROUND. All service laterals and secondary and single phase primary conductors shall be underground. Appurtenances such as transformers, pedestal-mounted terminals, switching equipment, and meter cabinets may be placed above ground. Feeder mains required within a subdivision may be overhead if the Applicant and the Company determine that the additional cost of underground is not justified for that particular location, unless otherwise required by governmental authority, in which case the differential cost will be borne by the Applicant or governmental authority.

6.3.4 POINT OF DELIVERY. The point of delivery to the building shall be determined by the Company and normally will be at the point of the building nearest the point at which the underground secondary system is available to the property to be served. If the point of delivery on any building is more than fifty (50) feet in length from the available secondary system (seventy [70] feet for low density subdivisions), then the Applicant may be required to make additional payment for the excess length.

ISSUED BY: ~~Susan Story~~S.W. Connally, Jr.

GULF POWER
A SOUTHERN COMPANY

Section No. IV
~~Seventh~~Eighth Revised Sheet No. 4.27
Canceling ~~Sixth~~Seventh Revised Sheet No. 4.27

6.3.5 LOCATION OF METER AND SOCKET & SERVICE ENTRANCE FACILITIES. The Applicant shall install a meter socket and suitable service entrance facilities at the point designated by the Company in accordance with the Company's specifications. Service conductors shall be installed, where possible, in a direct line to the point of delivery.

6.3.6 DEVELOPMENT OF SUBDIVISIONS. The above charges are based on reasonably full and timely use of the land being developed. Where the Company is required to construct underground electric facilities through a section or sections of the subdivision or development where, in the opinion of the Company, service will not be required for at least two years, the Company may require a deposit from the Applicant before construction is commenced. This deposit, to guarantee performance, will be based on the estimated total cost of such facilities rather than the differential cost. The amount of the deposit, without interest, in excess of any charges for underground service will be returned to the applicant on a pro-rata basis at quarterly intervals on the basis of installations to new customers. Any portion of such deposit remaining unrefunded, after five years from the date the Company is first ready to render service from the extension, will be retained by the Company.

6.4 UNDERGROUND DISTRIBUTION TO MULTIPLE-OCCUPANCY RESIDENTIAL BUILDINGS

6.4.1 AVAILABILITY. After receipt of proper application and compliance by the Applicant with applicable Company rules and procedures, the Company will install underground distribution facilities within that tract of land upon which multiple-occupancy residential buildings containing five (5) or more separate dwelling units will be constructed.

6.4.2 CONTRIBUTION BY APPLICANT. Service for new multiple-occupancy residential buildings will be constructed underground within the property to be served to the point of delivery at or near the building by the Company at no charge to the Applicant, provided the Company is free to construct its service extension or extensions in the most economical manner and reasonably full use is made of the tract of land upon which the multiple-occupancy buildings will be constructed. The Applicant must pay a cost differential for any non-residential service such as a pool or office building if such service is not ganged with other single phase residential services.

6.4.3 METER SOCKETS AND SERVICE ENTRANCE FACILITIES. The Applicant shall install service entrance facilities including meter sockets or suitable facilities for installation of the Company's meters at a location suitable to the Company. Meter sockets of facilities for installation of the Company's meters shall be a type and manufacture approved by the Company.

ISSUED BY: ~~Susan Story~~S. W. Connally, Jr.

GULF POWER
A SOUTHERN COMPANY

Section No. IV
~~Ninth~~Tenth Revised Sheet No. 4.28.1
Canceling ~~Eighth~~Ninth Revised Sheet No. 4.28.1

6.5.3 (continued)

An Applicant desiring the Company to proceed with construction of the underground facilities described in a binding cost estimate may enter into a contract with the Company based on said estimate on or before the 180th day following Applicant's receipt of the estimate. So long as the contract is entered into by such date, the contract shall provide that the charges the Applicant is obligated to pay for installation of the underground facilities ~~will be the actual costs incurred subject to the limitation that the charges to the Applicant~~ will not exceed 110 percent of the amount set forth in the binding estimate. So long as said contract is entered into by the date specified above, it shall further provide that the total charges the Applicant is obligated to pay for installation of underground facilities determined as set forth in section 6.5.4 below shall be reduced by the amount of the posted deposit associated with the binding cost estimate.

6.5.4 CONTRIBUTION BY APPLICANT. Prior to the installation of underground facilities covered by this subpart, the Applicant and the Company must enter into a contractual agreement setting forth the terms and conditions of the installation. The charge to be paid by the Applicant for underground facilities pursuant to the contractual agreement shall be determined as follows:

The cost of construction of the underground distribution facilities including the construction cost of the underground service lateral(s) to the meter(s) of the customer(s) and the net present value of the operating cost over the expected life of the underground facilities;

plus (if applicable) the estimated remaining book value of any existing facilities to be removed as part of the conversion of existing overhead facilities to underground, less the estimated net salvage value of the facilities to be removed;

minus the estimated construction cost to build new overhead facilities including the service drop(s) to the meter(s) of the customer(s) and the net present value of the operating cost over the expected life of the overhead facilities.

If the installation of the underground facilities is made pursuant to a contractual agreement based on a binding cost estimate received by the Applicant no more than 180 days prior to the date of the contractual agreement, the provisions of section 6.5.3 shall limit and modify the contribution to be paid by the Applicant for underground facilities.

6.5.5 METER SOCKETS AND SERVICE ENTRANCE FACILITIES. The Applicant shall install service entrance facilities including meter sockets or suitable facilities for installation of the Company's meters at a location suitable to the Company. Meter sockets or facilities for installation of the Company's meters shall be of a type and manufacture approved by the Company.

6.5.6 UNDERGROUND SECONDARY LATERAL SERVICE IN AN OVERHEAD RESIDENTIAL OR COMMERCIAL AREA. When requested by a residential or commercial Applicant, the Company will install, own, and maintain an underground secondary service lateral from its overhead facilities to the Applicant's point of delivery. The Applicant shall install a meter socket and suitable service entrance facilities at the point designated by the Company in accordance with the Company's specification. Prior to such installation, the Applicant and the Company will enter into an agreement outlining the terms and conditions of the installation, and the Applicant will be required to pay the Company in advance the cost differential between an overhead service and an underground service. The Applicant may participate in the process by trenching and installing the duct and/or providing the duct.

ISSUED BY: ~~Susan Story~~S. W. Connally, Jr.

GULF POWER
A SOUTHERN COMPANY

Section No. VI
~~Twenty-Eighth~~Twenty-Ninth Revised Sheet No. 6.2
Canceling ~~Twenty-Seventh~~Twenty-Eighth Revised Sheet No. 6.2

Designation	URSC	Classification	Sheet No.
RSVP	RS1	Residential Service Variable Pricing (Optional)	6.75
SP		Surge Protection	6.79
RTP		Real Time Pricing	6.80
CIS		Commercial/Industrial Service (Optional Rider)	6.84
BERS		Building Energy Rating System (BERS)	6.87
PV		Rate Rider PV - Photovoltaics (Optional Rider)	6.89
MBFC		Military Base Facilities Charge (Optional Rider)	6.91
LBIR		Large Business Incentive Rider (Optional Rider)	6.92
SBIR		Small Business Incentive Rider (Optional Rider)	6.94

ISSUED BY: ~~Susan Story~~S. W. Connally, Jr.

GULF POWER
A SOUTHERN COMPANY

Section No. VI
~~Twenty-Ninth~~Thirtieth Revised Sheet No. 6.3
Canceling ~~Twenty-Eighth~~Twenty-Ninth Revised Sheet No. 6.3

RATE SCHEDULE RS
RESIDENTIAL SERVICE

URSC: RS

[redacted]

AVAILABILITY:

Available throughout the entire territory served by the Company.

APPLICABILITY:

Applicable for service used for domestic purposes at an individually metered dwelling unit suitable for year-round family occupancy containing full kitchen facilities and to commonly-owned facilities in condominium and cooperative apartment buildings. Garages, pools, pumps, boat dock, etc., on the same premise as the dwelling unit are included if all such service is for personal use. Service provided hereunder shall not be shared with or resold to others.

CHARACTER OF SERVICE:

Available for single phase service from local distribution lines of the Company's system at nominal secondary voltage of 120/240 volts.

~~MONTHLY~~ RATES:

Base Charge: ~~$15.00~~0.60 per day

Energy-Demand Charge: ~~4.313~~4.884¢ per kWh

MINIMUM BILL:

In consideration of the readiness of the Company to furnish such service, a monthly minimum charge will be made of not less than the Base Charge.

DEPOSIT:

A deposit amounting to twice the estimated average monthly bill may be required before service is connected at designated premises. The deposit may be applied to any final bills against the Customer for service.

ISSUED BY: S.W. Connally, Jr.

GULF POWER
A SOUTHERN COMPANY

Section No. VI
~~Twenty-Third~~Twenty-Fourth Revised Sheet No. 6.5
Canceling ~~Twenty-Second~~Twenty-Third Revised Sheet No. 6.5

RATE SCHEDULE GS
GENERAL SERVICE – NON-DEMAND
URSC: GS

AVAILABILITY:

Available throughout the entire territory served by the Company.

APPLICABILITY:

Applicable for general lighting and power service covering the entire electrical requirements of any Customer with a demand of less than 25 kW except for service to which another Rate Schedule is applicable. Service to two or more premises shall not be combined nor shall service furnished hereunder be shared with or resold to others. All service shall be taken at the same voltage and from a single delivery point.

CHARACTER OF SERVICE:

The delivery voltage to the Customer shall be the voltage of the available distribution lines of the Company for the locality in which service is to be rendered. Three phase service may be furnished at the request of the Customer subject to the Rules and Regulations of the Company which govern the extension of three phase service.

MONTHLY RATES:

Base Charge: ~~$18.00~~21.00

Energy-Demand Charge: ~~4.884~~5.300¢ per kWh

MINIMUM MONTHLY BILLS:

In consideration of the readiness of the Company to furnish such service, no monthly bill will be rendered for less than the Base Charge.

ISSUED BY: S. W. Connally, Jr.

GULF POWER
A SOUTHERN COMPANY

Section No. VI
~~Twenty-Second~~Twenty-Third Revised Sheet No. 6.7
Canceling ~~Twenty-First~~Twenty-Second Revised Sheet No. 6.7

RATE SCHEDULE GSD
GENERAL SERVICE - DEMAND
URSC: GSD

[redacted]

AVAILABILITY:

Available throughout the entire territory served by the Company.

APPLICABILITY:

Applicable for commercial, industrial, or institutional general service on an annual basis covering the entire electrical requirements of any Customer whose highest actual measured demand is not more than four hundred ninety-nine (499) kilowatts. Service to two or more premises shall not be combined nor shall service furnished hereunder be shared with or resold to others. All service shall be taken at the same voltage, from a single delivery point, and shall be measured by a single meter.

CHARACTER OF SERVICE:

The delivery voltage to the Customer shall be the voltage of the available secondary distribution lines of the Company for the locality in which service is to be rendered. Three phase service may be furnished at the request of the Customer subject to the Rules and Regulations of the Company which govern the extension of the three phase service.

MONTHLY RATES:

Base Charge:	$44.00
Demand Charge:	~~$5.95~~6.84 per kW of billing demand
Energy Charge:	~~1.525~~1.749¢ per kWh

MINIMUM MONTHLY BILLS:

In consideration of the readiness of the Company to furnish such service, no monthly bill will be rendered for less than the Base Charge plus the Demand Charge.

ISSUED BY: S. W. Connally, Jr.

GULF POWER
A SOUTHERN COMPANY

Section No. VI
~~Twentieth~~Twenty-First Revised Sheet No. 6.8
Canceling ~~Nineteenth~~Twentieth Revised Sheet No. 6.8

[redacted]

(Continued from Rate Schedule GSD, Sheet No. 6.7)

DETERMINATION OF BILLING DEMAND:

The kilowatt (kW) billing demand for billing purposes shall be the Customer's maximum integrated fifteen (15) minute demand to the nearest kilowatt (kW) during each service month.

REACTIVE DEMAND CHARGE:

When the capacity required to be maintained is one-hundred (100) kilowatts or more, at the option of the Company, the monthly bill calculated at the above rates may be increased in the amount of $1.00 per kvar for all over 0.48432 kilovars per kilowatt (90% power factor). The kilovars to which this adjustment shall apply shall be the monthly maximum measured kilovar demand or may be calculated as the square root of the difference between the square of the maximum monthly measured kVA demand and the square of the maximum monthly measured kW demand.

TRANSFORMER OWNERSHIP DISCOUNT AND PRIMARY METERING VOLTAGE DISCOUNTS:

When the Company renders service under this Rate Schedule at the local primary distribution voltage and any transformers required are furnished by the Customer, the Monthly Rate will be subject to a discount of ~~twenty-nine~~thirty-nine (~~29~~39) cents per kW of the Customer's billing demand as determined above, and an additional discount of one percent (1%) of the Energy Charge and one percent (1%) of the Demand Charge; however, such deduction shall not reduce the minimum monthly bill specified above.

TERM OF CONTRACT:

Service under this Schedule shall be for a period of not less than one year and thereafter from year to year until terminated by three (3) months' written notice by either party to the other.

DEPOSIT:

A deposit amounting to twice the estimated average monthly bill may be required before service is connected at designated premises. The deposit may be applied to any final bills against the Customer for service.

ISSUED BY: ~~Mark Crosswhite~~S. W. Connally, Jr.

GULF POWER
A SOUTHERN COMPANY

Section No. VI
~~Twenty-Fifth~~Twenty-Sixth Revised Sheet No. 6.10
Canceling ~~Twenty-Fourth~~Twenty-Fifth Revised Sheet No. 6.10

RATE SCHEDULE LP
LARGE POWER SERVICE
URSC: GSLD

[redacted]

AVAILABILITY:

Available throughout the entire territory served by the transmission system of the Company.

APPLICABILITY:

Applicable for three phase general service on an annual basis covering the entire electrical requirements of any Customer. Service to two or more premises shall not be combined nor shall service furnished hereunder be shared with or resold to others. All service shall be taken at the same voltage, from a single delivery point, and shall be measured by a single meter.

CHARACTER OF SERVICE:

The delivery voltage to the Customer shall be the voltage of the available secondary distribution lines of the Company for the locality in which service is to be rendered.

MONTHLY RATES:

Base Charge:	~~$225.00~~250.00
Demand Charge:	~~$10.01~~12.23 per kW of billing demand
Energy Charge:	~~0.750~~0.934¢ per kWh

MINIMUM MONTHLY BILLS:

In consideration of the readiness of the Company to furnish such service, no monthly bill will be rendered for less than the Base Charge plus the Demand Charge.

ISSUED BY: S. W. Connally, Jr.

GULF POWER
A SOUTHERN COMPANY

Section No. VI
~~Twenty-Fourth~~Twenty-Fifth Revised Sheet No. 6.11
Canceling ~~Twenty-Third~~Twenty-Fourth Revised Sheet No. 6.11

(Continued from Rate Schedule LP, Sheet No. 6.10)

DETERMINATION OF BILLING DEMAND:

The kilowatt (kW) billing demand for billing purposes shall be the Customer's maximum integrated fifteen (15) minute demand to the nearest kilowatt (kW) during each service month.

REACTIVE DEMAND CHARGE:

The monthly bill calculated at the above rates shall also be increased in the amount of $1.00 per kvar for all over 0.48432 kilovars per kilowatt (90% power factor). The kilovars to which this adjustment shall apply shall be the monthly maximum measured kilovar demand or may be calculated as the square root of the difference between the square of the maximum monthly measured kVA demand and the square of the maximum monthly measured kW demand.

TRANSFORMER OWNERSHIP DISCOUNT AND PRIMARY METERING VOLTAGE DISCOUNTS:

When the Company renders service under this Rate Schedule at the local primary distribution voltage and any transformers required are furnished by the Customer, the Monthly Rate will be subject to a discount of ~~forty-one~~fifty-five (~~41~~55) cents per month per kilowatt (kW) of the Customer's billing demand as determined above, and an additional discount of one percent (1%) of the Energy Charge and one percent (1%) of the Demand Charge; however, such deduction shall not reduce the minimum monthly bill specified above.

TRANSFORMER OWNERSHIP DISCOUNT AND TRANSMISSION METERING VOLTAGE DISCOUNTS:

When the Company renders service under this Rate Schedule from an available transmission line of 46,000 volts or higher and the Customer furnishes, operates and maintains the complete step-down transformer substation necessary to receive and use such service the Monthly Rate will be subject to a discount of ~~fifty-six~~seventy-eight (~~56~~78) cents per month per kilowatt (kW) of the Customer's billing demand as determined above, and an additional discount of two percent (2%) of the Energy Charge and two percent (2%) of the Demand Charge; however, such deduction shall not reduce the minimum monthly bill specified above.

DEPOSIT:

A deposit amounting to twice the estimated average monthly bill may be required before service is connected at designated premises. The deposit may be applied to any final bills against the Customer for service.

ISSUED BY: ~~Mark Crosswhite~~S. W. Connally, Jr.

GULF POWER
A SOUTHERN COMPANY

Section No. VI
~~Twenty-First~~Twenty-Second Revised Sheet No. 6.13
Canceling ~~Twentieth~~Twenty-First Revised Sheet No. 6.13

RATE SCHEDULE PX
LARGE HIGH LOAD FACTOR POWER SERVICE
URSC: GSLD1

AVAILABILITY:

Available throughout the entire territory served by the transmission system of the Company.

APPLICABILITY:

Applicable for three phase lighting and power service to any Customer whose actual measured demand is not less than 7,500 kilowatts (kW), with an annual load factor of not less than seventy-five percent (75%). Service to two or more premises shall not be combined nor shall service furnished hereunder be shared with or resold to others. All service shall be taken at the same voltage and from a single delivery point, and shall be measured by a single meter.

CHARACTER OF SERVICE:

The delivery voltage to the Customer shall be the standard secondary voltage of the Company's transformers supplied from the transmission lines of the Company.

MONTHLY RATES:

Base Charge:	~~$646.84~~743.22
Demand Charge:	~~$9.44~~10.85 per kW of billing demand
Energy Charge:	~~0.3490~~0.399¢ per kWh

MINIMUM MONTHLY BILL:

In the event the Customer's annual load factor for the current and preceding eleven months is less than 75% and in consideration of the readiness of the Company to furnish such service, the minimum monthly bill shall not be less than the Base Charge plus ~~$11.35~~13.03 per kW of billing demand.

ISSUED BY: S.W. Connally, Jr.

GULF POWER
A SOUTHERN COMPANY

Section No. VI
~~Twenty-First~~Twenty-Second Revised Sheet No. 6.16
Canceling ~~Twentieth~~Twenty-First Revised Sheet No. 6.16

RATE SCHEDULE OS
OUTDOOR SERVICE

URSC: SL, OL, OL1, OL2

AVAILABILITY:

Available throughout the entire territory served by the Company.

OS-I/II STREET, ROADWAY, AND GENERAL AREA LIGHTING

APPLICABILITY:

Applicable for street, roadway, and general area lighting service under the provisions of the Company's standard contract for such service. Service hereunder includes power supply and may include lamp renewals and regular maintenance.

LIMITATION OF SERVICE:

Company-owned fixtures will be mounted on Company-owned poles of the Company's distribution system. Customer-owned fixtures will be mounted on Customer-owned poles, of a standard type and design, permitting service and maintenance at no abnormal cost to the Company.

MONTHLY RATES:
High Pressure Sodium Vapor

Initial Lamp Rating (Lumen)	Desc.	Lamp Wattage	Line Wattage	Est. kWh **	Fixture Charge	Maint. Charge	Energy Charge ***	Total Charge
5400*	Open Bottom	70	84	29	~~$2.91~~3.08	~~$1.57~~1.66	~~$0.67~~0.71	~~$5.15~~5.45
8800	Open Bottom	100	120	41	~~$2.49~~2.63	~~$1.42~~1.50	~~$0.95~~1.00	~~$4.86~~5.13
8800	Open Bottom w/Shield	100	120	41	~~$3.42~~3.62	~~$1.67~~1.77	~~$0.95~~1.00	~~$6.04~~6.39
8800	Acorn	100	120	41	~~$12.43~~13.14	~~$4.19~~4.43	~~$0.95~~1.00	~~$17.57~~18.57
8800	Colonial	100	120	41	~~$3.35~~3.54	~~$1.65~~1.74	~~$0.95~~1.00	~~$5.95~~6.28
8800	English Coach	100	120	41	~~$13.57~~14.34	~~$4.50~~4.76	~~$0.95~~1.00	~~$19.02~~20.10
8800	Destin Single	100	120	41	~~$23.34~~24.67	~~$7.24~~7.65	~~$0.95~~1.00	~~$31.53~~33.32
17600	Destin Double ~~$62.40~~65.97	200	240	82	~~$46.54~~49.20	~~$13.96~~14.76	~~$1.90~~2.01	
5400*	Cobrahead	70	84	29	~~$4.09~~4.32	~~$1.89~~2.00	~~$0.67~~0.71	~~$6.65~~7.03
8800	Cobrahead	100	120	41	~~$3.42~~3.62	~~$1.67~~1.77	~~$0.95~~1.00	~~$6.04~~6.39
20000*	Cobrahead	200	233	80	~~$4.71~~4.98	~~$2.05~~2.17	~~$1.85~~1.96	~~$8.61~~9.11
25000	Cobrahead	250	292	100	~~$4.58~~4.84	~~$2.02~~2.14	~~$2.31~~2.45	~~$8.91~~9.43
46000	Cobrahead	400	477	164	~~$4.82~~5.10	~~$2.08~~2.20	~~$3.79~~4.01	~~$10.69~~11.31
8800	Cutoff Cobrahead	100	120	41	~~$3.78~~4.00	~~$1.77~~1.87	~~$0.95~~1.00	~~$6.50~~6.87
25000	Cutoff Cobrahead	250	292	100	~~$4.64~~4.90	~~$2.04~~2.16	~~$2.31~~2.45	~~$8.99~~9.51
46000	Cutoff Cobrahead	400	477	164	~~$4.84~~5.12	~~$2.08~~2.20	~~$3.79~~4.01	~~$10.71~~11.33
25000	Bracket Mount CIS	250	292	100	~~$10.62~~11.23	~~$3.71~~3.92	~~$2.31~~2.45	~~$16.64~~17.60
25000	Tenon Top CIS	250	292	100	~~$10.63~~11.23	~~$3.71~~3.92	~~$2.31~~2.45	~~$16.65~~17.60

ISSUED BY: S. W. Connally, Jr.

GULF POWER
A SOUTHERN COMPANY

Section No. VI
~~Thirty-Fourth~~Thirty-Fifth Revised Sheet No. 6.16.1
Canceling ~~Thirty-Third~~Thirty-Fourth Revised
Sheet No. 6.16.1

[redacted]

(Continued from Rate Schedule OS, Sheet No. 6.16)

High Pressure Sodium Vapor (continued)

Initial Lamp Rating (Lumen)	Desc.	Lamp Wattage	Line Wattage	Est. kWh **	Fixture Charge	Maint. Charge	Energy Charge ***	Total Charge
46000	Bracket Mount CIS	400	468	161	~~$11.30~~11.94	~~$3.89~~4.11	~~$3.73~~3.94	~~$18.92~~19.99
20000*	Small ORL	200	233	80	~~$10.88~~11.50	~~$3.77~~3.98	~~$1.85~~1.96	~~$16.50~~17.44
25000	Small ORL	250	292	100	~~$10.47~~11.07	~~$3.66~~3.87	~~$2.31~~2.45	~~$16.44~~17.39
46000	Small ORL	400	477	164	~~$10.96~~11.59	~~$3.79~~4.01	~~$3.79~~4.01	~~$18.54~~19.61
20000*	Large ORL	200	233	80	~~$17.72~~18.73	~~$5.67~~5.99	~~$1.85~~1.96	~~$25.24~~26.68
46000*	Large ORL	400	477	164	~~$19.96~~21.10	~~$6.30~~6.66	~~$3.79~~4.01	~~$30.05~~31.77
46000	Shoebox	400	477	164	~~$9.15~~9.67	~~$3.29~~3.48	~~$3.79~~4.01	~~$16.23~~17.16
16000	Directional	150	197	68	~~$5.14~~5.43	~~$2.14~~2.26	~~$1.58~~1.66	~~$8.86~~9.35
20000*	Directional	200	233	80	~~$7.43~~7.85	~~$2.82~~2.98	~~$1.85~~1.96	~~$12.10~~12.79
46000	Directional	400	477	164	~~$5.52~~5.83	~~$2.28~~2.41	~~$3.79~~4.01	~~$11.59~~12.25
125000	Large Flood	1000	1105	379	~~$8.76~~9.26	~~$3.36~~3.55	~~$8.78~~9.28	~~$20.90~~22.09

Metal Halide

Initial Lamp Rating (Lumen)	Desc.	Lamp Wattage	Line Wattage	Est. kWh **	Fixture Charge	Maint. Charge	Energy Charge ***	Total Charge
12000	Acorn	175	210	72	~~$12.55~~13.27	~~$5.28~~5.58	~~$1.66~~1.76	~~$19.49~~20.61
12000	Colonial	175	210	72	~~$3.47~~3.67	~~$2.76~~2.92	~~$1.66~~1.76	~~$7.89~~8.35
12000	English Coach	175	210	72	~~$13.69~~14.47	~~$5.60~~5.92	~~$1.66~~1.76	~~$20.95~~22.15
12000	Destin Single	175	210	72	~~$23.46~~24.80	~~$8.33~~8.81	~~$1.66~~1.76	~~$33.45~~35.37
24000	Destin Double	350	420	144	~~$46.78~~49.45	~~$15.58~~16.47	~~$3.34~~3.53	~~$65.70~~69.45
32000	Small Flood	400	476	163	~~$5.64~~5.96	~~$2.44~~2.58	~~$3.77~~3.99	~~$11.85~~12.53
32000	Small Parking Lot	400	476	163	~~$10.42~~11.01	~~$3.78~~4.00	~~$3.77~~3.99	~~$17.97~~19.00
100000	Large Flood	1000	1100	378	~~$8.09~~8.55	~~$4.84~~5.12	~~$8.76~~9.25	~~$21.69~~22.92
100000	Large Parking Lot	1000	1100	378	~~$17.98~~19.01	~~$6.71~~7.09	~~$8.76~~9.25	~~$33.45~~35.35

Metal Halide Pulse Start

Initial Lamp Rating (Lumen)	Desc.	Lamp Wattage	Line Wattage	Est. kWh **	Fixture Charge	Maint. Charge	Energy Charge ***	Total Charge
13000	Acorn	150	190	65	~~$14.24~~15.05	~~$5.13~~5.42	~~$1.51~~1.59	~~$20.88~~22.06
13000	Colonial	150	190	65	~~$4.44~~4.69	~~$2.41~~2.55	~~$1.51~~1.59	~~$8.36~~8.83
13000	English Coach	150	190	65	~~$14.56~~15.39	~~$5.23~~5.53	~~$1.51~~1.59	~~$21.30~~22.51
13000	Destin Single	150	190	65	~~$30.88~~32.64	~~$9.79~~10.35	~~$1.51~~1.59	~~$42.18~~44.58
26000	Destin Double	300	380	130	~~$61.62~~65.14	~~$18.81~~19.88	~~$3.01~~3.18	~~$83.44~~88.20
33000	Small Flood	350	400	137	~~$6.32~~6.68	~~$3.11~~3.29	~~$3.17~~3.35	~~$12.60~~13.32

33000	Shoebox	350	400	137	~~$7.55~~7.98	~~$3.46~~3.66	~~$3.17~~3.35	~~$14.18~~14.99
68000	Flood	750	840	288	$6.88	$5.53	$7.05	$19.46

ISSUED BY: S. W. Connally, Jr.

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GULF POWER
A SOUTHERN COMPANY

Section No. VI
~~Twenty-Fourth~~Twenty-Fifth Revised Sheet No. 6.17
Canceling ~~Twenty-Third~~Twenty-Fourth Revised Sheet No. 6.17

[redacted]

(Continued from Rate Schedule OS, Sheet No. 6.16.1)

Combined High Pressure Sodium/Metal Halide

Initial Lamp Rating (Lumen)	Desc.	Lamp Wattage	Line Wattage	Est. kWh **	Fixture Charge	Maint. Charge	Energy Charge ***	Total Charge
20800	Destin Combo	275	330	113	~~$46.66~~49.32	~~$15.39~~16.26	~~$2.61~~2.77	~~$64.66~~68.35

Combined High Pressure Sodium/Metal Halide Pulse Start

Initial Lamp Rating (Lumen)	Desc.	Lamp Wattage	Line Wattage	Est. kWh **	Fixture Charge	Maint. Charge	Energy Charge ***	Total Charge
21800	Destin Combo PS	250	310	106	~~$54.08~~57.17	~~$16.64~~17.59	~~$2.46~~2.60	~~$73.18~~77.36

LED

~~Initial Lamp~~Nominal ~~Rating~~Delivered ~~(~~Lumen~~)~~	Desc.	Lamp Wattage	Line Wattage	Est. kWh **	Fixture Charge	Maint. Charge	Energy Charge ***	Total Charge
3776	Acorn	75	75	26	$17.66	$9.12	$0.64	$27.42
4440	Street Light	72	72	25	~~$12.97~~13.71	~~$4.44~~4.69	~~$0.58~~0.61	~~$17.99~~19.01
~~5000~~2820	Acorn A5	~~72~~56	~~72~~56	~~25~~19	~~$24.04~~25.41	~~$7.44~~7.86	~~$0.58~~0.47	~~$32.06~~33.74
5100	Cobrahead S2	73	73	25	$6.01	$3.92	$0.61	$10.54
10200	Cobrahead S3	135	135	46	$7.40	$4.52	$1.13	$13.05
~~5000~~	~~Acorn A3~~	~~72~~	~~72~~	~~25~~	~~$24.04~~	~~$7.44~~	~~$0.58~~	~~$32.06~~
~~8000~~	~~Acorn A5~~	~~112~~	~~112~~	~~38~~	~~$27.14~~	~~$8.31~~	~~$0.88~~	~~$36.33~~
~~8000~~	~~Acorn A3~~	~~112~~	~~112~~	~~38~~	~~$27.14~~	~~$8.31~~	~~$0.88~~	~~$36.33~~
~~7200~~	~~E132 A5~~	~~132~~	~~132~~	~~45~~	~~$25.94~~	~~$7.59~~	~~$1.05~~	~~$34.58~~
6320	ATB071 S2/S3	71	71	24	$7.49	$5.10	$0.59	$13.18
9200	ATB1 105 S3	105	105	36	$10.95	$6.15	$0.88	$17.98
23240	ATB2 280 S4	280	280	96	$12.39	$7.15	$2.35	$21.89
7200	E132 A3	132	132	45	~~$25.94~~27.42	~~$7.59~~8.03	~~$1.05~~1.10	~~$34.58~~36.55
9600	E157 SAW	157	157	54	~~$17.56~~18.56	~~$5.24~~5.54	~~$1.25~~1.32	~~$24.05~~25.42
7377	WP9 A2/S2	140	140	48	$41.70	$13.82	$1.18	$56.70
7614	Destin Single	105	105	36	$32.05	$15.38	$0.88	$48.31
15228	Destin Double	210	210	72	$63.82	$30.53	$1.76	$96.11

~~Mercury Vapor~~
~~(Not Available for New Installations)~~

~~Initial Lamp Rating (Lumen)~~	~~Desc.~~	~~Lamp Wattage~~	~~Line Wattage~~	~~Est. kWh **~~	~~Fixture Charge~~	~~Maint. Charge~~	~~Energy Charge ***~~	~~Total Charge~~

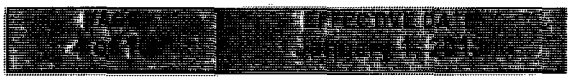
7000*	Open Bottom	175	195	67	$2.02	$1.25	$1.55	$4.82
3200*	Cobrahead	100	114	39	$3.75	$1.76	$0.90	$6.41
7000*	Cobrahead	175	195	67	$3.41	$1.64	$1.55	$6.60
9400*	Cobrahead	250	277	95	$4.47	$2.00	$2.20	$8.67
17000*	Cobrahead	400	442	152	$4.88	$2.08	$3.52	$10.48
48000*	Cobrahead	1000	1084	372	$9.80	$3.61	$8.61	$22.02
17000*	Directional	400	474	163	$7.35	$2.78	$3.77	$13.90

* Not Available for New Installation.
** Estimated Monthly kWh = (Line Wattage x Annual Operating Hours)/(1000 x 12)
*** Energy Charge = 2.316¢/kWh x Estimated Monthly kWh Usage

ISSUED BY: S. W. Connally, Jr.

GULF POWER
A SOUTHERN COMPANY

Section No. VI
~~Twenty-Sixth~~Twenty-Seventh Revised Sheet No. 6.18
Canceling ~~Twenty-Fifth~~Twenty-Sixth Revised Sheet No. 6.18



(Continued from Rate Schedule OS, Sheet No. 6.17)

Mercury Vapor
(Not Available for New Installations)

Initial Lamp Rating (Lumen)	Desc.	Lamp Wattage	Line Wattage	Est. kWh **	Fixture Charge	Maint. Charge	Energy Charge ***	Total Charge
7000*	Open Bottom	175	195	67	$2.14	$1.32	$1.64	$5.10
3200*	Cobrahead	100	114	39	$3.96	$1.86	$0.95	$6.77
7000*	Cobrahead	175	195	67	$3.60	$1.73	$1.64	$6.97
9400*	Cobrahead	250	277	95	$4.73	$2.11	$2.33	$9.17
17000*	Cobrahead	400	442	152	$5.16	$2.20	$3.72	$11.08
48000*	Cobrahead	1000	1084	372	$10.36	$3.82	$9.11	$23.29
17000*	Directional	400	474	163	$7.77	$2.94	$3.99	$14.70

* Not Available for New Installation.
** Estimated Monthly kWh = (Line Wattage x Annual Operating Hours)/(1000 x 12)
*** Energy Charge = 2.448¢/kWh x Estimated Monthly kWh Usage

ADDITIONAL FACILITIES CHARGES:

The above rates apply to lighting installations made on the Company's existing overhead distribution system. Any special or additional facilities, which may be installed at the Company's option, will be billed in addition to the above rates.

Charge for 13 ft. decorative concrete pole used only for decorative lights (Colonial, Acorn, or English Coach) ~~$15.95~~17.17.
Charge for 13 ft. decorative high gloss concrete pole used only for decorative lights. (Colonial, Acorn, or English Coach) $15.55.
Charge for 16 ft. decorative base aluminum pole with 6" Tenon used only for decorative lights (Destin Single or Double) $12.32.
Charge for 17 ft. decorative base aluminum pole used only for decorative lights (Colonial, Acorn, or English Coach) ~~$16.72~~17.99.
Charge for 20 ft. fiberglass pole used only for decorative lights (Colonial) ~~$5.92~~6.37.
Charge for 20 ft. (16 ft. mounting height) aluminum, round, tapered pole (Spun Tenon) $5.61.
Charge for 20 ft. (16 ft. mounting height) aluminum, round, tapered pole (Welded Tenon) $19.09.
Charge for 25 ft. (20 ft. mounting height) aluminum, round, tapered pole $19.95.
Charge for 30 ft. wood pole ~~$3.83~~4.12.
Charge for 30 ft. concrete pole ~~$8.03~~8.64.
Charge for 30 ft. fiberglass pole with concrete, anchor-based pedestal used primarily for the 100,000 Lumen Large Parking Lot fixture ~~$38.01~~40.91.
Charge for 30 ft. (25 ft. mounting height) aluminum, round, tapered pole $22.13.
Charge for 35 ft. concrete pole ~~$11.70~~12.59.
Charge for 35 ft. concrete pole (Tenon Top) ~~$16.15~~17.38.

~~Charge for 35 ft. wood pole $5.58.~~
~~Charge for 40 ft. wood pole $6.86.~~
~~Charge for 45 ft. concrete pole (Tenon Top) $21.20.~~
~~Charge for single arm for Shoebox/Small Parking Lot fixture $2.22.~~
~~Charge for double arm for Shoebox/Small Parking Lot fixture $2.47.~~
~~Charge for triple arm for Shoebox/Small Parking Lot fixture $3.34.~~
~~Charge for quadruple arm for Shoebox/Small Parking Lot fixture $4.21.~~
~~Charge for Tenon Top adapter for 100,000 Lumen Large Parking Lot fixture $4.11.~~
~~Charge for optional 100 amp relay $22.97.~~
~~Charge for 25 kVA transformer (non-coastal) for 46,000 Lumen Shoebox, 32,000 Lumen Small Parking Lot, or 100,000 Lumen Large Parking Lot fixture(s) $31.79.~~
~~Charge for 25 kVA transformer (coastal) for 46,000 Lumen Shoebox, 32,000 Lumen Small Parking Lot, or 100,000 Lumen Large Parking Lot fixture(s) $45.30.~~

~~All other additional facilities shall be billed at 1.74% per month of the Company's cost. Such facilities may include, but are not limited to, additional overhead or underground wiring and special poles approved by the Company.~~

ISSUED BY: S. W. Connally, Jr.

GULF POWER
A SOUTHERN COMPANY

Section No. VI
~~Twenty-Second~~Twenty-Third Revised Sheet No. 6.19
Canceling ~~Twenty-First~~Twenty-Second Revised Sheet No. 6.19

(Continued from Rate Schedule OS, Sheet No. 6.18)

ADDITIONAL FACILITIES CHARGES (continued):

Charge for 35 ft. wood pole $6.01.
Charge for 35 ft. (30 ft. mounting height) aluminum, round, tapered pole $24.78.
Charge for 40 ft. wood pole $7.38.
Charge for 45 ft. concrete pole (Tenon Top) $22.81.
Charge for single arm for Shoebox/Small Parking Lot fixture $2.39.
Charge for double arm for Shoebox/Small Parking Lot fixture $2.66.
Charge for triple arm for Shoebox/Small Parking Lot fixture $3.59.
Charge for quadruple arm for Shoebox/Small Parking Lot fixture $4.53.
Charge for Tenon Top adapter for 100,000 Lumen Large Parking Lot fixture $4.42.
Charge for optional 100 amp relay $24.72.
Charge for 25 kVA transformer (non-coastal) for 46,000 Lumen Shoebox, 32,000 Lumen Small Parking Lot, or 100,000 Lumen Large Parking Lot fixture(s) $34.21.
Charge for 25 kVA transformer (coastal) for 46,000 Lumen Shoebox, 32,000 Lumen Small Parking Lot, or 100,000 Lumen Large Parking Lot fixture(s) $48.75.

All other additional facilities shall be billed at 1.74% per month of the Company's cost. Such facilities may include, but are not limited to, additional overhead or underground wiring and special poles approved by the Company.

VANDALISM (WILLFUL DAMAGE):

The Customer will have the following three options on the second occurrence of vandalism (willful damage) to a Company fixture:

1. Pay (a) the total repair costs of the fixture or the original total installed cost of the fixture less any depreciation and salvage value plus the removal cost if the fixture cannot be repaired and (b) the total installed cost of a luminaire protective shield. If the fixture is not compatible with the shield, then the fixture will be replaced with either a compatible 100 watt or 250 watt cobrahead fixture,

2. Request that the damaged fixture be replaced with the same type of unshielded fixture. For this and any subsequent occurrence, the Customer will pay either (a) the total repair costs of the fixture or (b) the original total installed cost of the fixture less any depreciation and salvage value plus the removal cost if the fixture cannot be repaired, or

3. Discontinue the service to the fixture.

The Customer must notify the Company in writing of its selected option. The Customer may choose to pay the total installed cost of a luminaire protective shield after the first occurrence of vandalism (willful damage) to a Company fixture and save the costs incurred in 1(a) above.

~~**MONTHLY RATES - CUSTOMER OWNED WITHOUT RELAMPING SERVICE AGREEMENT:**~~

~~Customer-owned street, roadway, and general area lighting fixtures which conform to the specifications of Company-owned fixtures may receive energy at the appropriate charges for each size light above. Customer-owned street, roadway, and general area lighting systems which do not conform to specifications of the Company-owned fixtures shall be charged the monthly rate of 2.316¢/kWh of the estimated kWh usage of each unit. Customer-owned equipment must be approved in advance as to accessibility to be eligible to receive service. The Customer will provide all pole(s), fixture(s), lamp(s), photoelectric control(s), and circuit(s) up to the point of connection to the Company's supply lines (point of service), and an adequate support for the Company-owned service conductors. The Company will provide an overhead service drop from its existing secondary conductors to the point of service designated by the Company for Customer-owned lights. Underground service conductors will be installed in lieu of the overhead conductors at the Customer's request, and upon payment by the Customer of the installed cost of the underground conductors after allowance for the cost of equivalent overhead service conductors and any trenching and backfilling provided by the Customer. The distribution system shall serve no other electrical loads except the lighting equipment eligible for this rate.~~

GULF POWER
A SOUTHERN COMPANY

Section No. VI
~~Twenty-Third~~Twenty-Fourth Revised Sheet No. 6.20
Canceling ~~Twenty-Second~~Twenty-Third Revised Sheet No. 6.20

(Continued from Rate Schedule OS, Sheet No. 6.19)

MONTHLY RATES - CUSTOMER OWNED WITHOUT RELAMPING SERVICE AGREEMENT:

Customer-owned street, roadway, and general area lighting fixtures which conform to the specifications of Company-owned fixtures may receive energy at the appropriate charges for each size light above. Customer-owned street, roadway, and general area lighting systems which do not conform to specifications of the Company-owned fixtures shall be charged the monthly rate of 2.448¢/kWh of the estimated kWh usage of each unit. Customer-owned equipment must be approved in advance as to accessibility to be eligible to receive service. The Customer will provide all pole(s), fixture(s), lamp(s), photoelectric control(s), and circuit(s) up to the point of connection to the Company's supply lines (point of service), and an adequate support for the Company-owned service conductors. The Company will provide an overhead service drop from its existing secondary conductors to the point of service designated by the Company for Customer-owned lights. Underground service conductors will be installed in lieu of the overhead conductors at the Customer's request, and upon payment by the Customer of the installed cost of the underground conductors after allowance for the cost of equivalent overhead service conductors and any trenching and backfilling provided by the Customer. The distribution system shall serve no other electrical loads except the lighting equipment eligible for this rate.

MONTHLY RATES - CUSTOMER OWNED WITH RELAMPING SERVICE AGREEMENT:

The monthly rates set forth below cover both the electric service (if unmetered) and the replacement of lamps and photoelectric controls upon routine failure. Lamps or photoelectric controls damaged or destroyed due to vandalism or willful abuse are not covered by the agreement and will only be replaced at the Customer's expense. Customer-owned equipment must be approved in advance as to compatibility with Company-owned lamps and photoelectric controls and accessibility to be eligible to receive service. The Customer will provide all pole(s), fixture(s), initial lamp(s) and photoelectric control(s), and circuit(s) up to the point of connection to the Company's supply lines (point of service), and an adequate support for the Company-owned service conductors. The Company will provide an overhead service drop from its existing secondary conductors to the point of service designated by the Company for Customer-owned lights. Underground service conductors will be installed in lieu of the overhead conductors at the Customer's request, and upon payment by the Customer of the installed cost of the underground conductors after allowance for the cost of equivalent overhead service conductors and any trenching and backfilling provided by the Customer. The distribution system shall serve no other electrical loads except the lighting equipment eligible for this rate. The Customer remains responsible for all maintenance other than the replacement of lamps and photoelectric controls.

~~**MONTHLY RATES - CUSTOMER OWNED WITH RELAMPING SERVICE AGREEMENT:**~~

~~**High Pressure Sodium Vapor**~~

Initial Lamp Rating (Lumen)	Lamp Wattage	Line Wattage	Est. kWh **	Relamping Charge	Energy Charge ***	Total Charge
8800	100	120	41	$0.64	$0.95	$1.59
16000	150	197	68	$0.63	$1.58	$2.21
20000*	200	233	80	$0.65	$1.85	$2.50
25000	250	292	100	$0.66	$2.31	$2.97
46000	400	477	164	$0.65	$3.79	$4.44
125000	1000	1105	379	$0.83	$8.78	$9.61

ISSUED BY: S.W. Connally, Jr.

Schedule E-14
Docket No. 130140-EI
Page 36 of 74

GULF POWER
A SOUTHERN COMPANY

Section No. VI
~~Twenty-Third~~Twenty-Fourth Revised Sheet No. 6.21
Canceling ~~Twenty-Second~~Twenty-Third Revised Sheet No. 6.21

[redacted]

(Continued from Rate Schedule OS, Sheet No. 6.20)

MONTHLY RATES - CUSTOMER OWNED WITH RELAMPING SERVICE AGREEMENT:

High Pressure Sodium Vapor

Initial Lamp Rating (Lumen)	Lamp Wattage	Line Wattage	Est. kWh **	Relamping Charge	Energy Charge ***	Total Charge
8800	100	120	41	$0.68	$1.00	$1.68
16000	150	197	68	$0.67	$1.66	$2.33
20000*	200	233	80	$0.69	$1.96	$2.65
25000	250	292	100	$0.70	$2.45	$3.15
46000	400	477	164	$0.69	$4.01	$4.70
125000	1000	1105	379	$0.88	$9.28	$10.16

Metal Halide

Initial Lamp Rating (Lumen)	Lamp Wattage	Line Wattage	Est. kWh **	Relamping Charge	Energy Charge ***	Total Charge
32000	400	476	163	~~$0.78~~0.82	~~$3.77~~3.99	~~$4.55~~4.81

LED

Initial Lamp Rating (Lumen)	Lamp Wattage	Line Wattage	Est. kWh **	Relamping Charge	Energy Charge ***	Total Charge
4440	72	72	25	~~$0.73~~0.77	~~$0.58~~0.61	~~$1.31~~1.38

* Not Available for New Installation
** Estimated Monthly kWh = (Line Wattage x Annual Operating Hours)/(1000 x 12)
*** Energy Charge = ~~2.316~~2.448¢/kWh x Estimated Monthly kWh Usage

The Total Charge shown above is for an unmetered fixture. If the service is metered, there will be no Energy Charge billed under this rate.

ADDITIONAL FACILITIES CHARGES FOR CUSTOMER OWNED:

Any special or additional facilities, which may be installed at the Company's option, will be billed in addition to the above Customer-owned rates.

Charge for 35 ft. wood pole ~~$5.58~~6.01.

All other additional facilities shall be billed at 1.74 percent per month of the Company's cost.

~~PROVISION FOR UP FRONT PAYMENT OF ADDITIONAL FACILITIES:~~

~~At the Customer's option, the cost of the additional facilities may be paid up front in lieu of a monthly charge. Should the Customer choose this method of payment, the amount will be the Company's total installed cost for these additional facilities for overhead or underground distribution electric service. The Company will retain ownership of these additional facilities.~~

~~The useful life of the pole(s) is 30 years from the installation date; and the useful life of the wire, eyebolts, and other miscellaneous additional facilities is 15 years from the installation date. If the pole(s), wire, eyebolts and/or other miscellaneous additional facilities must be changed out prior to this date, the facilities will be changed out at no cost to the Customer; and the billing of these facilities will remain as is. However, if any of these facilities have to be changed out on or after this date, then the Customer will have the option of one of three billing methods for the additional facilities that are replaced: (1) paying up front for the total installed cost of the replacement of the additional facilities, (2) paying a monthly charge as provided in the tariff, or (3) discontinuing the unmetered electric service.~~

ISSUED BY: S. W Connally, Jr.

GULF POWER
A SOUTHERN COMPANY

Section No. VI
~~Seventeenth~~Eighteenth Revised Sheet No. 6.22
Canceling ~~Sixteenth~~Seventeenth Revised Sheet No. 6.22

(Continued from Rate Schedule OS, Sheet No. 6.21)

PROVISION FOR UP FRONT PAYMENT OF ADDITIONAL FACILITIES:

At the Customer's option, the cost of the additional facilities may be paid up front in lieu of a monthly charge. Should the Customer choose this method of payment, the amount will be the Company's total installed cost for these additional facilities for overhead or underground distribution electric service. The Company will retain ownership of these additional facilities.

The useful life of the pole(s) is 30 years from the installation date; and the useful life of the wire, eyebolts, and other miscellaneous additional facilities is 15 years from the installation date. If the pole(s), wire, eyebolts and/or other miscellaneous additional facilities must be changed out prior to this date, the facilities will be changed out at no cost to the Customer; and the billing of these facilities will remain as is. However, if any of these facilities have to be changed out on or after this date, then the Customer will have the option of one of three billing methods for the additional facilities that are replaced: (1) paying up front for the total installed cost of the replacement of the additional facilities, (2) paying a monthly charge as provided in the tariff, or (3) discontinuing the unmetered electric service.

PROVISION FOR UP FRONT PAYMENT OF FIXTURES:

At the Customer's option, the cost of the fixture(s) may be paid up front in lieu of paying the monthly Total Charge of the fixture(s). Should the Customer choose this method of payment, the amount will be the Company's total installed cost for the fixture(s). The Company will retain ownership of the fixture(s) and will provide for any routine maintenance. On a monthly basis, the Customer will pay only the Maintenance and Energy Charges for the fixture(s) in lieu of the total of the Fixture, Maintenance, and Energy Charges.

The useful life of the fixture(s) is 15 years from the installation date. If the fixture(s) fails prior to this date, the fixture(s) will be changed out at no cost to the Customer; and the billing of fixture(s) will remain as is. However, if the fixture(s) fails on or after this date, then the Customer will have the option of one of three billing methods for the fixture(s) that is replaced: (1) paying up front for the total installed cost of the replacement of the fixture(s) and continuing to pay on a monthly basis the Maintenance and Energy Charges for the fixture(s), (2) paying the monthly Total Charge of the fixture(s) as provided in the tariff, or (3) discontinuing the unmetered electric service.

PROVISION FOR CHANGING TO DIFFERENT FIXTURE BEFORE CONTRACT EXPIRES:

The Company will change out a fixture(s) currently being billed to a customer to a different type of fixture(s) at no cost after the expiration of the initial contract term. If a Customer requests that the change out be made prior to the end of the initial contract term, the Customer will be billed labor and overhead costs for the removal of the old fixture or parts necessary for the conversion (lamp, ballast, etc.) and the installation of the new fixture or parts necessary for the conversion (lamp, ballast, etc.). The Customer will then begin paying the price in the tariff applicable to the new fixture(s) that was installed.

~~OS-III. OTHER OUTDOOR SERVICE (OL1)~~

~~Other outdoor service for Customer-owned facilities with fixed wattage loads operating continuously throughout the billing period such as, but not limited to, traffic signals and cable television amplifiers shall be billed according to the monthly rate below:~~

~~4.365 cents per kWh for all kWh~~

~~The estimated annual kWh usage shall be determined by multiplying the annual operation hours times the maximum demand. The monthly kWh usage will be one-twelfth (1/12) of the estimated annual kWh usage. Maximum demand shall be the total number of kilowatts connected at any one time. At the option of the Company service rendered under this section may be metered and billed under the applicable General Service rate schedule. Minimum Monthly bill shall be $1.00 per service connection.~~

ISSUED BY: S. W. Connally, Jr.

GULF POWER
A SOUTHERN COMPANY

Section No. VI
~~Eighteenth~~Nineteenth Revised Sheet No. 6.23
Canceling ~~Seventeenth~~Eighteenth Revised Sheet No. 6.23

(Continued from Rate Schedule OS, Sheet No. 6.22)

OS-III. OTHER OUTDOOR SERVICE (OL1)

Other outdoor service for Customer-owned facilities with fixed wattage loads operating continuously throughout the billing period such as, but not limited to, traffic signals and cable television amplifiers shall be billed according to the monthly rate below:

4.614 cents per kWh for all kWh

The estimated annual kWh usage shall be determined by multiplying the annual operation hours times the maximum demand. The monthly kWh usage will be one-twelfth (1/12) of the estimated annual kWh usage. Maximum demand shall be the total number of kilowatts connected at any one time. At the option of the Company service rendered under this section may be metered and billed under the applicable General Service rate schedule. Minimum Monthly bill shall be $1.00 per service connection.

TERM OF CONTRACT (OS-I/II, OS-III):

Service under this Rate Schedule shall be for an initial period of ~~five (5) years for high pressure sodium street lighting under the terms of Part I/II, three (3) years for high pressure sodium vapor (non-residential) or metal halide (non-residential) general area lighting under terms of Part I/II, two (2) years for high pressure sodium vapor (residential) general area lighting under terms of Part I/II, and in each case thereafter from year to year until terminated by three (3) months written notice~~not less than three (3) years and shall remain until terminated by notice to either party ~~to~~by the other. When additional facilities are required, the Company may require a contract for a longer initial period. There is no term of contract for rate OS-III.

DEPOSIT (OS-I/II, OS-III):

A deposit amounting to not over one-half the billing for the initial contract period may be required before service is connected. The deposit may be applied to any final bills against the Customer for service.

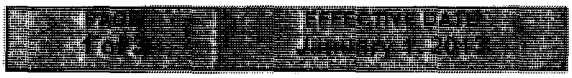
ISSUED BY: ~~Mark Crosswhite~~S. W. Connally, Jr.

GULF POWER
A SOUTHERN COMPANY

Section No. VI
~~Eighth~~Ninth Revised Sheet No. 6.42
Canceling ~~Seventh~~Eighth Revised Sheet No. 6.42

RATE SCHEDULE GSTOU
GENERAL SERVICE TIME-OF-USE CONSERVATION (OPTIONAL SCHEDULE)

URSC: GSTOU



AVAILABILITY:

Available on a first come - first serve basis subject to meter availability throughout the entire territory served by the Company.

APPLICABILITY:

Applicable as an option to Rate Schedule GSD for general service on an annual basis covering the entire electrical requirements of any Customer whose highest actual measured demand is not more than four hundred ninety-nine (499) kilowatts. Service to two or more premises shall not be combined nor shall service furnished hereunder be shared with or resold to others. All service shall be taken at the same voltage, from a single delivery point, and shall be measured by a single meter.

CHARACTER OF SERVICE:

The delivery voltage to the Customer shall be the voltage of the available secondary distribution lines of the Company for the locality in which service is to be rendered. Three phase service may be furnished at the request of the Customer subject to the Rules and Regulations of the Company which govern the extension of the three phase service.

MONTHLY RATES:

Base Charge: $44.00

Energy Charges:

Summer – June through September:
On-Peak ~~16.391~~18.691¢ per kWh
Intermediate ~~6.1196~~6.978¢ per kWh
Off-Peak ~~2.5452~~.902¢ per kWh

October through May:
All hours ~~3.562~~4.062¢ per kWh

ISSUED BY: S. W. Connally, Jr.

GULF POWER
A SOUTHERN COMPANY

Section No. VI
~~Fourth~~Fifth Revised Sheet No. 6.46
Canceling ~~Third~~Fourth Revised Sheet No. 6.46

(Continued from Rate Schedule GSDT, Sheet No. 6.45)

MONTHLY RATES:

Base Charge:	$44.00
Demand Charge:	~~$2.82~~3.24 per kW of maximum demand plus; ~~$3.18~~3.66 per kW of on-peak demand
Energy Charge:	~~1.525~~1.749¢ per kWh

CRITICAL PEAK OPTION – Under this option, the Demand Charge shall be:

Demand Charge:	~~$2.82~~3.24 per kW of maximum demand plus; ~~$1.59~~1.83 per kW of on-peak demand plus, ~~$4.77~~5.49 per kW of critical peak demand

MINIMUM MONTHLY BILLS:

In consideration of the readiness of the Company to furnish such service, no monthly bill will be rendered for less than the Base Charge plus the Demand Charge.

DETERMINATION OF THE ON-PEAK PERIOD:

The on-peak period for calendar months April through October is defined as being those hours between 12:00 p.m. and 9:00 p.m. Central Daylight Time/Central Standard Time, Monday through Friday.

The on-peak period for calendar months November through March is defined as being those hours between 6:00 a.m. and 10:00 a.m. and between 6:00 p.m. and 10:00 p.m. Central Standard Time/Central Daylight Time, Monday through Friday.

ISSUED BY: S. W. Connally, Jr.

GULF POWER
A SOUTHERN COMPANY

Section No. VI
~~Third~~Fourth Revised Sheet No. 6.48
Canceling ~~Second~~Third Revised Sheet No. 6.48

(Continued from Rate Schedule GSDT, Sheet No. 6.47)

TRANSFORMER OWNERSHIP DISCOUNT AND PRIMARY METERING VOLTAGE DISCOUNTS:

When the Company renders service under this Rate Schedule at the local primary distribution voltage and any transformers required are furnished by the Customer, the Monthly Rate will be subject to a discount of ~~twenty-nine~~thirty-nine (~~29~~39) cents per kW of the Customer's Maximum Demand as determined above, and an additional discount of one percent (1%) of the Energy Charge and one percent (1%) of the Demand Charge; however, such deduction shall not reduce the minimum monthly bill specified above.

CRITICAL PEAK DEMAND NOTIFICATION

A customer electing the critical peak option will be notified of a critical peak period one business day prior to the beginning of the critical peak period event. The Company is not responsible for a customer's failure to receive and act upon the critical peak period. If a customer does not receive these notifications, it is the customer's responsibility to inform the Company so the notifications may be supplied.

TERM OF CONTRACT:

(1) Service under this Schedule shall be for a period of not less than one year and thereafter from year to year until terminated by three (3) months' written notice by either party to the other.

(2) The initial selection of this optional rate schedule by a Rate Schedule GSD Customer may be terminated at any time by written or personal notice from the Customer. After such termination, any subsequent selection of this option by the same Customer for service at the same premises shall have a term of contract as specified in (1) above.

ISSUED BY: ~~Mark Crosswhite~~S. W. Connally, Jr.

GULF POWER
A SOUTHERN COMPANY

Section No. VI
~~Fourth~~Fifth Revised Sheet No. 6.49
Canceling ~~Third~~Fourth Revised Sheet No. 6.49

RATE SCHEDULE LPT
LARGE POWER SERVICE – TIME-OF-USE CONSERVATION (OPTIONAL SCHEDULE)

URSC: GSLDT

[redacted]

AVAILABILITY:

Available on a first come - first serve basis subject to meter availability throughout the entire territory served by the transmission system of the Company.

APPLICABILITY:

Applicable as an option to Rate Schedule LP for three phase general service on an annual basis covering the entire electrical requirements of any Customer. Service to two or more premises shall not be combined nor shall service furnished hereunder be shared with or resold to others. All service shall be taken at the same voltage, from a single delivery point, and shall be measured by a single meter. Customers taking service under Rate LPT may elect the critical peak option.

CHARACTER OF SERVICE:

The delivery voltage to the Customer shall be the voltage of the available secondary distribution lines of the Company for the locality in which service is to be rendered.

MONTHLY RATES:

Base Charge:	~~$225.00~~250.00
Demand Charge:	~~$2.00~~2.54 per kW of maximum demand plus; ~~$8.04~~9.84 per kW of on-peak demand
Energy Charge:	~~0.7500~~0.934¢ per kWh

ISSUED BY: S. W. Connally, Jr.

GULF POWER
A SOUTHERN COMPANY

Section No. VI
~~Second~~Third Revised Sheet No. 6.50
Canceling ~~First~~Second Sheet No. 6.50

(Continued from Rate Schedule LPT, Sheet No. 6.49)

CRITICAL PEAK OPTION –Under this option, the Demand Charge shall be:

Demand Charge: ~~$2.00~~2.54 per kW of maximum demand plus;
~~$4.02~~4.92 per kW of on-peak demand plus,
~~$12.06~~14.76 per kW of critical peak demand

MINIMUM MONTHLY BILLS:

In consideration of the readiness of the Company to furnish such service, no monthly bill shall be rendered for less than the Base Charge plus the Demand Charge.

DETERMINATION OF THE ON-PEAK PERIOD:

The on-peak period for calendar months April through October is defined as being those hours between 12:00 p.m. and 9:00 p.m. Central Daylight Time/Central Standard Time, Monday through Friday.

The on-peak period for calendar months November through March is defined as being those hours between 6:00 a.m. and 10:00 a.m. and between 6:00 p.m. and 10:00 p.m. Central Standard Time/Central Daylight Time, Monday through Friday.

DETERMINATION OF THE OFF-PEAK PERIOD:

All hours not included above and all hours of the observed holidays of New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving, and Christmas are in the off-peak period.

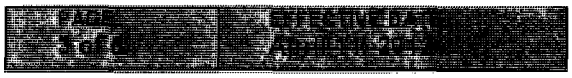
DETERMINATION OF CRITICAL PEAK PERIOD:

A critical peak period may be designated at any time at the Company's discretion. The duration of any single critical peak period may range from 1 to 2 hours in length. The total number of hours designated as critical peak periods may not exceed 87 hours per year. The total number of critical peak periods may not exceed one per day, and may not exceed four per week. Conditions which may result in the designation of a critical peak period by the Company include, but are not limited to: (i) A temperature forecast for the Company's service area that is above 95°F or below 32°F; (ii) Real-Time-Prices that exceed certain thresholds; (iii) Projections of system peak loads that exceed certain thresholds.

ISSUED BY: S. W. Connally, Jr.

GULF POWER
A SOUTHERN COMPANY

Section No. VI
~~Second~~Third Revised Sheet No. 6.51
Canceling ~~First~~Second Revised Sheet No. 6.51



(Continued from Rate Schedule LPT, Sheet No. 6.50)

DETERMINATION OF BILLING DEMAND:

(a) Maximum Demand--The kilowatt (kW) billing demand for billing purposes shall be the Customer's maximum integrated 15 minute demand to the nearest kilowatt (kW) during each service month.

(b) On-Peak Demand--The kilowatt (kW) billing demand for billing purposes shall be the Customer's maximum integrated 15 minute demand to the nearest kilowatt (kW) during each service month as measured during the hours designated as on-peak.

(c) Critical Peak Demand – The kilowatt (kW) billing demand for billing purposes shall be the Customer's maximum integrated 15 minute demand to the nearest kilowatt (kW) during each service month as measured during the hours designated as critical peak.

REACTIVE DEMAND CHARGE:

The monthly bill calculated at the above rates may be increased in the amount of $1.00 per kvar for all over 0.48432 kilovars per kilowatt (90% power factor). The kilovars to which this adjustment shall apply shall be the monthly maximum measured kilovar demand or may be calculated as the square root of the difference between the square of the maximum monthly measured kVA demand and the square of the maximum monthly measured kW demand.

TRANSFORMER OWNERSHIP DISCOUNT AND PRIMARY METERING VOLTAGE DISCOUNTS:

When the Company renders service under this Rate Schedule at the local primary distribution voltage and any transformers required are furnished by the Customer, the Monthly Rate will be subject to a discount of ~~forty-one~~fifty-five (~~41~~55) cents per month per kilowatt (kW) of the Customer's highest billing demand as determined above, and an additional discount of one percent (1%) of the Energy Charge and one percent (1%) of the Demand Charge; however, such deduction shall not reduce the minimum monthly bill specified above.

ISSUED BY: ~~Mark Crosswhite~~S. W. Connally, Jr.

GULF POWER
A SOUTHERN COMPANY

Section No. VI
~~Second~~Third Revised Sheet No. 6.52
Canceling ~~First~~Second Revised Sheet No. 6.52

(Continued from Rate Schedule LPT, Sheet No. 6.51)

TRANSFORMER OWNERSHIP DISCOUNT AND TRANSMISSION METERING VOLTAGE DISCOUNTS:

When the Company renders service under this Rate Schedule from an available transmission line of 46,000 volts or higher and the Customer furnishes, operates, and maintains the complete step-down transformer substation necessary to receive and use such service, the Monthly Rate will be subject to a discount of ~~fifty-six~~seventy-eight (~~56~~78) cents per month per kilowatt (kW) of the Customer's highest billing demand as determined above, and an additional discount of two percent (2%) of the Energy Charge and two percent (2%) of the Demand Charge; however, such deduction shall not reduce the minimum monthly bill specified above.

DEPOSIT:

A deposit amounting to twice the estimated average monthly bill may be required before service is connected at designated premises. The deposit may be applied to any final bills against the Customer for service.

CRITICAL PEAK DEMAND NOTIFICATION

A customer electing the critical peak option will be notified of a critical peak period one business day prior to the beginning of the critical peak period event. The Company is not responsible for a customer's failure to receive and act upon the critical peak period. If a customer does not receive these notifications, it is the customer's responsibility to inform the Company so the notifications may be supplied.

TERM OF CONTRACT:

(1) Service under this Schedule shall be for a period of not less than one year and thereafter from year to year until terminated by three (3) months' written notice by either party to the other.

(2) The initial selection of this rate schedule as an option by a Rate Schedule LP Customer may be terminated at any time by written or personal notice from the Customer. After such termination, any subsequent selection of this option by the same Customer for service at the same premises shall have a term of contract as specified in (1) above.

ISSUED BY: ~~Mark Crosswhite~~S. W. Connally, Jr.

GULF POWER
A SOUTHERN COMPANY

Section No. VI
~~Fourth~~Fifth Revised Sheet No. 6.53
Canceling ~~Third~~Fourth Revised Sheet No. 6.53

RATE SCHEDULE PXT
LARGE HIGH LOAD FACTOR POWER SERVICE TIME-OF-USE CONSERVATION (OPTIONAL SCHEDULE)

URSC: GSLDT1

[redacted]

AVAILABILITY:

Available throughout the entire territory served by the transmission system of the Company.

APPLICABILITY:

Applicable as an option to Rate Schedule PX for three phase lighting and power service to any customer whose actual measured demand is not less than 7,500 kilowatts (kW), with an annual load factor of not less than seventy-five percent (75%). Service to two or more premises shall not be combined nor shall service furnished hereunder be shared with or resold to others. All service shall be taken at the same voltage and from a single delivery point, and shall be measured by a single meter.

CHARACTER OF SERVICE:

The delivery voltage to the Customer shall be the standard secondary voltage of the Company's transformers supplied from the transmission lines of the Company.

MONTHLY RATES:

Base Charge:	~~$646.84~~743.22
Demand Charge:	~~$0.78~~0.90 per kW of maximum demand plus; ~~$8.76~~10.07 per kW of on-peak demand
Energy Charge:	On-Peak and Off-Peak Period: ~~0.345~~0.399¢ per kWh

ISSUED BY: S. W. Connally, Jr.

Section VII
~~Fifth~~Sixth Revised Sheet No. 7.14
Canceling ~~Fourth~~Fifth Revised Sheet No. 7.14

Form 4 (Continued)

SECTION B - POLES AND ADDITIONAL FACILITIES

Total Unit Cost	
Material Cost of Pole or Additional Facility	$0.00
0.000 Man-hours to Install Pole/Additional Facility @ ~~$52.70~~53.28/Manhour	$0.00
SUBTOTAL	$0.00
~~30~~36.0% Engineering & Supervision Overheads	$0.00
UNIT COST TOTAL	$0.00
Pole/Additional Facility Charge	
Fixed Charge = (15.235% x Unit Cost Total)/12 Months	$0.00
Revenue Tax = Fixed Charge x 0.000721	$0.00
~~MONTHLY POLE/ADDITIONAL FACILITY CHARGE PER UNIT~~	~~$0.00~~
MONTHLY POLE/ADDITIONAL FACILITY CHARGE PER UNIT	**$0.00**

ISSUED BY: ~~Mark Crosswhite~~S. W. Connally, Jr. EFFECTIVE: ~~April 11, 2012~~

GULF POWER
A SOUTHERN COMPANY

Section No. VI
~~Fourth~~Fifth Revised Sheet No. 6.54
Canceling ~~Third~~Fourth Revised Sheet No. 6.54

[redacted]

(Continued from Rate Schedule PXT, Sheet No. 6.53)

DETERMINATION OF THE ON-PEAK PERIOD:

The on-peak period for calendar months April through October is defined as being those hours between 12:00 p.m. and 9:00 p.m. Central Daylight Time/Central Standard Time, Monday through Friday.

The on-peak period for calendar months November through March is defined as being those hours between 6:00 a.m. and 10:00 a.m. and between 6:00 p.m. and 10:00 p.m. Central Standard Time/Central Daylight Time, Monday through Friday.

DETERMINATION OF THE OFF-PEAK PERIOD:

All hours not included above and all hours of the observed holidays of New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving, and Christmas are in the off-peak period.

MINIMUM MONTHLY BILLS:

In the event the Customer's annual load factor for the current and preceding eleven months is less than 75% and in consideration of the readiness of the Company to furnish such service, the minimum monthly bill shall not be less than the Base Charge plus ~~$11.43~~13.15 per kW of maximum billing demand.

DETERMINATION OF BILLING DEMAND:

(a) Maximum Demand--The kilowatt (kW) billing demand for billing purposes shall be the maximum measured kw demand integrated over any fifteen minute interval during the current bill month but not less than 7500 kW.

(b) On-Peak Demand--The kilowatt (kW) billing demand for billing purposes shall be the customer's maximum integrated 15 minute demand to the nearest kilowatt (kW) during each service month as measured during the hours designated as on-peak.

REACTIVE DEMAND CHARGE:

The monthly bill calculated at the above rates shall also be increased in the amount of $1.00 per kvar for all over 0.48432 kilovars per kilowatt (90% power factor). The kilovars to which this adjustment shall apply shall be the monthly maximum measured kilovar demand or may be calculated as the square root of the difference between the square of the maximum monthly measured kVA demand and the square of the maximum monthly measured kW demand.

ISSUED BY: S. W. Connally, Jr.

GULF POWER
A SOUTHERN COMPANY

Section No. VI
~~Fourth~~Fifth Revised Sheet No. 6.59
Canceling ~~Third~~Fourth Revised Sheet No. 6.59

[redacted]

(Continued from Rate Schedule SBS, Sheet No. 6.58)

A Standby Service Customer will be billed for electric service in accordance with the following charges:

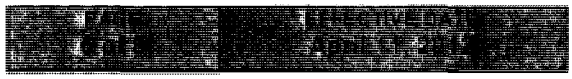
Contract Demand:	100 to 499 kW	500 to 7,499 kW	Above 7,499 kW
Base Charge:	$248.20	$248.20	$591.01
Demand Charge:			
Local Facilities Charge Per kW of BC and NC	$2.66	$2.35	~~$0.81~~1.04
On-Peak Demand Charge: Per kW of On-Peak kW up to NC	~~$3.18~~3.66	~~$8.04~~9.84	~~$8.76~~10.07
Plus the greater of:			
Reservation Charge: Per kW of BC or	~~$0.95~~1.18	~~$0.95~~1.18	~~$0.98~~1.21
The Sum of the Daily On-Peak Standby Demand Charges: Per kW per day of On-Peak kW in excess of NC	~~$0.45~~0.56	~~$0.45~~0.56	~~$0.47~~0.57
Energy Charge Per kWh:	~~1.930~~3.460¢	~~1.055~~3.460¢	~~1.022~~3.460¢

Customers with zero (0) NC will not be subject to the On-Peak Demand Charge.

ISSUED BY: S. W. Connally, Jr

GULF POWER
A SOUTHERN COMPANY

Section No. VI
~~Second~~Third Revised Sheet No. ~~6~~.62
Canceling ~~First~~Second Revised Sheet No. 6.62



(Continued from Rate Schedule SBS, Sheet No. 6.61)

TRANSFORMER OWNERSHIP DISCOUNT AND PRIMARY METERING VOLTAGE DISCOUNTS:

When the Company renders service under this Rate Schedule at the local primary distribution voltage and any transformers required are furnished by the Customer, the monthly rate will be subject to a discount of: ~~seven~~six (~~7~~6) cents per month per kilowatt (kW) of the Customer's demand used in the calculation of the Local Facilities Charge for those customers which are billed under the 100 to 499 kW demand range; or ~~seven~~six (~~7~~6) cents per month per kilowatt (kW) of the Customer's demand used in the calculation of the Local Facilities Charge for those customers which are billed under the 500 to 7,499 kW demand range; and an additional discount of one percent (1%) of the Energy Charge and one percent (1%) of the Demand Charge.

TRANSFORMER OWNERSHIP DISCOUNT AND TRANSMISSION METERING VOLTAGE DISCOUNTS:

When the Company renders service under this Rate Schedule from an available transmission line of 46,000 volts or higher and the Customer furnishes, operates, and maintains the complete step-down transformer substation necessary to receive and use such service, the monthly rate will be subject to a discount of ~~nine~~seven (~~9~~7) cents per month per kilowatt (kW) of the Customer's demand used in the calculation of the Local Facilities Charge for those customers which are billed under the 500 to 7,499 kW demand range and an additional discount of two percent (2%) of the Energy Charge and two percent (2%) of the Demand Charge. The monthly rate will be subject to a discount of ~~seven~~six (~~7~~6) cents per kilowatt (kW) of the demand used in the calculation of the Local Facilities Charge for those customers which are billed under the above 7,499 kW demand range and an additional discount of one percent (1%) of the Energy Charge and one percent (1%) of the Demand Charge.

TERM OF CONTRACT:

Service under this rate schedule shall be for a minimum period of five (5) years and shall continue thereafter from year to year until terminated by either party upon twenty-four (24) months written notice to the other.

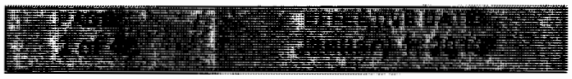
DEPOSIT:

A deposit amounting to twice the estimated average monthly bill may be required before service is connected at designated premises. The deposit may be applied to any final bills against the Customer for service.

ISSUED BY: ~~Mark Crosswhite~~S. W. Connally, Jr.

GULF POWER
A SOUTHERN COMPANY

Section No. VI
~~Fifth~~Sixth Revised Sheet No. 6.76
Canceling ~~Fourth~~Fifth Revised Sheet No. 6.76



(Continued from Rate Schedule RSVP, Sheet No. 6.75)

If a Customer moves into a residence with existing Company-owned energy management equipment, the Customer will receive service under Rate Schedule RSVP. The Customer will be given the option of remaining on Rate Schedule RSVP or moving to Rate Schedule RS. If the Customer chooses Rate Schedule RS at that time, Company-owned energy management equipment will be removed free of charge.

CHARACTER OF SERVICE:

Available for single-phase service from local distribution lines of the Company's system at nominal secondary voltage of 120/240 volts. Service shall be metered through one metering device capable of measuring electrical energy consumption during the various times each energy demand charge is in effect.

~~MONTHLY~~ RATES:

Base Charge:	~~$15.00~~0.60 per day
Energy Demand Charge:	
Low Cost Hours (P_1):	~~4.313~~4.884¢ per kWh
Medium Cost Hours (P_2):	~~4.313~~4.884¢ per kWh
High Cost Hours (P_3):	~~4.313~~4.884¢ per kWh
Critical Cost Hours (P_4):	~~4.313~~4.884¢ per kWh

ISSUED BY: S. W. Connally, Jr.

GULF POWER
A SOUTHERN COMPANY

Section No. VI
Original Sheet No. 6.92

[redacted]

Rate Rider LBIR
Experimental Rate Rider
Large Business Incentive Rider
(Optional Rider)

AVAILABILITY:

This Rate Rider is available to all Customers within Gulf Power's service area who meet qualifying load and employment requirements.

The qualifying load and employment requirements under this Rider must be achieved at the same delivery point. Additional metering equipment may be required for service under this Rider.

APPLICABILITY:

Applicable to New Load as a Rate Rider to the rates specified below. All terms and conditions of the rate under which the Customer takes service remain applicable, except that the Customer's billing will be credited by the incentive specified below beginning with the commencement of service pursuant to this Rider. New Load is that which is added via connection of initial service after the effective date of this Rider but not later than December 31, 2015. This Rider does not apply to provision of electric service through existing delivery points.

Rate Rider LBIR shall only be combined with Rate Schedules LP, LPT, PX, PXT or RTP. If a change in ownership occurs during the Term of Service under this Rider, the successor Customer may be allowed to fulfill the balance of the Contract under this Rider.

ISSUED BY: S. W. Connally, Jr.

GULF POWER
A SOUTHERN COMPANY

Section No. VI
Original Sheet No. 6.93

(Continued from Rate Rider LBIR, Sheet No. 6.92)

INCENTIVES:

Subject to compliance with the terms and conditions hereof, the following credits will be applied to the base demand charges and base energy charges of the Customer's applicable rate schedule:

- Year 1 – 60% reduction in base demand and base energy charges
- Year 2 – 45% reduction in base demand and base energy charges
- Year 3 – 30% reduction in base demand and base energy charges
- Year 4 – 15% reduction in base demand and base energy charges
- Year 5 – 0% reduction in base demand and base energy charges

Qualifying Loads:

(1) Qualifying load must be at least 1,000 kW, as determined by the Company.
(2) The Customer must provide audit documentation by the Florida Department of Economic Opportunity proving the hiring of 25 full-time employees per 1,000 kW of qualifying load.
(3) The Customer must demonstrate new capital investment of at least $1,000,000.
(4) The Customer must provide an affidavit verifying that the availability of the Rider is a significant factor in the Customer's decision to request service from Gulf Power Company.

TERM:

Service under this Rate Rider requires a Contract for Electric Service that includes a minimum five-year term. Service under this Rider will terminate at the end of the contract term.

During the term of service under this Rate Rider, the Customer may elect to change to an applicable rate to which Rate Rider LBIR does not apply so long as the Customer commits to take service under the newly selected rate for the unexpired duration of the term of the original Contract for Electric Service.The Company may terminate service under this Rider at any time if the Customer fails to comply with the terms and conditions of this Rider. Failure to: (1) maintain that level of employment specified in this Rider and/or (2) purchase from the Company the amount of load specified in this Rider may be considered grounds for termination.

Service under this Rider is subject to the Rules and Regulations of the Company and the Florida Public Service Commission.

ISSUED BY: S. W. Connally, Jr.

GULF POWER
A SOUTHERN COMPANY

Section No. VI
Original Sheet No. 6.94

Rate Rider SBIR
Experimental Rate Rider
Small Business Incentive Rider
(Optional Rider)

AVAILABILITY:

This Rate Rider is available to all Customers within Gulf Power's service area who meet qualifying load and employment requirements.

The qualifying load and employment requirements under this Rider must be achieved at the same delivery point. Additional metering equipment may be required for service under this Rider.

APPLICABILITY:

Applicable to New Load as a Rate Rider to the rates specified below. All terms and conditions of the rate under which the Customer takes service remain applicable, except that the Customer's billing will be credited by the incentive specified below beginning with the commencement of service pursuant to this Rider. New Load is that which is added via connection of initial service after the effective date of this Rider but not later than December 31, 2015. This Rider does not apply to provision of electric service through existing delivery points.

Rate Rider SBIR shall only be combined with Rate Schedules GSD, GSDT, GSTOU, LP, LPT, PX, PXT or RTP. If a change in ownership occurs during the Term of Service under this Rider, the successor Customer may be allowed to fulfill the balance of the Contract under this Rider.

ISSUED BY: S. W. Connally, Jr.

GULF POWER
A SOUTHERN COMPANY

Section No. VI
Original Sheet No. 6.95

[redacted]

(Continued from Rate Rider SBIR, Sheet No. 6.94)

INCENTIVES:

Subject to compliance with the terms and conditions hereof, the following credits will be applied to the base demand charges and base energy charges of the Customer's applicable rate schedule:

- Year 1 – 20% reduction in base demand and base energy charges
- Year 2 – 15% reduction in base demand and base energy charges
- Year 3 – 10% reduction in base demand and base energy charges
- Year 4 – 5% reduction in base demand and base energy charges
- Year 5 – 0% reduction in base demand and base energy charges

Qualifying Loads:

(1) Qualifying load must be at least 200 kW, as determined by the Company.
(2) The Customer must provide audit documentation by the Florida Department of Economic Opportunity proving the hiring of 10 full-time employees.
(3) The Customer must provide an affidavit verifying that the availability of the Rider is a significant factor in the Customer's decision to request service from Gulf Power Company.

TERM:

Service under this Rate Rider requires a Contract for Electric Service that includes a minimum five-year term. Service under this Rider will terminate at the end of the contract term.

During the term of service under this Rate Rider, the Customer may elect to change to an applicable rate to which Rate Rider SBIR does not apply so long as the Customer commits to take service under the newly selected rate for the unexpired duration of the term of the original Contract for Electric Service. The Company may terminate service under this Rider at any time if the Customer fails to comply with the terms and conditions of this Rider. Failure to: (1) maintain that level of employment specified in this Rider and/or (2) purchase from the Company the amount of load specified in this Rider may be considered grounds for termination.

Service under this Rider is subject to the Rules and Regulations of the Company and the Florida Public Service Commission.

ISSUED BY: S. W. Connally, Jr.

Section VII
~~First~~Second Revised Sheet No. 7.11
Canceling ~~Original~~First Revised Sheet No. 7.11

~~GULF POWER COMPANY~~

~~CONTRACT FOR SEASONAL ELECTRIC POWER~~
~~Form 3~~

~~Rate Schedule _____~~

~~MEMORANDUM OF AGREEMENT made this _____ day of _____, 19_____, by and between Gulf Power Company, a corporation, hereafter for brevity and convenience called the Company; and _____, hereafter called the Customer.~~

~~WITNESSETH:~~

~~In consideration of the mutual promises and agreements of the parties, each to the other, hereinafter contained, they agree and bind themselves as follows:~~

~~1. That this agreement is supplemental to, and when executed and approved shall become a part of and be construed in connection with and as a modification of, that certain contract for electric service executed by and between the parties hereto bearing date the _____ day of _____, 19_____, attached hereto, and hereby referred to as fully and with the same effect as of its terms were set out herein.~~

~~2. In and by this supplemental agreement the terms and conditions of such contract for electric service, hereinabove referred to, are hereby modified for a minimum period of _____ years, in the following particulars, to wit:~~

~~(a) DEMAND CHARGE:~~

~~The monthly demand charge specified in such original contract for electric service hereinabove referred to shall be increased by the amount per kilowatt specified in item 1 of Rate Schedule SR or at such lawful rate as may supersede same only during the months seasonal service is furnished.~~

~~(b) DETERMINATION OF DEMAND:~~

~~The terms of the determination of the demand in the original contract for electric service hereinabove referred to are suspended during the period of the applicability of this memorandum of agreement to the extent that the kilowatt demand shall be based, while this memorandum of agreement is applicable and in force on the Customer's maximum integrated fifteen minute demand during each service month.~~

~~(c) MINIMUM BILL:~~

~~In consideration of the readiness to furnish the seasonal service herein stipulated for and the Customer's purchase of such service upon the conditions herein expressed, the Company shall, and hereby does, suspend, during the period of the applicability of this memorandum of agreement, the minimum monthly bill stipulated for in the original contract for electric service hereinabove referred to, on the express condition that the Customer shall and hereby agrees to pay to the Company,~~**Reserved for Future Use**

ISSUED BY: S. W. Connally, Jr. Effective:

Section VII
~~First~~Second Revised Sheet No. 7.12
Canceling ~~Original~~First Revised Sheet No. 7.12

~~(c) MINIMUM BILL (Continued)~~

~~annually, while this memorandum of agreement is applicable and in force, at least the minimum charge specified in item 2 of Rate Schedule SR, or its lawful successors. This agreement on the part of the Customer shall constitute a guarantee by the Customer to the Company of a minimum annual revenue as determined by the provisions of Rate Schedule SR or its lawful successors, in the event that the current delivered to and used by the Customer during each year that this memorandum of agreement is applicable and in force should at the rate herein amount to less than such minimum annual guarantee. And at the end of each twelve month period, if the current delivered to and used by the Customer during each year that this memorandum of agreement is applicable and in force should at the rate herein amount to less than such minimum annual guarantee, the Customer agrees to pay such difference to the Company immediately upon demand.~~

~~3. This agreement shall not be binding upon the Company until it has been approved in writing endorsed hereon by an officer of the Company, after having been duly signed by the Customer. All previous communications between the parties hereto, whether oral or written, with reference to the subject matter of this agreement, are hereby abrogated and merged into this agreement, and no modification hereof shall be binding unless it shall be in writing, duly accepted by the Customer and approved by an officer of the Company. This agreement shall not be assigned by the Customer without the written consent of the Company.~~

~~Attest: GULF POWER COMPANY~~

~~Secretary By Vice President~~

~~WITNESS AS TO CUSTOMER:~~

~~By~~
~~Customer~~

~~By~~
~~Official Capacity~~

~~Form 3~~**Reserved for Future Use**

ISSUED BY: S. W. Connally, Jr. Effective:

Section VII
~~Sixth~~Seventh Revised Sheet No. 7.13
Canceling ~~Fifth~~Sixth Revised Sheet No. 7.13

GULF POWER COMPANY
OUTDOOR SERVICE - LIGHTING PRICING METHODOLOGY
MONTHLY RATES - Rate Schedule OS (Part I/II)
Form 4

SECTION A - LED FIXTURES

Total Unit Cost		
Fixture Cost		$0.00
Arm Cost		$0.00
Bulb Cost		$0.00
Photocell Cost		$0.00
	SUBTOTAL	$0.00
0.000 Man-hours to Install Fixture/Arm (If Applicable) @ $~~52.70~~53.28/Manhour		$0.00
	SUBTOTAL	$0.00
~~30~~36.0% Engineering & Supervision Overheads		$0.00
	UNIT COST TOTAL	$0.00
Fixture Charge		
Fixed Charge = (15.235% x Unit Cost Total)/12 Months		$0.00
Revenue Tax = Fixed Charge x 0.000721		$0.00
	FIXTURE CHARGE	**$0.00**
Maintenance Charge		
Average Annual Bulb Failure Rate : 0.0%		
Bulb Life (in hours) Failure Rate = (Ann. Burn Hrs / Bulb Life)		
Annual Burn hours		
~~Spot Rebulb Cost = (Bulb Cost + Photocell Cost + $29 Labor) x Bulb Failure Rate/12 Months~~		~~$0.00~~
~~Starter~~Photocell Replacement = (~~Starter~~Photocell Cost + Labor) x ~~Starter~~Photocell Failure Rate/12 Months		$0.00
~~Starter~~Photocell Life (in hours Failure Rate = (Ann. Burn Hrs / ~~Starter~~Photocell Life)		
$ ~~Starter~~Photocell Cost = 0		
~~Starter~~Photocell Replacement Labor Hrs		
~~Ballast~~Driver Replacement = (~~Ballast~~Driver Cost + Labor) x ~~Ballast~~Driver Failure Rate/12 Months		$0.00
~~Ballast~~Driver Life (in hours) Failure Rate = (Ann. Burn Hrs / ~~Ballast~~Driver Life)		
$ ~~Ballast~~Driver Cost = 0		
~~Ballast~~Driver Replacement Labor Hrs		
Surge Protection Device (SPD) Replacement = (SPD Cost + Labor) x SPD Failure Rate/12 Months		$0.00
SPD Life (in hours) Failure Rate = (Ann. Burn Hrs / SPD Life)		
$ SPD Cost = 0		
SPD Replacement Labor Hrs		
Luminaire Repair Cost =		
[Man-hours to Remove of 0.36 @ $ ~~52.70~~53.28/Manhour + Unit Cost Total]		
x 6.7% Annual Luminaire Failure Rate/12 Months		$0.00
	SUBTOTAL	$0.00
Revenue Tax = Subtotal x 0.000721		$0.00
	MAINTENANCE CHARGE	**$0.00**
Energy Charge		
0 Line Wattage x 4,120 Annual Operating Hours/(1,000 x 12) =		
0 kWh @ $~~0.02316~~0.02448/kWh	**ENERGY CHARGE**	**$0.00**

PRICE SUMMARY	
Fixture Charge	**$0.00**
Maintenance Charge	**$0.00**
Energy Charge	**$0.00**
TOTAL MONTHLY CHARGE PER FIXTURE	**$0.00**

ISSUED BY: S. W. Connally, Jr.

EFFECTIVE: ~~January 1, 2013~~

Section VII
Original Sheet No. 7.13.1

Form 4 (Continued)

SECTION A-1 - Non-LED FIXTURES

Total Unit Cost	
Fixture Cost	$0.00
Arm Cost	$0.00
Bulb Cost	$0.00
Photocell Cost	$0.00
SUBTOTAL	$0.00
0.000 Man-hours to Install Fixture/Arm (If Applicable) @ $53.28/Manhour	$0.00
SUBTOTAL	$0.00
36.0% Engineering & Supervision Overheads	$0.00
UNIT COST TOTAL	$0.00
Fixture Charge	
Fixed Charge = (15.235% x Unit Cost Total)/12 Months	$0.00
Revenue Tax = Fixed Charge x 0.000721	$0.00
FIXTURE CHARGE	**$0.00**
Maintenance Charge	
Average Annual Bulb Failure Rate : 0.0%	
Bulb Life (in hours) Failure Rate = (Ann. Burn Hrs / Bulb Life)	
Annual Burn hours	
Spot Rebulb Cost = (Bulb Cost + Photocell Cost + $29 Labor) x Bulb Failure Rate/12 Months	$0.00
Luminaire Repair Cost = [Man-hours to Remove of 0.36 @ $53.28/Manhour + Unit Cost Total] x 6.7% Annual Luminaire Failure Rate/12 Months	$0.00
SUBTOTAL	$0.00
Revenue Tax = Subtotal x 0.000721	$0.00
MAINTENANCE CHARGE	**$0.00**
Energy Charge	
Line Wattage x 4,120 Annual Operating Hours/(1,000 x 12) = 0 kWh @ $0.02448/kWh **ENERGY CHARGE**	**$0.00**

PRICE SUMMARY	
Fixture Charge	**$0.00**
Maintenance Charge	**$0.00**
Energy Charge	**$0.00**
TOTAL MONTHLY CHARGE PER FIXTURE	**$0.00**

ISSUED BY: S. W. Connally, Jr.

EFFECTIVE:

Section VII
~~Sixth~~Seventh Revised Sheet No. 7.15
Canceling ~~Fifth~~Sixth Revised Sheet No. 7.15

Form 4 (Continued)

SECTION C - RELAMPING SERVICE AGREEMENT

Bulb and Photocell Cost	
Bulb Cost	$0.00
Photocell Cost	$0.00
BULB AND PHOTOCELL COST	$0.00
Relamping Charge	
Average Annual Bulb Failure Rate : 0.0%	
Bulb Life (in hours) Failure Rate = (Ann. Burn Hrs / Bulb Life)	
Annual Burn hours	
Spot Rebulb Cost =(Bulb Cost + Photocell Cost + $29 Labor) x Bulb Failure Rate/12 Months	$0.00
SUBTOTAL	$0.00
Revenue Tax = Subtotal x 0.000721	$0.00
~~RELAMPING CHARGE~~	~~$0.00~~
RELAMPING CHARGE	**$0.00**
Energy Charge	
0 Line Wattage x 4,120 Annual Operating Hours/(1,000 x 12) =	
0 kWh @ ~~$0.023160~~0.02448/kWh **ENERGY CHARGE**	**$0.00**

PRICE SUMMARY	
Relamping Charge	**$0.00**
Energy Charge	**$0.00**
TOTAL MONTHLY CHARGE PER FIXTURE	**$0.00**

ISSUED BY: S. W. Connally, Jr.

EFFECTIVE: ~~January 1, 2013~~

Section VII
~~Seventeenth~~Eighteenth Revised Sheet No. 7.16
Canceling ~~Sixteenth~~Seventeenth Revised Sheet No. 7.16

GULF POWER COMPANY
CONTRACT FOR STREET AND
GENERAL AREA LIGHTING SERVICE
RATE SCHEDULE OS (PART I/II)

Form 5

Contract No. _____

Customer Name _____ Date _____

DBA _____ Telephone No. _____ Tax I. D. (if applicable) _____

Street Address (Subdivision, etc.) of Light(s) _____

Billing Address _____

Driving Directions _____

_____

Location of Light(s) _____

Meter No. _____ Account No. _____ JETS WO No. _____

The Applicant requests Gulf Power Company to furnish the facilities described on Sheet No. 7.16.1 and the necessary electric energy for the operation thereof and hereby agrees to take and pay for the same in accordance with and subject to the Company's Rate Schedule "OS (PART I/II)" and Rules and Regulations for Electric Service on file in its office and on file with the Florida Public Service Commission or any changes therein as approved by the Florida Public Service Commission. In consideration of the supplying and maintenance of said electric current and facilities the Applicant hereby grants to Gulf Power Company, the right to construct, operate, and maintain upon, over, under, and across the premises located at the above service address its poles, lines, facilities, and appliances necessary in connection therewith for the transmission of electric power together with the rights of ingress and egress to and from said lines and the right to cut and keep clear all trees and other obstructions that may injure or endanger said lines. All fixtures, equipment and material used in the construction, operation, and maintenance of said facilities shall remain at all times the property of Gulf Power Company. The contract term as provided by Rate Schedule "OS (PART I/II)" shall be for an initial period of ~~five (5) years for high pressure sodium street lighting, three (3) years if any high pressure sodium vapor (non-residential) or metal halide (non-residential) general area lighting is installed, and two (2) years if any high pressure sodium vapor (residential) general area lighting is installed, unless a~~not less than three (3) years. Additional facilities required ~~by the Company require~~for the installation may constitute a longer term. At the time Gulf Power Company begins to install any facilities applied for herein, this application becomes a contract for a term of _____ years and thereafter from year to year until terminated by ~~three (3) months' written notice by~~notice to either party ~~to~~by the other. Any damage done by vandalism shall be handled in accordance with the provisions of Rate Schedule "OS (Part I/II)". The location of said facilities shall be as specified by the Applicant and the Company shall be held harmless in connection therewith or the use thereof. Should the Applicant discontinue this service before the expiration of the full term of contract all unpaid charges for the full term shall immediately become due and payable. In the event the supply of electric current should be interrupted or fail by reason of accident, or condition beyond the control of Gulf Power Company, the service shall be restored within a reasonable time and such interruption shall not constitute a breach of the contract, nor shall Gulf Power Company be liable for damages by reason of such interruption or failure. For street lights, lamps are located on MAP which is hereto appended and made a part hereof.

GULF POWER COMPANY	CUSTOMER
Application Taken By _____	Customer _____
Approved by _____ Authorized Company Representative	Title _____
Signature _____	Signature _____
Date _____	Date _____

ISSUED BY: ~~Mark Crosswhite~~S. W. Connally, Jr. EFFECTIVE: ~~April 11, 2012~~

Section No. VII
~~Fifth~~Sixth Revised Sheet No. 7.24
Canceling ~~Fourth~~Fifth Revised Sheet No. 7.24

GULF POWER COMPANY

AGREEMENT FOR UNDERGROUND ELECTRIC CONSTRUCTION BY THE UTILITY
Form 8

THIS AGREEMENT made and entered into this _____ day of _____, 20____, by and between GULF POWER COMPANY, hereinafter called the Utility, and _____, hereinafter called the Applicant, sets forth the standards and conditions which will apply to the construction, installation, repair and ownership of the underground facilities to be located at _____, Exhibit "A" hereto, contains a detailed description of the property where the facilities will be constructed or installed.

WITNESSETH THAT:

WHEREAS, the Utility owns and operates an electric distribution system in _____ County, Florida, in which the Applicant owns the real property described in Exhibit "A" on some or all of which the Applicant has constructed or proposes to construct certain improvements; and

WHEREAS, the Applicant has requested the Utility to supply and install all primary, secondary, and service trench, duct, and cable for the purpose of supplying electric service to the improvements to be located on the property described on Exhibit "A"; and

WHEREAS, the Utility desires to cooperate with the Applicant and to install the underground distribution system;

NOW, THEREFORE, in consideration of the premises and of the mutual agreements hereinafter set forth, it is agreed by and between the parties as follows:

1. Upon compliance by Applicant with all of the provisions of this Agreement in a manner acceptable to the Utility, the Utility shall install, own and maintain the necessary facilities for providing underground electric service to the improvements located on that portion of the property as shown on Exhibit "C" (construction drawing) attached. At no time shall the Utility be required by the Applicant, its successors or assigns to furnish other than single phase service through these facilities except as otherwise shown on Exhibit "C" and at a cost to the Applicant as specifically described in Exhibit "C".

2. The Applicant agrees to prepare an orderly plan for the location of all utility lines and equipment to be installed and to cause all utility companies and contractors involved to install their lines and equipment in the locations specified in said plan.

3. The Applicant agrees to cause to be conveyed to the Utility, without cost, all easements, including rights of ingress and egress, necessary or convenient to the Utility or required by it for the purpose of constructing, operating, maintaining, and removing said underground electrical distribution lines and other necessary equipment.

4. The Applicant shall remove or cause to be removed, at his expense, from the Utility easement or route of trench line, whether in a street, alley or otherwise, all trees, stumps or any other obstructions and shall not hard surface street, parking areas, court , walkways, or other areas on the trench line route until the necessary ducts have been installed by the Utility. The Applicant shall locate and mark all property and/or lot corners and establish finish grade along the route of construction of the underground distribution system. The Applicant agrees to reimburse the Utility for the costs of facilities found to be installed at the wrong location or grade due to Applicant requested changes in property lines, easement, grade, and/or errors in staking or trenching.

5. The service entrance facilities for the improvements shall in all respects conform to the requirements of all applicable codes, the Rules and Regulations of the Utility, and the terms of this Agreement. The Applicant and his successors in interest will provide the service entrance facilities in accordance with Exhibit "B" (appropriate distribution standard specification).

NOW, THEREFORE, in consideration of the premises and of the mutual agreements hereinafter set forth, it is agreed by and between the parties as follows:

1. The Utility hereby agrees to permit the Applicant to construct and install all or a portion of the underground distribution facilities described herein below at the above location provided:

a) such work meets the Utility's construction standards, as set forth below:

(1) Conduit to be placed in any Utility underground distribution system must meet the specifications set forth in Exhibit "D" (appropriate distribution standard specification). Conduit shall be installed in the locations specified in Exhibit "C" (construction drawing);

(2) Primary and secondary conduit must be buried with 30" of cover or at a depth that meets applicable codes and is satisfactory to the utility and the applicant;

(3) The connection between the meter enclosure and the underground service entrance shall be in accordance with Exhibit "B" (appropriate distribution standard specification);

(4) Where the applicant installs the conduit, the applicant must install a tracer wire in the trench with the conduit as specified in Exhibit "E";

(5) When the Utility supplies the conduit to the Applicant, the Utility shall take ownership of that conduit at the time it is installed by the Applicant and all other provisions of this agreement have been satisfied. When the Applicant supplies and installs the conduit, the Utility shall take ownership of that conduit at the time the cable has been installed in the conduit by the Utility and all other provisions of this agreement have been satisfied. Until such time that the Utility takes ownership of the conduit, the Applicant, or Contractor acting for the Applicant, shall be responsible for accessing and repairing the conduit;

(6) After which time the Utility takes ownership of the conduit, the Utility shall be responsible for accessing, in a reasonable manner, and repairing the conduit and cable. The Applicant's

ISSUED BY: ~~Susan Story~~S. W. Connally, Jr. ~~2004~~ **EFFECTIVE:** ~~June 29,~~

aforementioned duty includes, but is not limited to, repairs necessitated by the Utility accessing and repairing conduit or cable and specifically includes all repairs made necessary as a result of placement of conduit beneath a roadway. The Applicant will have no right, title or interest in or to the completed distribution facilities;

(7) The Utility reserves the right to verify, prior to taking ownership of the conduit system, that the duct system is installed as specified in the plan provided by the Utility under section 4, below. The Utility may exercise, at any time, its right to inspect and verify any Applicant provided facility, and any such inspection or verification shall not be deemed an approval of any Applicant provided facility or a waiver by the Utility of any right to enforce strict compliance with the terms and conditions of this agreement;

(b) that in the Utility's sole discretion such Agreement is not expected to cause the general body of ratepayers to incur greater costs;

(c) the Applicant agrees to pay ~~to the Utility the prevailing hourly rate for~~Gulf Power Company's current applicable ~~e~~Engineering ~~personnel for time spent reviewing and inspecting the Applicant's work when such time is beyond that normally required of the Utility's engineering personnel to review and inspect underground construction of the type installed or constructed by the Applicant~~and Supervision rate associated with the estimate of work to be performed by the Applicant. This amount represents the cost of Gulf's engineering time to review and inspect the Applicant's work.

(d) the Applicant agrees to correct, to the satisfaction of the Utility, any deficiencies found by the Utility prior to the connection of any customers to the underground electric distribution system or the connection of the underground electric distribution facilities to Utility's distribution system. Deficiencies must be corrected in a timely manner or the Utility shall construct the system improvement using overhead facilities and the Applicant will have to pay the cost of such improvement and the cost of its removal before the corrected underground facilities will be connected;

2. Upon compliance by Applicant with all of the provisions of this Agreement in a manner acceptable to the Utility, the Utility shall own and maintain the necessary facilities for providing underground electric service to the property as shown on Exhibit "C" hereto. At no time shall the Utility be required by the Applicant, its successors or assigns to furnish other than single phase service through these facilities, except as otherwise shown on Exhibit "C". Three-phase service will be furnished only when specified on Exhibit "C" and paid for in advance by the Applicant. The Applicant agrees to reimburse the Utility for the costs of facilities found to be installed at the wrong location or grade due to Applicant requested changes in property lines, easement, grade, and/or errors in staking or trenching.

ISSUED BY: ~~Travis Bowden~~S. W. Connally, Jr.
~~June 24, 1997~~

EFFECTIVE:

Section VII
~~Original~~First Revised Sheet No. 7.43
Canceling Original Sheet No. 7.43

APPLICATION FOR UNDERGROUND COST ESTIMATE
(Form 17)

Name _____

Address _____

Phone _____

Type estimate requested _____ Non-binding _____ Binding

Location / description of requested project _____

_____

_____

_____

_____

_____

_____

This application and the deposit paid is for the purpose of obtaining a estimate of the cost of underground facilities pursuant to Section IV Part VI of Gulf Power Company's Tariff for Retail Service, Sheets ~~6~~4.21 through ~~6~~4.28.1. Said provisions govern this application as if fully set forth herein.

Signed _____ Amount paid $ _____
(Binding cost estimate only)
(To be calculated by Gulf Power in accordance with Tariff Section IV, Subpart 6.4~~5~~.3)

FOR COMPANY USE ONLY

Length in miles of underground trench or overhead primary to be converted _____

Amount of deposit $_____

Received by _____

Date Received by Gulf Power Company _____

Notice: The deposit paid applies specifically to the scope of work defined above. It cannot be credited to charges for any other work due to revisions in the scope.

ISSUED BY: ~~D. L. McCrary~~S. W. Connally, Jr. **EFFECTIVE:** ~~May 10, 1993~~

Section VII
~~Seventh~~Eighth Revised Sheet No. 7.45
Canceling ~~Sixth~~Seventh Revised Sheet No. 7.45

GULF POWER COMPANY
OPTIONAL RELAMPING SERVICE AGREEMENT
CUSTOMER-OWNED STREET AND GENERAL AREA LIGHTING
RATE SCHEDULE OS (PART I/II)
Form 19

Contract No. _____

Customer Name _____ Date _____

DBA _____ Telephone No. _____ Tax I. D.. _____

Street Address (Subdivision, etc.) of Light(s) _____

Mailing Address _____

Driving Directions _____

_____

Location of Light(s) _____
Meter No. _____ Account No. _____ JETS WO No.
_____

UNMETERED CUSTOMER-OWNED FIXTURES:
High Pressure Sodium Vapor Lighting:

_____ 8,800 Lumen (100 Watts) Light(s) to be billed at a base rate of $~~1.59~~1.68 each per month	$ _____
_____ 16,000 Lumen (150 Watts) Light(s) to be billed at a base rate of $~~2.21~~2.33 each per month	$ _____
_____ 20,000 Lumen (200 Watts) Light(s) to be billed at a base rate of $~~2.51~~2.65 each per month	$ _____
_____ 25,000 Lumen (250 Watts) Light(s) to be billed at a base rate of $~~2.97~~3.15 each per month	$ _____
_____ 46,000 Lumen (400 Watts) Light(s) to be billed at a base rate of $~~4.44~~4.70 each per month	$ _____
_____ 125,000 Lumen (1000 Watts) Light(s) to be billed at a base rate of $~~9.61~~10.16 each per month	$ _____

Metal Halide Lighting:

_____ 32,000 Lumen (400 Watts) Light(s) to be billed at a base rate of $~~4.55~~4.81 each per month	$ _____

METERED CUSTOMER-OWNED FIXTURES:
High Pressure Sodium Vapor Lighting:

_____ 8,800 Lumen (100 Watts) Light(s) to be billed at a base rate or $~~0.64~~0.68 each per month	$ _____
_____ 16,000 Lumen (150 Watts) Light(s) to be billed at a base rate of $~~0.63~~0.67 each per month	$ _____
_____ 20,000 Lumen (200 Watts) Light(s) to be billed at a base rate of $~~0.65~~0.69 each per month	$ _____
_____ 25,000 Lumen (250 Watts) Light(s) to be billed at a base rate or $~~0.66~~0.70 each per month	$ _____
_____ 46,000 Lumen (400 Watts) Light(s) to be billed at a base rate or $~~0.65~~0.69 each per month	$ _____
_____ 125,000 Lumen (1000 Watts) Light(s) to be billed at a base rate of $~~0.83~~0.88 each per month	$ _____

Metal Halide Lighting:

_____ 32,000 Lumen (400 Watts) Light(s) to be billed at a base rate or $~~0.78~~0.82 each per month	$ _____
Total Base Monthly Charge*	$ _____

*Base monthly charge does not include Fuel Charge, Purchased Power Capacity Charge, Environmental Charge, Energy Conservation Charge, Natural Disaster Recovery Surcharge, applicable taxes, or fees.

The Applicant requests a relamping service agreement on the lamp(s) and photocell(s) for the fixtures described above and the necessary electric energy (if unmetered) for the operation thereof and hereby agrees to take and pay for the same in accordance with and subject to the Company's Rate Schedule "OS (PART I/II)" and Rules and Regulations for Electric Service on file in its office and on file with the Florida Public Service Commission or any changes therein as approved by the Florida Public Service Commission. This agreement and the monthly rates set forth above cover both the electric service (if unmetered) and the replacement of lamps and photoelectric controls upon routine failure. Lamps or photoelectric controls damaged or destroyed due to vandalism or willful abuse are not covered by this agreement and will only be replaced at the Applicant's expense. The Applicant remains responsible for all maintenance other than the replacement of lamps and photoelectric controls. The distribution system shall serve no other electrical loads except the lighting equipment described above.

ISSUED BY: S. W. Connally, Jr. EFFECTIVE: ~~January 1, 2013~~

Section VII
~~Sixth~~Seventh Revised Sheet No. 7.55
Canceling ~~Fifth~~Sixth Revised Sheet No. 7.55

GULF POWER COMPANY
CUSTOMER-OWNED LIGHTING AGREEMENT
(WITHOUT RELAMPING SERVICE PROVISIONS)
RATE SCHEDULE OS (PART I/II)

Form 24

Contract No. _____

Customer Name _____ Date _____

DBA _____ Telephone No. _____ Tax I. D. _____

Street Address (Subdivision, etc.) of Light(s) _____

Billing Address _____

Driving Directions _____

No. of Light(s) _____ Location of Light(s) _____

Meter No. _____ Account No. _____

JETS WO No. _____ **CUSTOMER-OWNED FIXTURE(S):**

High Pressure Sodium

_____ 8800 Lumen (100 Watts) Light(s) to be billed at a base rate of $~~0.95~~1.00 each per month $_____
_____ 25000 Lumen (250 Watts) Light(s) to be billed at a base rate of $~~2.31~~2.45 each per month $_____
_____ 46000 Lumen (400 Watts) Light(s) to be billed at a base rate of $~~3.79~~4.01 each per month $_____
_____ 125000 Lumen (1000 Watts) Light(s) to be billed at a base rate of $~~8.78~~9.28 each per month $_____

Metal Halide

_____ 12000 Lumen (175 Watts) Light(s) to be billed at a base rate of $~~1.66~~1.76 each per month $_____
_____ 13000 Lumen (150 Watts PS) Light(s) to be billed at a base rate of $~~1.51~~1.59 each per month $_____
_____ 32000 Lumen (400 Watts) Light(s) to be billed at a base rate of $~~3.77~~3.99 each per month $_____
_____ 100000 Lumen (1000 Watts) Light(s) to be billed at a base rate of $~~8.76~~9.25 each per month $_____

All others to be billed as follows:

_____ Light(s) @ a base rate of $_____ * each per month (kWh for one light = _____) $_____
_____ Light(s) @ a base rate of $_____ * each per month (kWh for one light = _____) $_____
_____ Light(s) @ a base rate of $_____ * each per month kWh for one light = _____) $_____
Total Base Monthly Charge** $_____

* This base rate per light is calculated by taking the kWh for one light and multiplying by $~~0.02316~~0.02448/kWh. Repeat this line for each different type of customer-owned light other than the 8800 Lumen, 12000 Lumen, 13000 Lumen, 25000 Lumen, 32000 Lumen, 46000 Lumen, 100000 Lumen, or 125000 Lumen lights shown above.

** Base monthly charge does not include Fuel Charge, Purchased Power Capacity Charge, Environmental Charge, Energy Conservation Charge, Natural Disaster Recovery Surcharge, applicable taxes, or fees.

The Applicant requests the necessary electric energy for the operation thereof for the fixtures described above and hereby agrees to take and pay for the same in accordance with and subject to the Company's Rate Schedule "OS (PART I/II)" and Rules and Regulations for Electric Service on file in its office and on file with the Florida Public Service Commission or any changes therein as approved by the Florida Public Service Commission. This agreement and the monthly rates set forth above cover the electric service. The distribution system shall serve no other electrical loads except the lighting equipment described above.

GULF POWER
A SOUTHERN COMPANY

Section No. VIII
~~Second~~Third Revised Sheet No. 8.0
Canceling ~~First~~Second Revised Sheet No. 8.0

~~The special contracts listed below are on file in a special binder in the Rate Department of the Florida Public Service Commission pursuant to Commission Rule 25-9.34(3).~~

~~1. U. S. Department of the Navy (Naval Air Station - Pensacola, Florida)~~

~~2. Gold Kist, Inc.~~

~~3. Monsanto~~

~~4. City of Lynn Haven, Florida~~

~~5. City of Pensacola, Florida~~

~~6. Exxon~~

~~7. Air Products~~

~~8. General Services Administration~~

~~9. Southwest Forest~~

~~10. St. Regis Paper Company~~

~~11. Panama City Beach, Florida~~Gulf does not presently have in place any special contracts for the sale of electricity.

ISSUED BY: ~~D. L. McCrary~~S. W. Connally, Jr. **~~EFFECTIVE:~~** ~~June 8, 1987~~

Schedule E-15	PROJECTED BILLING DETERMINANTS - DERIVATION	Page 1 of 1
FLORIDA PUBLIC SERVICE COMMISSION COMPANY: GULF POWER COMPANY DOCKET NO.: 130140-EI	EXPLANATION: Trace how the billing determinants were derived from the preliminary forecasts used for test year budget. Provide supporting assumptions and details of forecasting techniques. Reconcile the billing determinants with the forecast by customer class determinants with the forecast by customer class in the Ten-Year-Site Plan.	Type of Data Shown: __X__Projected Test Year Ended 12/31/14 ____Prior Year Ended 12/31/13 ____Historical Year Ended 12/31/12 Witness: R. J. Alexander

Derivation of Billing Determinants - Summary

Line No.

1 The following summarizes the derivation of billing determinants used in the test year budget. Additional detail is included in Gulf Witness Alexander's
2 testimony.

3 Customers:

4 The residential, commercial and industrial non-lighting customer forecasts, by rate, were based primarily on input from Gulf's field Marketing Managers
5 with the assistance of their field employees.

6 Outdoor lighting customer projections, by rate and class, were derived from historical growth rates and input from Gulf's lighting team.

7 Energy Sales and Billing Demand:

8 Residential and commercial class-level non-lighting energy projections were developed using multiple linear regression models. Historical ratios were
9 then used to develop energy projections by rate.

10 Annual energy sales and billing demand projections for the largest industrial and commercial customers were based on one-on-one customer interviews.
11 Projections of monthly energy and billing demand were derived from these annual projections using historical relationships between monthly and annual
12 values. Monthly energy projections, by rate, for small industrial customers were developed using historical averages.

13 The rate-level billing demands for commercial and small industrial customers were developed using historical relationships between energy and demand.

14 Outdoor lighting energy was projected by rate and class using historical growth rates and input from Gulf's lighting team.

15 The projected billing determinants, by class, are consistent with the forecast utilized in the 2013 Ten Year Site Plan.

Supporting Schedules: Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide a schedule of the number of customers served at transmission, subtransmission, primary distribution, and secondary distribution voltages by rate schedule for the test year and prior year. (Customers served directly from a company-owned substation must be listed under the voltage level at which they are served.)

Type of Data Shown:
X Projected Test Year Ended 12/31/14
__ Prior Year Ended 12/31/13
__ Historical Year Ended 12/31/12
Witness: M. T. O'Sheasy, J. I. Thompson

(1) LINE NO.	(2) RATE SCHEDULE	(3) AVERAGE CUSTOMERS	(4) TRANSMISSION (LEVEL 2) CUSTOMERS	(5) SUB-TRANSMISSION (LEVEL 3) CUSTOMERS	(6) PRIMARY DISTRIBUTION (LEVEL 4) CUSTOMERS	(7) SECONDARY DISTRIBUTION (LEVEL 5) CUSTOMERS
1	RATE CLASS RESIDENTIAL	386,033	0	0	0	386,033
2	RATE CLASS GS/GST	29,156	0	0	2	29,154
3	RATE CLASS GSD/GSDT	17,497	0	3	28	17,466
4	RATE CLASS LP/LPT	284	0	8	28	248
5	RATE CLASS MAJOR ACCOUNTS	68	3	17	15	33
6	RATE CLASS OS	10,312	0	0	0	10,312
7	SUBTOTAL RETAIL	443,350	3	28	73	443,246
8	WHOLESALE	1	0	1	0	0
9	TOTAL	443,351	3	29	73	443,246

Supporting Schedules: Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide a schedule of the number of customers served at transmission, subtransmission, primary distribution, and secondary distribution voltages by rate schedule for the test year and prior year. (Customers served directly from a company-owned substation must be listed under the voltage level at which they are served.)

Type of Data Shown:
_ Projected Test Year Ended 12/31/14
X Prior Year Ended 12/31/13
_ Historical Year Ended 12/31/12
Witness: M. T. O'Sheasy, J. I. Thompson

(1) LINE NO.	(2) RATE SCHEDULE	(3) AVERAGE CUSTOMERS	(4) TRANSMISSION (LEVEL 2) CUSTOMERS	(5) SUB-TRANSMISSION (LEVEL 3) CUSTOMERS	(6) PRIMARY DISTRIBUTION (LEVEL 4) CUSTOMERS	(7) SECONDARY DISTRIBUTION (LEVEL 5) CUSTOMERS
1	RATE CLASS RESIDENTIAL	381,245	0	0	0	381,245
2	RATE CLASS GS/GST	28,898	0	0	2	28,896
3	RATE CLASS GSD/GSDT	17,277	0	3	28	17,246
4	RATE CLASS LP/LPT	280	0	8	28	244
5	RATE CLASS MAJOR ACCOUNTS	68	3	17	15	33
6	RATE CLASS OS	10,281	0	0	0	10,281
7	SUBTOTAL RETAIL	438,049	3	28	73	437,945
8	WHOLESALE	1	0	1	0	0
9	TOTAL	438,050	3	29	73	437,945

Supporting Schedules:

Recap Schedules:

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FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: For each rate class that is not 100% metered by time recording meters, provide the estimated historic value and 90% confidence interval by month from the latest load research for (1) contribution to monthly system peaks (coincident), (2) monthly noncoincident peak (class peaks) and (3) monthly customer maximum demand (billing demand for demand classes). For classes that are 100% metered with time recording meters, provide actual monthly values for the aforementioned demands and identify such as actual values. Provide the annual kWh as well as the 12 CP Load Factor, Class NCP Load Factor and the Customer Load Factor for each class.

Type of Data Shown:
____Projected Test Year Ended 12/31/14
____Prior Year Ended 12/31/13
__X__Historical Year Ended 12/31/09
Witness: J. I. Thompson

(1) Line No.	(2) Rate Schedule	(3) Month and Year	(4) Estimated Coincident Peak (kW)	(5) 90% Confidence Interval (kW)	(6) Estimated Noncoincident (Class) Peak (kW)	(7) 90% Confidence Interval (kW)	(8) Estimated Customer Maximum Demand (kW)	(9) 90% Confidence Interval (kW)
1	RS	Jan 2009	1,256,412	89,180	1,256,412	89,180	NA	NA
2	RS	Feb 2009	1,254,706	80,289	1,254,706	80,289	NA	NA
3	RS	Mar 2009	1,015,608	77,018	1,032,663	89,637	NA	NA
4	RS	Apr 2009	666,873	51,288	735,990	75,579	NA	NA
5	RS	May 2009	992,949	63,445	1,041,385	54,900	NA	NA
6	RS	Jun 2009	1,241,857	76,681	1,261,150	74,705	NA	NA
7	RS	Jul 2009	1,128,213	73,521	1,205,823	61,885	NA	NA
8	RS	Aug 2009	1,074,969	51,367	1,122,780	53,666	NA	NA
9	RS	Sep 2009	1,004,191	45,356	1,024,960	59,208	NA	NA
10	RS	Oct 2009	989,040	47,727	1,016,996	45,974	NA	NA
11	RS	Nov 2009	509,285	49,259	671,467	78,239	NA	NA
12	RS	Dec 2009	1,063,944	96,027	1,063,944	96,027	NA	NA

13	Annual Peak:	1,261,150	Annual kWh:	5,029,384,426
14	12 Coincident Peak Average:	1,016,504	12 CP Load Factor:	0.56
15	90% Confidence Interval:	29,765	Class NCP Load Factor:	0.46
16	Customer Maximum Demand:	NA	Customer Maximum Demand Load Factor:	NA

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: For each rate class that is not 100% metered by time recording meters, provide the estimated historic value and 90% confidence interval by month from the latest load research for (1) contribution to monthly system peaks (coincident), (2) monthly noncoincident peak (class peaks) and (3) monthly customer maximum demand (billing demand for demand classes). For classes that are 100% metered with time recording meters, provide actual monthly values for the aforementioned demands and identify such as actual values. Provide the annual kWh as well as the 12 CP Load Factor, Class NCP Load Factor and the Customer Load Factor for each class.

Type of Data Shown:
____Projected Test Year Ended 12/31/14
____Prior Year Ended 12/31/13
__X__Historical Year Ended 12/31/09
Witness: J. I. Thompson

(1) Line No.	(2) Rate Schedule	(3) Month and Year	(4) Estimated Coincident Peak (kW)	(5) 90% Confidence Interval (kW)	(6) Estimated Noncoincident (Class) Peak (kW)	(7) 90% Confidence Interval (kW)	(8) Estimated Customer Maximum Demand (kW)	(9) 90% Confidence Interval (kW)
1	RSVP	Jan 2009	22,921	2,175	36,924	2,644	NA	NA
2	RSVP	Feb 2009	25,920	2,083	41,484	2,877	NA	NA
3	RSVP	Mar 2009	28,698	2,501	32,453	2,465	NA	NA
4	RSVP	Apr 2009	22,430	1,521	25,626	1,708	NA	NA
5	RSVP	May 2009	24,614	1,632	35,452	1,792	NA	NA
6	RSVP	Jun 2009	35,540	1,569	46,027	1,780	NA	NA
7	RSVP	Jul 2009	28,221	1,877	42,689	1,779	NA	NA
8	RSVP	Aug 2009	28,358	1,607	38,389	1,802	NA	NA
9	RSVP	Sep 2009	26,171	1,889	39,511	1,934	NA	NA
10	RSVP	Oct 2009	23,773	1,480	35,784	1,813	NA	NA
11	RSVP	Nov 2009	16,285	1,098	25,456	1,628	NA	NA
12	RSVP	Dec 2009	26,979	2,459	34,326	2,018	NA	NA

13	Annual Peak:	46,027	Annual kWh:	163,939,548
14	12 Coincident Peak Average:	25,826	12 CP Load Factor:	0.72
15	90% Confidence Interval:	1,016	Class NCP Load Factor:	0.41
16	Customer Maximum Demand:	NA	Customer Maximum Demand Load Factor:	NA

Supporting Schedules: Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: For each rate class that is not 100% metered by time recording meters, provide the estimated historic value and 90% confidence interval by month from the latest load research for (1) contribution to monthly system peaks (coincident), (2) monthly noncoincident peak (class peaks) and (3) monthly customer maximum demand (billing demand for demand classes). For classes that are 100% metered with time recording meters, provide actual monthly values for the aforementioned demands and identify such as actual values. Provide the annual kWh as well as the 12 CP Load Factor, Class NCP Load Factor and the Customer Load Factor for each class.

Type of Data Shown:
____Projected Test Year Ended 12/31/14
____Prior Year Ended 12/31/13
__X__Historical Year Ended 12/31/09
Witness: J. I. Thompson

(1) Line No.	(2) Rate Schedule	(3) Month and Year	(4) Estimated Coincident Peak (kW)	(5) 90% Confidence Interval (kW)	(6) Estimated Noncoincident (Class) Peak (kW)	(7) 90% Confidence Interval (kW)	(8) Estimated Customer Maximum Demand (kW)	(9) 90% Confidence Interval (kW)
1	GS	Jan 2009	51,474	4,757	60,800	7,248	NA	NA
2	GS	Feb 2009	57,279	5,145	58,098	5,548	NA	NA
3	GS	Mar 2009	44,408	4,295	49,892	5,533	NA	NA
4	GS	Apr 2009	43,434	3,173	49,746	4,258	NA	NA
5	GS	May 2009	50,389	3,641	57,745	4,647	NA	NA
6	GS	Jun 2009	59,523	3,821	69,337	3,982	NA	NA
7	GS	Jul 2009	63,991	5,850	66,862	3,910	NA	NA
8	GS	Aug 2009	55,469	4,875	63,913	4,158	NA	NA
9	GS	Sep 2009	55,047	5,157	59,389	4,772	NA	NA
10	GS	Oct 2009	52,445	4,893	59,200	4,318	NA	NA
11	GS	Nov 2009	28,189	2,234	38,804	4,181	NA	NA
12	GS	Dec 2009	47,013	5,513	53,248	6,712	NA	NA

13	Annual Peak:	69,337	Annual kWh:	278,595,794
14	12 Coincident Peak Average:	50,722	12 CP Load Factor:	0.63
15	90% Confidence Interval:	2,997	Class NCP Load Factor:	0.46
16	Customer Maximum Demand:	NA	Customer Maximum Demand Load Factor:	NA

Supporting Schedules: Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: For each rate class that is not 100% metered by time recording meters, provide the estimated historic value and 90% confidence interval by month from the latest load research for (1) contribution to monthly system peaks (coincident), (2) monthly noncoincident peak (class peaks) and (3) monthly customer maximum demand (billing demand for demand classes). For classes that are 100% metered with time recording meters, provide actual monthly values for the aforementioned demands and identify such as actual values. Provide the annual kWh as well as the 12 CP Load Factor, Class NCP Load Factor and the Customer Load Factor for each class.

Type of Data Shown:
____Projected Test Year Ended 12/31/14
____Prior Year Ended 12/31/13
_X_Historical Year Ended 12/31/09
Witness: J. I. Thompson

(1) Line No.	(2) Rate Schedule	(3) Month and Year	(4) Estimated Coincident Peak (kW)	(5) 90% Confidence Interval (kW)	(6) Estimated Noncoincident (Class) Peak (kW)	(7) 90% Confidence Interval (kW)	(8) Estimated Customer Maximum Demand (kW)	(9) 90% Confidence Interval (kW)
1	GSD/GSDT	Jan 2009	334,985	27,983	385,684	32,993	691,674	NA
2	GSD/GSDT	Feb 2009	355,172	26,914	395,377	31,189	700,771	NA
3	GSD/GSDT	Mar 2009	339,793	28,922	377,687	23,018	685,311	NA
4	GSD/GSDT	Apr 2009	390,544	19,754	423,857	24,480	638,762	NA
5	GSD/GSDT	May 2009	430,117	23,939	502,974	28,731	683,401	NA
6	GSD/GSDT	Jun 2009	494,719	24,655	535,406	24,585	715,495	NA
7	GSD/GSDT	Jul 2009	512,150	22,817	512,150	22,817	736,600	NA
8	GSD/GSDT	Aug 2009	481,030	20,894	494,629	20,707	725,764	NA
9	GSD/GSDT	Sep 2009	463,689	21,846	491,596	27,702	716,891	NA
10	GSD/GSDT	Oct 2009	467,419	24,651	483,863	26,817	713,944	NA
11	GSD/GSDT	Nov 2009	305,264	16,861	353,536	19,967	649,370	NA
12	GSD/GSDT	Dec 2009	298,198	23,562	354,679	27,807	651,346	NA

13	Annual Peak:	535,406	Annual kWh:	2,608,986,480
14	12 Coincident Peak Average:	406,090	12 CP Load Factor:	0.73
15	90% Confidence Interval:	14,637	Class NCP Load Factor:	0.56
16	Customer Maximum Demand:	736,600	Customer Maximum Demand Load Factor:	0.40

Supporting Schedules: Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: For each rate class that is not 100% metered by time recording meters, provide the estimated historic value and 90% confidence interval by month from the latest load research for (1) contribution to monthly system peaks (coincident), (2) monthly noncoincident peak (class peaks) and (3) monthly customer maximum demand (billing demand for demand classes). For classes that are 100% metered with time recording meters, provide actual monthly values for the aforementioned demands and identify such as actual values. Provide the annual kWh as well as the 12 CP Load Factor, Class NCP Load Factor and the Customer Load Factor for each class.

Type of Data Shown:
____Projected Test Year Ended 12/31/14
____Prior Year Ended 12/31/13
__X__Historical Year Ended 12/31/09
Witness: J. I. Thompson

(1) Line No.	(2) Rate Schedule	(3) Month and Year	(4) Estimated Coincident Peak (kW)	(5) 90% Confidence Interval (kW)	(6) Estimated Noncoincident (Class) Peak (kW)	(7) 90% Confidence Interval (kW)	(8) Estimated Customer Maximum Demand (kW)	(9) 90% Confidence Interval (kW)
1	LP	Jan 2009	59,229	5,182	85,243	6,606	102,609	NA
2	LP	Feb 2009	59,978	4,702	79,936	5,325	100,533	NA
3	LP	Mar 2009	56,051	4,593	81,112	5,147	99,739	NA
4	LP	Apr 2009	80,833	4,259	86,657	5,432	100,035	NA
5	LP	May 2009	76,161	4,650	91,612	5,562	108,029	NA
6	LP	Jun 2009	87,660	5,131	94,653	5,170	112,012	NA
7	LP	Jul 2009	92,304	4,933	92,304	4,933	113,057	NA
8	LP	Aug 2009	86,942	4,909	89,664	5,374	109,155	NA
9	LP	Sep 2009	87,503	4,530	94,222	5,438	111,298	NA
10	LP	Oct 2009	96,561	5,157	98,045	4,687	112,031	NA
11	LP	Nov 2009	69,234	4,270	76,573	4,694	107,057	NA
12	LP	Dec 2009	50,645	5,132	81,755	5,306	96,865	NA

13	Annual Peak:	98,045	Annual kWh:	545,057,020
14	12 Coincident Peak Average:	75,258	12 CP Load Factor:	0.83
15	90% Confidence Interval:	2,760	Class NCP Load Factor:	0.63
16	Customer Maximum Demand:	113,057	Customer Maximum Demand Load Factor:	0.55

Supporting Schedules: Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: For each rate class that is not 100% metered by time recording meters, provide the estimated historic value and 90% confidence interval by month from the latest load research for (1) contribution to monthly system peaks (coincident), (2) monthly noncoincident peak (class peaks) and (3) monthly customer maximum demand (billing demand for demand classes). For classes that are 100% metered with time recording meters, provide actual monthly values for the aforementioned demands and identify such as actual values. Provide the annual kWh as well as the 12 CP Load Factor, Class NCP Load Factor and the Customer Load Factor for each class.

Type of Data Shown:
____Projected Test Year Ended 12/31/14
____Prior Year Ended 12/31/13
__X__Historical Year Ended 12/31/09
Witness: J. I. Thompson

(1) Line No.	(2) Rate Schedule	(3) Month and Year	(4) Estimated Coincident Peak (kW)	(5) 90% Confidence Interval (kW)	(6) Estimated Noncoincident (Class) Peak (kW)	(7) 90% Confidence Interval (kW)	(8) Estimated Customer Maximum Demand (kW)	(9) 90% Confidence Interval (kW)
1	LPT	Jan 2009	142,481	3,843	155,085	2,889	170,008	NA
2	LPT	Feb 2009	146,093	2,948	155,397	2,353	168,640	NA
3	LPT	Mar 2009	128,690	2,487	149,321	3,324	172,691	NA
4	LPT	Apr 2009	165,610	2,339	174,587	2,733	178,718	NA
5	LPT	May 2009	152,931	3,119	164,018	3,212	194,071	NA
6	LPT	Jun 2009	190,068	2,258	199,921	2,904	212,701	NA
7	LPT	Jul 2009	197,710	3,045	205,339	2,979	217,370	NA
8	LPT	Aug 2009	201,413	2,387	205,188	1,819	213,566	NA
9	LPT	Sep 2009	190,649	2,393	198,160	2,074	203,953	NA
10	LPT	Oct 2009	199,960	3,893	205,569	4,066	207,915	NA
11	LPT	Nov 2009	154,350	2,950	169,408	3,110	175,254	NA
12	LPT	Dec 2009	121,608	1,833	146,639	3,118	166,195	NA

13	Annual Peak:	205,569	Annual kWh:	1,222,967,267
14	12 Coincident Peak Average:	165,964	12 CP Load Factor:	0.84
15	90% Confidence Interval:	1,577	Class NCP Load Factor:	0.68
16	Customer Maximum Demand:	217,370	Customer Maximum Demand Load Factor:	0.64

Supporting Schedules: Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: For each rate class that is not 100% metered by time recording meters, provide the estimated historic value and 90% confidence interval by month from the latest load research for (1) contribution to monthly system peaks (coincident), (2) monthly noncoincident peak (class peaks) and (3) monthly customer maximum demand (billing demand for demand classes). For classes that are 100% metered with time recording meters, provide actual monthly values for the aforementioned demands and identify such as actual values. Provide the annual kWh as well as the 12 CP Load Factor, Class NCP Load Factor and the Customer Load Factor for each class.

Type of Data Shown:
____Projected Test Year Ended 12/31/14
____Prior Year Ended 12/31/13
_X_Historical Year Ended 12/31/09
Witness: J. I. Thompson

(1) Line No.	(2) Rate Schedule	(3) Month and Year	(4) Estimated Coincident Peak (kW)	(5) 90% Confidence Interval (kW)	(6) Estimated Noncoincident (Class) Peak (kW)	(7) 90% Confidence Interval (kW)	(8) Estimated Customer Maximum Demand (kW)	(9) 90% Confidence Interval (kW)
1	Major Accounts	Jan 2009	106,915	Actual Value	124,886	Actual Value	193,236	Actual Value
2	Major Accounts	Feb 2009	94,526	Actual Value	146,897	Actual Value	192,155	Actual Value
3	Major Accounts	Mar 2009	83,036	Actual Value	143,841	Actual Value	188,994	Actual Value
4	Major Accounts	Apr 2009	134,564	Actual Value	152,010	Actual Value	191,476	Actual Value
5	Major Accounts	May 2009	91,184	Actual Value	168,675	Actual Value	198,086	Actual Value
6	Major Accounts	Jun 2009	92,068	Actual Value	117,450	Actual Value	171,899	Actual Value
7	Major Accounts	Jul 2009	89,664	Actual Value	121,124	Actual Value	153,000	Actual Value
8	Major Accounts	Aug 2009	93,087	Actual Value	152,098	Actual Value	185,426	Actual Value
9	Major Accounts	Sep 2009	88,227	Actual Value	132,788	Actual Value	166,445	Actual Value
10	Major Accounts	Oct 2009	105,064	Actual Value	169,985	Actual Value	250,407	Actual Value
11	Major Accounts	Nov 2009	152,058	Actual Value	162,056	Actual Value	207,563	Actual Value
12	Major Accounts	Dec 2009	81,915	Actual Value	127,161	Actual Value	175,655	Actual Value

13	Annual Peak:	169,985	Annual kWh:	834,945,562
14	12 Coincident Peak Average:	101,026	12 CP Load Factor:	0.94
15	90% Confidence Interval:	NA	Class NCP Load Factor:	0.56
16	Customer Maximum Demand:	250,407	Customer Maximum Demand Load Factor:	0.38

Supporting Schedules: Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide monthly peaks for the test year and the five previous years.

Type of Data Shown:
___ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
_X_ Historical Years Ended 12/31/09 - 12/31/10
Witness: R. J. Alexander

(1) Line No.	(2) Year	(3) Month	(4) Peak in MW	(5) Day of Week	(6) Day of Month	(7) Hour Ending	(8) Actual (A) or Estimated (E)
1	2009	Jan	2,292	Wednesday	21	700	A
2	2009	Feb	2,320	Thursday	5	700	A
3	2009	Mar	1,930	Tuesday	3	700	A
4	2009	Apr	1,674	Wednesday	29	1700	A
5	2009	May	2,055	Thursday	28	1700	A
6	2009	Jun	2,546	Monday	22	1700	A
7	2009	Jul	2,429	Thursday	2	1400	A
8	2009	Aug	2,317	Monday	10	1600	A
9	2009	Sep	2,180	Friday	25	1600	A
10	2009	Oct	2,202	Wednesday	7	1600	A
11	2009	Nov	1,387	Wednesday	4	1800	A
12	2009	Dec	1,932	Tuesday	29	700	A
13	2010	Jan	2,553	Monday	11	700	A
14	2010	Feb	2,144	Wednesday	17	700	A
15	2010	Mar	1,934	Thursday	4	700	A
16	2010	Apr	1,488	Sunday	25	1700	A
17	2010	May	2,219	Monday	24	1600	A
18	2010	Jun	2,419	Monday	14	1400	A
19	2010	Jul	2,525	Friday	30	1700	A
20	2010	Aug	2,458	Sunday	1	1600	A
21	2010	Sep	2,300	Sunday	12	1700	A
22	2010	Oct	1,881	Wednesday	27	1500	A
23	2010	Nov	1,574	Monday	1	1900	A
24	2010	Dec	2,314	Tuesday	14	700	A

Supporting Schedules: Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide monthly peaks for the test year and the five previous years.

Type of Data Shown:
___ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
_X_ Historical Years Ended 12/31/11 - 12/31/12
Witness: R. J. Alexander

(1) Line No.	(2) Year	(3) Month	(4) Peak in MW	(5) Day of Week	(6) Day of Month	(7) Hour Ending	(8) Actual (A) or Estimated (E)
1	2011	Jan	2,495	Thursday	13	700	A
2	2011	Feb	2,107	Friday	11	800	A
3	2011	Mar	1,682	Monday	28	1700	A
4	2011	Apr	1,810	Wednesday	27	1500	A
5	2011	May	2,228	Tuesday	31	1700	A
6	2011	Jun	2,432	Tuesday	14	1700	A
7	2011	Jul	2,382	Sunday	10	1600	A
8	2011	Aug	2,535	Thursday	4	1600	A
9	2011	Sep	2,115	Wednesday	14	1600	A
10	2011	Oct	1,691	Monday	17	1700	A
11	2011	Nov	1,564	Wednesday	30	2000	A
12	2011	Dec	1,771	Thursday	1	700	A
13	2012	Jan	2,139	Wednesday	4	700	A
14	2012	Feb	1,917	Monday	13	800	A
15	2012	Mar	1,579	Wednesday	28	1800	A
16	2012	Apr	1,901	Monday	30	1600	A
17	2012	May	2,253	Tuesday	29	1600	A
18	2012	Jun	2,295	Friday	29	1700	A
19	2012	Jul	2,337	Tuesday	3	1500	A
20	2012	Aug	2,351	Wednesday	1	1700	A
21	2012	Sep	2,186	Monday	3	1700	A
22	2012	Oct	1,852	Saturday	6	1600	A
23	2012	Nov	1,457	Thursday	29	800	A
24	2012	Dec	1,766	Sunday	30	800	A

Supporting Schedules: Recap Schedules:

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FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide monthly peaks for the test year and the five previous years.

Type of Data Shown:
_X_ Projected Test Year Ended 12/31/14
_X_ Prior Year Ended 12/31/13
___ Historical Year Ended 12/31/12
Witness: R. J. Alexander

(1) Line No.	(2) Year	(3) Month	(4) Peak in MW	(5) Day of Week	(6) Day of Month	(7) Hour Ending	(8) Actual (A) or Estimated (E)
1	2013	Jan	1,739	Friday	4	800	A
2	2013	Feb	1,731	Sunday	17	800	A
3	2013	Mar	1,840	Monday	4	700	A
4	2013	Apr	1,611	Tuesday	16	1700	A
5	2013	May	2,069	Thursday	23	1700	A
6	2013	Jun	2,312	Wednesday	12	1700	A
7	2013	Jul	2,514	Thursday	18	1700	E
8	2013	Aug	2,476	Thursday	15	1700	E
9	2013	Sep	2,325	Thursday	5	1500	E
10	2013	Oct	2,023	Tuesday	22	1600	E
11	2013	Nov	1,751	Wednesday	27	800	E
12	2013	Dec	2,132	Tuesday	17	800	E
13	2014	Jan	2,318	Thursday	2	800	E
14	2014	Feb	2,057	Wednesday	5	800	E
15	2014	Mar	1,742	Friday	14	800	E
16	2014	Apr	1,748	Thursday	24	1700	E
17	2014	May	2,289	Tuesday	27	1600	E
18	2014	Jun	2,417	Tuesday	10	1700	E
19	2014	Jul	2,522	Thursday	17	1700	E
20	2014	Aug	2,481	Thursday	14	1700	E
21	2014	Sep	2,329	Thursday	4	1500	E
22	2014	Oct	2,031	Tuesday	21	1600	E
23	2014	Nov	1,747	Wednesday	26	800	E
24	2014	Dec	2,111	Tuesday	16	800	E

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Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide estimates of demand and energy losses for transmission and distribution system components and explain the methodology used in determining losses.

Type of Data Shown:
X Projected Test Year Ended 12/31/14
__ Prior Year Ended 12/31/13
__ Historical Year Ended 12/31/12
Witness: M. T. O'Sheasy

(1) LINE NO.	(2) COMPONENT	(3) ENERGY LOSSES	(4) DEMAND LOSSES WINTER PEAK	(5) DEMAND LOSSES SUMMER PEAK	(6) DEMAND LOSSES 12 CP AVG
1	TRANSMISSION SYSTEM				
2	LEVEL 2 -- Transmission Lines	1.15980%	1.96886%	2.09633%	1.85823%
3	LEVEL 3 -- Transmission Substations	0.35991%	0.47548%	0.50555%	0.44804%
4	LEVEL 3 -- Directly Assigned Subtransmission	N/A	N/A	N/A	N/A
5	DISTRIBUTION SYSTEM				
6	LEVEL 3 -- Distribution Substations	0.35991%	0.47548%	0.50555%	0.44804%
7	LEVEL 4 -- Distribution Primary Lines	2.72918%	4.13249%	4.40044%	3.88614%
8	(4 KV to 12 KV)				
9	LEVEL 4 -- Distribution Primary Services	2.72918%	4.13249%	4.40044%	3.88614%
10	LEVEL 5 -- Distribution Line Transformers	2.79083%	4.11637%	4.39456%	3.86213%
11	and Secondary Lines & Drops				

12 Methodology and Assumptions Used to Determine Losses:
13 Energy and Demand losses were calculated by applying historical loss factors to the test year budgeted territorial sales.
14 Please refer to MFR E-10 for Gulf Power Company's voltage levels of service and Mr. O'Sheasy's testimony for a
15 description of the percent - loss calculation.

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Supporting Schedules:

Recap Schedules:

Schedule E-19b | ENERGY LOSSES | Page 1 of 1

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Show energy losses by rate schedule for the test year and explain the methodology and assumptions used in determining these losses.

Type of Data Shown:
X Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
___ Historical Year Ended 12/31/12
Witness: M. T. O'Sheasy

(1) LINE NO.	(2) RATE SCHEDULE	(3) VOLTAGE LEVEL	(4) ENERGY AT GENERATION	(5) SALES AT METER	(6) LOSSES & CO. USE - MWH	(7) PERCENT LOSSES	(8) DELIVERED EFFICIENCY	(9) COMPANY USE	(10) SYSTEM LOSSES
1	RATE CLASS RESIDENTIAL	5	5,643,768	5,264,445	379,323	6.721%	0.93279	11,361	367,962
2	RATE CLASS GS	5	312,264	291,278	20,986	6.721%	0.93279	629	20,357
3		4	6	5	1	16.667%	0.83333	0	1
4	RATE CLASS GSD	5	2,914,575	2,718,685	195,890	6.721%	0.93279	5,867	190,023
5		4	14,056	13,477	579	4.119%	0.95881	18	561
6		3	1,549	1,525	24	1.549%	0.98451	1	23
7	RATE CLASS LP/LPT	5	833,254	777,250	56,004	6.721%	0.93279	1,677	54,327
8		4	291,458	279,456	12,002	4.118%	0.95882	369	11,633
9		3	179,644	176,948	2,696	1.501%	0.98499	85	2,611
10	RATE CLASS MAJOR	5	7,906	7,375	531	6.716%	0.93284	16	515
11	ACCOUNTS	4	319,064	305,926	13,138	4.118%	0.95882	403	12,735
12		3	948,063	931,863	14,200	1.501%	0.98499	446	13,754
13		2	235,151	232,455	2,696	1.146%	0.98854	85	2,611
14	RATE CLASS OS	5	164,657	153,590	11,067	6.721%	0.93279	331	10,736
15	TOTAL RETAIL		11,863,415	11,154,278	709,137	5.978%	0.94022	21,268	687,849
16	WHOLESALE	3	356,397	351,048	5,349	1.501%	0.98499	168	5,181
17	TOTAL SYSTEM		12,219,812	11,505,326	714,486	5.847%	0.94153	21,456	693,030

18 Methodology and Assumptions Used to Determine Losses:

19 Energy losses were calculated by applying the system energy loss factors to sales by rate level. See Mr. O'Sheasy's testimony for a description.

Supporting Schedules: | Recap Schedules:

Schedule E-19c | DEMAND LOSSES | Page 1 of 1

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Show maximum demand losses by rate schedule for the test year, and explain the methodology and assumptions used in determining losses.

Type of Data Shown:
X Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
___ Historical Year Ended 12/31/12
Witness: M. T. O'Sheasy

(1) LINE NO.	(2) RATE SCHEDULE	(3) VOLTAGE LEVEL	(4) 12 MO. AVG. COINC. DEMAND AT GENERATION	(5) 12 MO. AVG. COINC. PEAK AT METER	(6) TOTAL LOSSES & CO. USE - MW	(7) PERCENT LOSSES	(8) COMPANY USE	(9) SYSTEM LOSSES
1	RATE CLASS RESIDENTIAL	5	1,144,164	1,036,422	107,742	9.41666%	2,202	105,540
2	RATE CLASS GS	5	55,757	50,506	5,251	9.41765%	107	5,144
3		4	1	1	0	0.00000%	0	0
4	RATE CLASS GSD	5	447,295	405,175	42,120	9.41660%	861	41,259
5		4	2,147	2,020	127	5.91523%	3	124
6		3	1,586	1,550	36	2.26986%	1	35
7	RATE CLASS LP/LPT	5	121,957	110,471	11,486	9.41607%	235	11,251
8		4	43,411	40,842	2,569	5.91785%	54	2,515
9		3	26,552	25,951	601	2.26348%	13	588
10	RATE CLASS MAJOR	5	1,245	1,128	117	9.39759%	2	115
11	ACCOUNTS	4	47,220	44,425	2,795	5.91910%	59	2,736
12		3	149,725	146,337	3,388	2.26282%	74	3,314
13		2	35,413	34,767	646	1.82419%	14	632
14	RATE CLASS OS	5	8,774	7,948	826	9.41418%	17	809
15	TOTAL RETAIL		2,085,247	1,907,543	177,704	8.52196%	3,642	174,062
16	WHOLESALE	3	64,086	62,636	1,450	2.26258%	32	1,418
17	TOTAL SYSTEM		2,149,333	1,970,179	179,154	8.33533%	3,674	175,480

Supporting Schedules:

Recap Schedules:

FILED JUL 12, 2013
DOCUMENT NO. 03981-13
FPSC - COMMISSION CLERK

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 130140-EI

GULF POWER

A SOUTHERN COMPANY

MINIMUM FILING REQUIREMENTS

SECTION F – MISCELLANEOUS SCHEDULES
VOLUME ONE

GULF POWER COMPANY

Docket No. 130140-EI
Minimum Filing Requirements

Index

F. Miscellaneous Schedules
Volume One

Schedules	Witness	Title	Page
F-1	Teel Erickson	Annual and Quarterly Reports to Shareholders	1
F-2	Teel Erickson	SEC Reports	2

Schedule F-1	ANNUAL AND QUARTERLY REPORTS TO SHAREHOLDERS	Page 1 of 1
FLORIDA PUBLIC SERVICE COMMISSION COMPANY: GULF POWER COMPANY DOCKET NO.: 130140-EI	EXPLANATION: Provide a copy of the most recent Annual Report to Shareholders and all subsequent Quarterly Reports. The company shall file all Quarterly and Annual Reports as they become available during the proceeding.	Type of Data Shown: ___Projected Test Year Ended 12/31/14 ___Prior Year Ended 12/31/13 _X_Historical Year Ended 12/31/12 Witness: R. S. Teel, C. J. Erickson

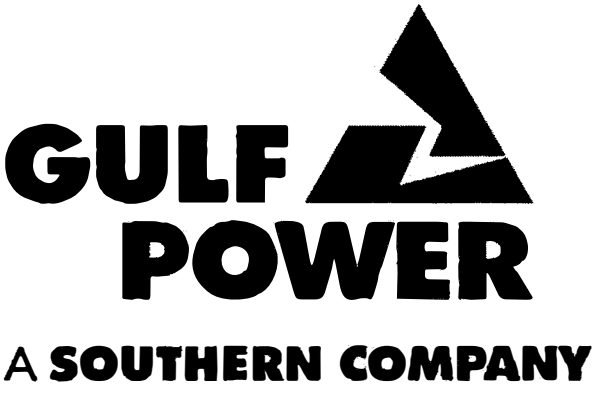
Line No.	
1	Gulf Power Company's 2012 Annual Report is attached.

Supporting Schedules:

Recap Schedules:

GULF POWER COMPANY

2012 ANNUAL REPORT



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Gulf Power Company 2012 Annual Report

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2 REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

3 MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

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69 SELECTED FINANCIAL AND OPERATING DATA

71 DIRECTORS AND OFFICERS

72 CORPORATE INFORMATION

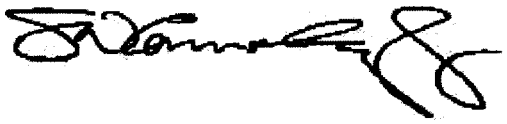
SUMMARY

	2012	2011	Percent Change
Financial Highlights *(in thousands)*:			
Operating revenues	**$1,439,762**	**$1,519,812**	(5.3)
Operating expenses	**1,171,568**	**1,295,088**	(9.5)
Net income after dividends on preference stock	**125,932**	**105,005**	19.9
Gross property additions	**325,237**	**337,830**	(3.7)
Total assets	**4,177,402**	**3,871,881**	7.9
Operating Data:			
Kilowatt-hour sales *(in thousands)*:			
Retail	**10,662,633**	**11,040,286**	(3.4)
Sales for resale - non-affiliates	**977,395**	**2,012,986**	(51.4)
Sales for resale – affiliates	**4,369,964**	**2,607,873**	67.6
Total	**16,009,992**	**15,661,145**	2.2
Customers served at year-end	**434,571**	**432,586**	0.5
Peak-hour demand, net *(in megawatts)*	**2,344**	**2,527**	(7.2)
Capitalization Ratios *(percent)*:			
Common stock equity	**47.9**	**45.8**	
Preference stock	**4.0**	**4.0**	
Long-term debt (excluding amounts due within one year)	**48.1**	**50.2**	
Return on Average Common Equity *(percent)*	**10.92**	**9.55**	

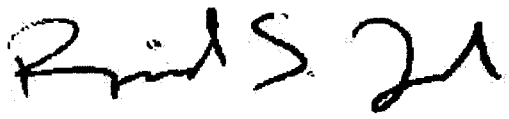
MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING
Gulf Power Company 2012 Annual Report

The management of Gulf Power Company (the Company) is responsible for establishing and maintaining an adequate system of internal control over financial reporting as required by the Sarbanes-Oxley Act of 2002 and as defined in Exchange Act Rule 13a-15(f). A control system can provide only reasonable, not absolute, assurance that the objectives of the control system are met.

Under management's supervision, an evaluation of the design and effectiveness of the Company's internal control over financial reporting was conducted based on the framework in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, management concluded that the Company's internal control over financial reporting was effective as of December 31, 2012.



S. W. Connally, Jr.
President and Chief Executive Officer



Richard S. Teel
Vice President and Chief Financial Officer

February 27, 2013

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of
Gulf Power Company

We have audited the accompanying balance sheets and statements of capitalization of Gulf Power Company (the Company) (a wholly owned subsidiary of The Southern Company) as of December 31, 2012 and 2011, and the related statements of income, comprehensive income, common stockholder's equity, and cash flows for each of the three years in the period ended December 31, 2012. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such financial statements (pages 27 to 67) present fairly, in all material respects, the financial position of Gulf Power Company as of December 31, 2012 and 2011, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2012, in conformity with accounting principles generally accepted in the United States of America.

Deloitte & Touche LLP

Atlanta, Georgia
February 27, 2013

OVERVIEW

Business Activities

Gulf Power Company (the Company) operates as a vertically integrated utility providing electricity to retail customers within its traditional service area located in northwest Florida and to wholesale customers in the Southeast.

Many factors affect the opportunities, challenges, and risks of the Company's business of selling electricity. These factors include the ability to maintain a constructive regulatory environment, to maintain and grow energy sales given economic conditions, and to effectively manage and secure timely recovery of costs. These costs include those related to projected long-term demand growth, increasingly stringent environmental standards, reliability, storm restoration following major storms, and fuel. Appropriately balancing required costs and capital expenditures with customer prices will continue to challenge the Company for the foreseeable future.

On March 12, 2012, the Florida Public Service Commission (PSC) approved an increase in retail base rates and charges of $64 million effective April 11, 2012. The amount of the increase includes the previously approved $38.5 million interim retail rate increase implemented in September 2011. The Florida PSC's decision on the amount of the increase also included a determination that none of the base rate revenues collected on an interim basis would be refunded. The Company's authorized retail return on equity (ROE) is a range of 9.25% to 11.25% with new retail base rates set at the midpoint retail ROE of 10.25%. In addition, the Florida PSC also approved a step increase to the Company's retail base rates and charges of $4 million effective in January 2013.

Key Performance Indicators

The Company continues to focus on several key performance indicators. These indicators include customer satisfaction, plant availability, system reliability, and net income after dividends on preference stock. The Company's financial success is directly tied to customer satisfaction. Key elements of ensuring customer satisfaction include outstanding service, high reliability, and competitive prices. Management uses customer satisfaction surveys and reliability indicators to evaluate the Company's results.

Peak season equivalent forced outage rate (Peak Season EFOR) is an indicator of plant availability and efficient generation fleet operations during the months when generation needs are greatest. The rate is calculated by dividing the number of hours of forced outages by total generation hours. The 2012 Peak Season EFOR was better than the target. Transmission and distribution system reliability performance is measured by the frequency and duration of outages. Performance targets for reliability are set internally based on historical performance. The transmission system performance for 2012 did not meet the target for these reliability measures. The distribution system performance for 2012 was better than the target for these reliability measures.

Net income after dividends on preference stock is the primary measure of the Company's financial performance. The Company's 2012 results compared with its targets for some of these key indicators are reflected in the following chart:

Key Performance Indicator	2012 Target Performance	2012 Actual Performance
Customer Satisfaction	**Top quartile in customer surveys**	**Top quartile**
Peak Season EFOR	**4.99% or less**	**0.67%**
Net Income After Dividends on Preference Stock	**$120.7 million**	**$125.9 million**

See RESULTS OF OPERATIONS herein for additional information on the Company's financial performance. The performance achieved in 2012 reflects the continued emphasis the Company places on reliability, customer satisfaction, and financial integrity, as well as the commitment shown by employees in achieving or exceeding management's expectations.

Earnings

The Company's 2012 net income after dividends on preference stock was $125.9 million, an increase of $20.9 million from the previous year. The increase in net income after dividends on preference stock in 2012 was primarily due to higher revenues due to increases in retail base rates and higher wholesale capacity revenues from non-affiliates in 2012. These increases were partially offset by milder weather in 2012, a decrease in retail energy sales in 2012 due to a decrease in customer usage, and a decrease in allowance for funds used during construction (AFUDC) equity, which is non-taxable.

In 2011, net income after dividends on preference stock was $105.0 million, a decrease of $16.5 million from the previous year. The decrease in net income after dividends on preference stock in 2011 was primarily due to an increase in other operations and maintenance expenses in 2011 and closer to normal weather in 2011 compared to 2010, partially offset by higher wholesale capacity revenues from non-affiliates.

RESULTS OF OPERATIONS

A condensed statement of income follows:

	Amount	Increase (Decrease) from Prior Year	
	2012	2012	2011
		(in millions)	
Operating revenues	$ 1,439.7	$ (80.1)	$ (70.4)
Fuel	544.9	(117.4)	(80.0)
Purchased power	74.1	(16.4)	(6.7)
Other operations and maintenance	314.2	2.8	30.7
Depreciation and amortization	141.0	11.4	8.2
Taxes other than income taxes	97.3	(3.9)	(0.5)
Total operating expenses	1,171.5	(123.5)	(48.3)
Operating income	268.2	43.4	(22.1)
Total other income and (expense)	(56.9)	(4.6)	(4.6)
Income taxes	79.2	17.9	(10.2)
Net income	132.1	20.9	(16.5)
Dividends on preference stock	6.2	—	—
Net income after dividends on preference stock	$ 125.9	$ 20.9	$ (16.5)

Operating Revenues

Operating revenues for 2012 were $1.44 billion, reflecting a decrease of $80.1 million from 2011. The following table summarizes the significant changes in operating revenues for the past two years:

	Amount	
	2012	2011
	(in millions)	
Retail — prior year	$ 1,208.5	$ 1,308.7
Estimated change in –		
Rates and pricing	62.7	2.0
Sales growth (decline)	(5.5)	3.9
Weather	(10.7)	(17.8)
Fuel and other cost recovery	(110.5)	(88.3)
Retail — current year	1,144.5	1,208.5
Wholesale revenues –		
Non-affiliates	106.9	133.6
Affiliates	123.6	111.3
Total wholesale revenues	230.5	244.9
Other operating revenues	64.7	66.4
Total operating revenues	$ 1,439.7	$ 1,519.8
Percent change	(5.3)%	(4.4)%

Retail revenues decreased $64.0 million, or 5.3%, in 2012 compared to 2011 primarily as a result of lower fuel revenues due to lower natural gas prices and lower energy sales due to milder weather in 2012 compared to 2011, partially offset by higher revenues resulting from increases in retail base rates. Retail revenues decreased $100.2 million, or 7.7%, in 2011 compared to 2010 primarily as a result of lower fuel revenues and lower energy sales due to closer to normal weather in 2011 compared to 2010, partially offset by an increase related to interim retail rate revenues. See "Energy Sales" below for a discussion of changes in the volume of energy sold, including changes related to sales growth (or decline) and weather.

Revenues associated with changes in rates and pricing include higher revenues due to increases in retail base rates and revenues associated with higher recoverable costs under the Company's energy conservation cost recovery clause, partially offset by a decrease in revenues associated with lower recoverable costs under the Company's environmental cost recovery clause. Annually, the Company petitions the Florida PSC for recovery of projected costs, including any true-up amount from prior periods, and approved rates are implemented each January. The recovery provisions include related expenses and a return on average net investment.

Fuel and other cost recovery provisions include fuel expenses, the energy component of purchased power costs, purchased power capacity costs, and the difference between projected and actual costs and revenues related to energy conservation and environmental compliance. Annually, the Company petitions the Florida PSC for recovery of projected fuel and purchased power costs, including any true-up amount from prior periods, and approved rates are implemented each January. The recovery provisions generally equal the related expenses and have no material effect on earnings.

See Note 1 to the financial statements under "Revenues" and Note 3 to the financial statements under "Retail Regulatory Matters" for additional information regarding the Company's retail base rate case and cost recovery clauses, including the Company's fuel cost recovery, purchased power capacity recovery, environmental cost recovery, and energy conservation cost recovery clauses.

Wholesales revenues from sales to non-affiliated utilities were as follows:

	2012	2011	2010
		(in thousands)	
Unit power sales –			
Capacity	**$ 56,379**	$ 52,507	$ 33,482
Energy	**16,520**	44,227	31,379
Total	**72,899**	96,734	64,861
Other power sales –			
Capacity and other	**11,795**	10,717	11,158
Energy	**22,187**	26,104	33,153
Total	**33,982**	36,821	44,311
Total non-affiliated	**$ 106,881**	$ 133,555	$ 109,172

Wholesale revenues from sales to non-affiliates include unit power sales under long-term contracts to other utilities in Florida and Georgia. Wholesale revenues from contracts have both capacity and energy components. Capacity revenues reflect the recovery of fixed costs and a return on investment. Energy is generally sold at variable cost. Wholesale revenues from non-affiliates will vary depending on fuel prices, the market prices of wholesale energy compared to the cost of the Company and the Southern Company system's generation, demand for energy within the Southern Company system's service territory, and the availability of the Southern Company system's generation.

Revenues from unit power sales decreased $23.8 million, or 24.6%, in 2012 primarily due to a 62.6% decrease in energy revenues resulting from a 65.2% decrease in kilowatt-hour (KWH) sales as a result of less energy scheduled by unit power customers due to their use of lower cost generation resources to serve their loads, partially offset by a 7.4% increase in capacity revenues related to higher capacity rates. These contracts include change-in-law provisions that provide for recovery of the environmental costs related to the generating resource. Revenues from other power sales decreased $2.8 million, or 7.7%, in 2012 primarily due to decreased energy revenues resulting from a 16.5% decrease in energy rates, partially offset by a 10.1% increase in capacity revenues related to higher capacity rates. Revenues from unit power sales increased $31.9 million, or 49.1%, in 2011 primarily due to a 56.8% increase in capacity revenues related to higher capacity rates as a result of contracts effective in 2010. The increase in unit power sales was also due to increased energy revenues related to a 31.3% increase in KWH sales. Revenues from other power sales decreased $7.5 million, or 16.9%, in 2011 primarily due to decreased energy revenues related to a 9.6% decrease in KWH sales.

Wholesale revenues from sales to affiliated companies will vary from year to year depending on demand and the availability and cost of generating resources at each company. These affiliated sales and purchases are made in accordance with the Intercompany Interchange Contract (IIC), as approved by the Federal Energy Regulatory Commission (FERC). These transactions do not have a significant impact on earnings since the fuel revenue related to energy sales and the cost of energy purchases are both included in the determination of recoverable fuel costs and are generally offset by revenues collected in the Company's fuel cost recovery clause. In 2012, wholesale revenues from sales to affiliates increased $12.3 million from the prior period primarily due to higher energy revenues related to a 67.6% increase in KWH sales resulting from the availability of the Company's lower priced generation resources to serve affiliate demand, partially offset by a 33.8% decrease in the price of energy in 2012. In 2011, wholesale revenues from sales to affiliates increased $1.3 million from the prior period primarily due to higher energy revenues related to a 7.0% increase in KWH sales resulting from the availability of the Company's lower priced generation resources to serve affiliate demand, partially offset by a 5.2% decrease in the price of energy in 2011.

Other operating revenues decreased $1.7 million, or 2.5%, in 2012 primarily due to a $3.0 million decrease in franchise fees, partially offset by a $2.0 million increase in revenues from other energy services. Other operating revenues increased $4.1 million, or 6.7%, in 2011 primarily due to a $3.4 million increase in revenues from other energy services. Revenues from other energy services did not have a material effect on net income since they were generally offset by associated expenses. Franchise fees have no impact on net income.

Energy Sales

Changes in revenues are influenced heavily by the change in the volume of energy sold from year to year. KWH sales for 2012 and the percent change by year were as follows:

	Total KWHs	**Total KWH Percent Change**		**Weather-Adjusted Percent Change**	
	2012	**2012**	2011	**2012**	2011
	(in millions)				
Residential	**5,054**	**(4.7)%**	(6.1)%	**(0.2)%**	0.5%
Commercial	**3,859**	**(1.4)**	(2.1)	**(0.5)**	—
Industrial	**1,725**	**(4.1)**	6.7	**(4.1)**	6.7
Other	**25**	**(0.6)**	(0.7)	**(0.6)**	(0.7)
Total retail	**10,663**	**(3.4)**	(2.8)	**(0.9)%**	1.3%
Wholesale					
Non-affiliates	**977**	**(51.5)**	20.2		
Affiliates	**4,370**	**67.6**	7.0		
Total wholesale	**5,347**	**15.7**	12.4		
Total energy sales	**16,010**	**2.2 %**	1.2 %		

Changes in retail energy sales are comprised of changes in electricity usage by customers, changes in weather, and changes in the number of customers.

Residential KWH sales and commercial KWH sales decreased in 2012 compared to 2011 primarily due to milder weather in 2012 compared to 2011. Weather-adjusted 2012 KWH sales to residential and commercial customers remained relatively flat as compared to 2011. Residential KWH sales and commercial KWH sales decreased in 2011 compared to 2010 primarily due to closer to normal weather in 2011 compared to 2010. Weather-adjusted 2011 KWH sales to residential and commercial customers remained relatively flat as compared to 2010.

Industrial KWH sales decreased 4.1% in 2012 compared to 2011 primarily due to increased customer co-generation due to the lower cost of natural gas and changes in customer production levels. Industrial KWH sales increased 6.7% in 2011 compared to 2010 primarily resulting from the addition of a new large customer and higher customer load requirements and production levels.

Wholesale KWH sales to non-affiliates decreased 51.5% in 2012 compared to 2011 primarily resulting from less energy scheduled by unit power customers due to their use of lower cost generation resources to serve their loads. Wholesale KWH sales to non-affiliates increased 20.2% in 2011 compared to 2010 primarily resulting from higher KWHs scheduled by unit power customers.

Wholesale KWH sales to affiliates increased 67.6% and 7.0% in 2012 and 2011, respectively, compared to the prior periods primarily resulting from the availability of the Company's lower priced generation resources to serve affiliate demand.

Fuel and Purchased Power Expenses

Fuel costs constitute the single largest expense for the Company. The mix of fuel sources for generation of electricity is determined primarily by demand, the unit cost of fuel consumed, and the availability of generating units. Additionally, the Company purchases a portion of its electricity needs from the wholesale market.

Details of the Company's generation and purchased power were as follows:

	2012	2011	2010
Total generation *(millions of KWHs)*	**9,648**	12,035	13,440
Total purchased power *(millions of KWHs)*	**6,952**	4,349	2,858
Sources of generation *(percent)* –			
Coal	**60**	67	78
Gas	**40**	33	22
Cost of fuel, generated *(cents per net KWH)* –			
Coal	**4.42**	4.97	5.10
Gas	**3.96**	4.06	4.68
Average cost of fuel, generated *(cents per net KWH)*	**4.23**	4.67	5.01
Average cost of purchased power *(cents per net KWH*)*	**3.03**	4.39	5.82

* Average cost of purchased power includes fuel purchased by the Company for tolling agreements where power is generated by the provider.

Total fuel and purchased power expenses were $619.0 million in 2012, a decrease of $133.8 million, or 17.8%, from the prior year costs. The decrease in fuel and purchased power expenses was due to a $129.9 million decrease in the average cost of fuel and purchased power and a $118.2 million decrease related to the volume of KWHs generated. The decrease was partially offset by a $114.3 million increase related to the volume of KWHs purchased. Total fuel and purchased power expenses were $752.8 million in 2011, a decrease of $86.7 million, or 10.3%, from the prior year costs. The decrease in fuel and purchased power expenses was due to a $103.2 million decrease in the average cost of fuel and purchased power and a $70.3 million decrease related to KWHs generated, partially offset by an $86.8 million increase related to KWHs purchased.

From an overall global market perspective, coal prices decreased from levels experienced in 2011 due to lower demand. In the U.S., this decrease was due primarily to relatively lower domestic natural gas prices that contributed to displacement of coal generation by natural gas-fueled generating units. Lower domestic natural gas prices in 2012 were driven by continued robust supplies, including production from shale gas, and only modest increases in overall U.S. consumption.

Fuel and purchased power transactions do not have a significant impact on earnings since energy and capacity expenses are generally offset by energy and capacity revenues through the Company's fuel cost and purchased power capacity recovery clauses. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Fuel Cost Recovery" and "– Purchased Power Capacity Recovery" herein for additional information.

Fuel

Fuel expense was $544.9 million in 2012, a decrease of $117.4 million, or 17.7%, from the prior year costs. The decrease was primarily due to a higher utilization of lower cost natural gas-fired sources, a 2.5% decrease in the average cost of natural gas per KWH generated, and a 19.8% decrease in KWHs generated as a result of displacement of coal-fired generation by energy purchases and lower demand related to milder weather. These decreases were partially offset by a 59.8% increase in KWHs purchased. Fuel expense was $662.3 million in 2011, a decrease of $80.0 million, or 10.8%, from the prior year costs. The decrease was primarily the result of a 13.3% decrease in the average cost of natural gas per KWH generated, a change in the source of generation to be more heavily weighted to lower cost, natural gas-fired generation, and a 10.5% decrease in KWHs generated as a result of lower demand. These decreases were partially offset by a 52.2% increase in KWHs purchased.

Purchased Power – Non-Affiliates

Purchased power expense from non-affiliates was $51.4 million in 2012, an increase of $2.5 million, or 5.2%, from the prior year. The increase was due to a $2.7 million increase in energy costs, partially offset by a $0.2 million decrease in capacity costs. The increase in energy costs was due to an increase in the volume of KWHs purchased, partially offset by a lower average cost per KWH. In 2011, purchased power expense from non-affiliates was $48.9 million, an increase of $7.6 million, or 18.4%, from the prior year. The increase was due to a $7.2 million increase in energy costs and a $0.4 million increase in capacity costs.

Energy purchases from non-affiliates will vary depending on the market prices of wholesale energy as compared to the cost of the Southern Company system's generation, demand for energy within the Southern Company system's service territory, and the availability of the Southern Company system's generation.

Purchased Power – Affiliates

Purchased power expense from affiliates was $22.7 million in 2012, a decrease of $18.9 million, or 45.5%, from the prior year. The decrease was due to a $19.1 million decrease in energy costs, partially offset by a $0.2 million increase in capacity costs. The decrease in energy costs was due to a decrease in the volume of KWHs purchased and a lower cost per KWH purchased. In 2011, purchased power expense from affiliates was $41.6 million, a decrease of $14.3 million, or 25.6%, from the prior year. The decrease was due to decreases of $9.0 million in energy costs and $5.3 million in capacity costs.

Energy purchases from affiliates will vary depending on demand and the availability and cost of generating resources at each company within the Southern Company system. These purchases are made in accordance with the IIC or other contractual agreements, all as approved by the FERC.

Other Operations and Maintenance Expenses

In 2012, other operations and maintenance expenses increased $2.8 million, or 0.9%, compared to the prior year primarily due to increases of $6.2 million in marketing programs and $3.0 million for transmission service related to a third party power purchase agreement (PPA), partially offset by a $6.9 million decrease in routine and planned outage maintenance expense at generation facilities. The increased expense from transmission service did not have a significant impact on earnings since the expense was offset by purchased power capacity revenues through the Company's purchased power capacity recovery clause. The increased expense from marketing programs did not have a significant impact on earnings since the expense was offset by energy conservation revenues through the Company's energy conservation cost recovery clause. In 2011, other operations and maintenance expenses increased $30.7 million, or 11.0%, compared to the prior year primarily due to increases of $13.9 million in routine and planned outage maintenance expense at generation facilities, $3.2 million in other energy services, $10.4 million in labor expense, and $2.1 million in marketing programs. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Cost Recovery Clauses – Purchased Power Capacity Recovery" and "–Energy Conservation Cost Recovery" herein and Note 1 to the financial statements under "Affiliate Transactions" for additional information.

Depreciation and Amortization

Depreciation and amortization increased $11.4 million, or 8.8%, in 2012 compared to the prior year primarily due to the addition of environmental control projects at generation facilities and other net additions to transmission and distribution facilities. Depreciation and amortization increased $8.2 million, or 6.7%, in 2011 compared to the prior year primarily due to the addition of environmental control projects at generation facilities and other net additions to transmission and distribution facilities.

Taxes Other Than Income Taxes

Taxes other than income taxes decreased $3.9 million, or 3.9%, in 2012 compared to the prior year primarily due to a $6.1 million decrease in gross receipts taxes and franchise fees, partially offset by a $1.3 million increase in property taxes and a $0.7 million increase in payroll taxes. Taxes other than income taxes decreased $0.5 million, or 0.5%, in 2011 compared to the prior year primarily due to a $1.1 million decrease in gross receipts taxes, partially offset by a $0.7 million increase in property taxes. Gross receipts taxes and franchise fees have no impact on net income.

Allowance for Funds Used During Construction Equity

Allowance for funds used during construction (AFUDC) equity decreased $4.7 million, or 47.3%, in 2012 compared to the prior year primarily due to an adjustment related to deferred future generation carrying costs and the completion of construction projects related to environmental control projects at generation facilities. AFUDC equity increased $2.7 million, or 37.4%, in 2011 compared to the prior year primarily due to construction of environmental control projects at generation facilities. See Note 1 to the financial statements under "Allowance for Funds Used During Construction" for additional information.

Interest Expense, Net of Amounts Capitalized

Interest expense, net of amounts capitalized increased $2.1 million, or 3.6%, in 2012 compared to the prior year primarily due to increases in long-term debt levels. Interest expense, net of amounts capitalized increased $6.3 million, or 12.0%, in 2011 compared to the prior year primarily due to increases in long-term debt levels resulting from the issuance of additional senior notes in 2011. The increase was partially offset as a result of an increase in capitalization of AFUDC debt related to the construction of environmental control projects.

Income Taxes

Income taxes increased $17.9 million, or 29.3%, in 2012 compared to the prior year primarily due to higher pre-tax earnings, a reduction in the tax benefits associated with a decrease in AFUDC equity, which is non-taxable, and a decrease in state tax credits. Income taxes decreased $10.2 million, or 14.3%, in 2011 compared to the prior year primarily due to lower pre-tax earnings. See Note 5 to the financial statements under "Effective Tax Rate" for additional information.

Effects of Inflation

The Company is subject to rate regulation that is generally based on the recovery of historical and projected costs. The effects of inflation can create an economic loss since the recovery of costs could be in dollars that have less purchasing power. Any adverse effect of inflation on the Company's results of operations has not been substantial in recent years.

FUTURE EARNINGS POTENTIAL

General

The Company operates as a vertically integrated utility providing electricity to retail customers within its traditional service area located in northwest Florida and to wholesale customers in the Southeast. Prices for electricity provided by the Company to retail customers are set by the Florida PSC under cost-based regulatory principles. Prices for wholesale electricity sales, interconnecting transmission lines, and the exchange of electric power are regulated by the FERC. Retail rates and earnings are reviewed and may be adjusted periodically within certain limitations. See ACCOUNTING POLICIES – "Application of Critical Accounting Policies and Estimates – Electric Utility Regulation" herein and Note 3 to the financial statements under "Retail Regulatory Matters" for additional information about regulatory matters.

The results of operations for the past three years are not necessarily indicative of future earnings potential. The level of the Company's future earnings depends on numerous factors that affect the opportunities, challenges, and risks of the Company's business of selling electricity. These factors include the Company's ability to maintain a constructive regulatory environment that continues to allow for the timely recovery of prudently-incurred costs during a time of increasing costs. Future earnings in the near term will depend, in part, upon maintaining energy sales which is subject to a number of factors. These factors include weather, competition, new energy contracts with neighboring utilities, energy conservation practiced by customers, the price of electricity, the price elasticity of demand, and the rate of economic growth or decline in the Company's service territory. Changes in economic conditions impact sales for the Company, and the pace of the economic recovery remains uncertain. The timing and extent of the economic recovery will impact growth and may impact future earnings.

Environmental Matters

Compliance costs related to federal and state environmental statutes and regulations could affect earnings if such costs cannot continue to be fully recovered in rates on a timely basis. Environmental compliance spending over the next several years may differ materially from the amounts estimated. The timing, specific requirements, and estimated costs could change as environmental statutes and regulations are adopted or modified. Further, higher costs that are recovered through regulated rates could contribute to reduced demand for electricity, which could negatively affect results of operations, cash flows, and financial condition. See Note 3 to the financial statements under "Environmental Matters" for additional information.

New Source Review Actions

In 1999, the Environmental Protection Agency (EPA) brought a civil action in the U.S. District Court for the Northern District of Georgia against certain Southern Company subsidiaries, including Alabama Power Company (Alabama Power) and Georgia Power Company (Georgia Power), alleging that these subsidiaries had violated the New Source Review (NSR) provisions of the Clean Air Act and related state laws at certain coal-fired generating facilities. The EPA alleged NSR violations at five coal-fired generating facilities operated by Alabama Power and three coal-fired generating facilities operated by Georgia Power, including a unit co-owned by the Company. The civil action sought penalties and injunctive relief, including an order requiring installation of the best available control technology at the affected units. These actions were filed concurrently with the issuance of notices of violation of the NSR provisions to the Company with respect to the Company's Plant Crist. The case against Georgia Power

(including claims related to the unit co-owned by the Company) was administratively closed in 2001 and has not been reopened. After Alabama Power was dismissed from the original action, the EPA filed a separate action in 2001 against Alabama Power in the U.S. District Court for the Northern District of Alabama.

The Company believes it complied with applicable laws and regulations in effect at the time the work in question took place. The Clean Air Act authorizes maximum civil penalties of $25,000 to $37,500 per day, per violation, depending on the date of the alleged violation. An adverse outcome could require substantial capital expenditures that cannot be determined at this time and could possibly require payment of substantial penalties. Such expenditures could affect future results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates. The ultimate outcome of this matter cannot be determined at this time.

Climate Change Litigation

Kivalina Case

In 2008, the Native Village of Kivalina and the City of Kivalina filed a lawsuit in the U.S. District Court for the Northern District of California against several electric utilities (including Southern Company), several oil companies, and a coal company. The plaintiffs allege that the village is being destroyed by erosion allegedly caused by global warming that the plaintiffs attribute to emissions of greenhouse gases by the defendants. The plaintiffs assert claims for public and private nuisance and contend that some of the defendants (including Southern Company) acted in concert and are therefore jointly and severally liable for the plaintiffs' damages. The suit seeks damages for lost property values and for the cost of relocating the village, which is alleged to be $95 million to $400 million. In 2009, the U.S. District Court for the Northern District of California granted the defendants' motions to dismiss the case. On September 21, 2012, the U.S. Court of Appeals for the Ninth Circuit upheld the U.S. District Court for the Northern District of California's dismissal of the case. On November 27, 2012, the U.S. Court of Appeals for the Ninth Circuit denied the plaintiffs' request for review of the decision. On February 25, 2013, the plaintiffs filed a petition for writ of certiorari with the U.S. Supreme Court. Southern Company believes that these claims are without merit. The ultimate outcome of this matter cannot be determined at this time.

Hurricane Katrina Case

In 2005, immediately following Hurricane Katrina, a lawsuit was filed in the U.S. District Court for the Southern District of Mississippi by Ned Comer on behalf of Mississippi residents seeking recovery for property damage and personal injuries caused by Hurricane Katrina. In 2006, the plaintiffs amended the complaint to include Southern Company and many other electric utilities, oil companies, chemical companies, and coal producers. The plaintiffs allege that the defendants contributed to climate change, which contributed to the intensity of Hurricane Katrina. In 2007, the U.S. District Court for the Southern District of Mississippi dismissed the case. On appeal to the U.S. Court of Appeals for the Fifth Circuit, a three-judge panel reversed the U.S. District Court for the Southern District of Mississippi, holding that the case could proceed, but on rehearing, the full U.S. Court of Appeals for the Fifth Circuit dismissed the plaintiffs' appeal, resulting in reinstatement of the decision of the U.S. District Court for the Southern District of Mississippi in favor of the defendants. In May 2011, the plaintiffs filed an amended version of their class action complaint, arguing that the earlier dismissal was on procedural grounds and under Mississippi law the plaintiffs have a right to re-file. The amended complaint was also filed against numerous chemical, coal, oil, and utility companies, including the Company. On March 20, 2012, the U.S. District Court for the Southern District of Mississippi dismissed the plaintiffs' amended complaint. On April 16, 2012, the plaintiffs appealed the case to the U.S. Court of Appeals for the Fifth Circuit. The Company believes that these claims are without merit. The ultimate outcome of this matter cannot be determined at this time.

Environmental Statutes and Regulations

General

The Company's operations are subject to extensive regulation by state and federal environmental agencies under a variety of statutes and regulations governing environmental media, including air, water, and land resources. Applicable statutes include the Clean Air Act; the Clean Water Act; the Comprehensive Environmental Response, Compensation, and Liability Act; the Resource Conservation and Recovery Act; the Toxic Substances Control Act; the Emergency Planning & Community Right-to-Know Act; the Endangered Species Act; and related federal and state regulations. Compliance with these environmental requirements involves significant capital and operating costs, a major portion of which is expected to be recovered through existing ratemaking provisions. Through 2012, the Company had invested approximately $1.4 billion in environmental capital retrofit projects to comply with these requirements, with annual totals of approximately $70 million, $141 million, and $136 million for 2012, 2011, and 2010, respectively. The Company expects that base level capital expenditures to comply with existing statutes and regulations, including capital expenditures and compliance costs associated with the EPA's final Mercury and Air Toxics Standards (MATS) rule, will be a total of approximately $644 million from 2013 through 2015, with annual totals of approximately $158 million, $319 million, and $167 million for 2013, 2014, and 2015, respectively.

The Company continues to monitor the development of the EPA's proposed water and coal combustion byproducts rules and to evaluate compliance options. See FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" herein for the Company's anticipated incremental compliance costs related to the proposed water and coal combustion byproducts rules for 2013 through 2015. The ultimate capital expenditures and compliance costs with respect to these proposed rules, including additional expenditures required after 2015, will be dependent on the requirements of the final rules and regulations adopted by the EPA and the outcome of any legal challenges to these rules. See "Water Quality" and "Coal Combustion Byproducts" herein for additional information.

The Company's ultimate environmental compliance strategy, including potential unit retirement and replacement decisions and future environmental capital expenditures will be affected by the final requirements of new or revised environmental regulations and regulations relating to global climate change that are promulgated, including the proposed environmental regulations described below; the outcome of any legal challenges to the environmental rules; the cost, availability, and existing inventory of emissions allowances; and the Company's fuel mix. Compliance costs may arise from existing unit retirements, installation of additional environmental controls, upgrades to the transmission system, and adding or changing fuel sources for certain existing units. The ultimate outcome of these matters cannot be determined at this time.

The State of Florida has statutory provisions that allow a utility to petition the Florida PSC for recovery of prudent environmental compliance costs that are not being recovered through base rates or any other recovery mechanism. The environmental cost recovery mechanism in Florida is discussed in Note 3 to the financial statements under "Retail Regulatory Matters – Environmental Cost Recovery." Substantially all of the costs for the Clean Air Act and other new environmental legislation discussed below are expected to be recovered through the environmental cost recovery clause.

Compliance with any new federal or state legislation or regulations relating to air quality, water, coal combustion byproducts, global climate change, or other environmental and health concerns could significantly affect the Company. Although new or revised environmental legislation or regulations could affect many areas of the Company's operations, the full impact of any such changes cannot be determined at this time. Additionally, many of the Company's commercial and industrial customers may also be affected by existing and future environmental requirements, which for some may have the potential to ultimately affect their demand for electricity.

Air Quality

Compliance with the Clean Air Act and resulting regulations has been and will continue to be a significant focus for the Company. Since 1990, the Company has spent approximately $1.1 billion in reducing and monitoring emissions pursuant to the Clean Air Act. Additional controls are currently planned or under consideration to further reduce air emissions, maintain compliance with existing regulations, and meet new requirements.

The EPA regulates ground level ozone concentrations through implementation of an eight-hour ozone air quality standard. In 2008, the EPA adopted a more stringent eight-hour ozone National Ambient Air Quality Standard, which it began to implement in September 2011. On May 21, 2012, the EPA published its final determination of nonattainment areas based on the 2008 eight-hour ozone air quality standards. No areas within the Company's service territory were determined to be in nonattainment of this standard.

The EPA regulates fine particulate matter concentrations on an annual and 24-hour average basis. All areas within the Company's service territory have achieved attainment with the 1997 and 2006 particulate matter National Ambient Air Quality Standards. On January 15, 2013, the EPA published a final rule that increases the stringency of the annual fine particulate matter standard. The new standard could result in the designation of new nonattainment areas within the Company's service territory.

Final revisions to the National Ambient Air Quality Standard for sulfur dioxide (SO_2), including the establishment of a new one-hour standard, became effective in 2010. The EPA plans to issue area designations under this new standard in June 2013, and areas within the Company's service territory could ultimately be designated as nonattainment. Implementation of the revised SO_2 standard could require additional reductions in SO_2 emissions and increased compliance and operational costs.

Revisions to the National Ambient Air Quality Standard for nitrogen dioxide (NO_2), which established a new one-hour standard, became effective in 2010. On February 29, 2012, the new NO_2 standard became effective. The EPA designated the entire country as "unclassifiable/attainment" under the new standard, with no nonattainment areas designated. However, the new NO_2 standard could result in significant additional compliance and operational costs for units that require new source permitting.

The Company's service territory is subject to the requirements of the Clean Air Interstate Rule (CAIR), which calls for phased reductions in SO_2 and nitrogen oxide (NO_x) emissions from power plants in 28 eastern states. In 2008, the U.S. Court of Appeals for the District of Columbia Circuit issued decisions invalidating CAIR, but left CAIR compliance requirements in place while the EPA developed a new rule. In August 2011, the EPA adopted the Cross State Air Pollution Rule (CSAPR) to replace CAIR effective January 1, 2012. However, in December 2011, the U. S. Court of Appeals for the District of Columbia Circuit stayed the rule and, on August 21, 2012, vacated CSAPR in its entirety and directed the EPA to continue to administer CAIR pending the EPA's development of a valid replacement. On January 24, 2013, the U.S. Court of Appeals for the District of Columbia Circuit denied requests by the EPA and other parties for rehearing.

The EPA finalized the Clean Air Visibility Rule (CAVR) in 2005, with a goal of restoring natural visibility conditions in certain areas (primarily national parks and wilderness areas) by 2064. The rule involves the application of best available retrofit technology (BART) to certain sources built between 1962 and 1977 and any additional emissions reductions necessary for each designated area to achieve reasonable progress toward the natural visibility conditions goal by 2018 and for each 10-year period thereafter. In 2005, the EPA determined that compliance with CAIR satisfies BART obligations under CAVR, but, on June 7, 2012, the EPA issued a final rule replacing CAIR with CSAPR as an alternative means of satisfying BART obligations. The vacatur of CSAPR creates additional uncertainty with respect to whether additional controls may be required for CAVR and BART compliance.

On February 16, 2012, the EPA published the final MATS rule, which imposes stringent emissions limits for acid gases, mercury, and particulate matter on coal- and oil-fired electric utility steam generating units. Compliance for existing sources is required by April 16, 2015, unless a one-year compliance extension is granted by the state or local air permitting agency. Mississippi Power Company (Mississippi Power) has received this one-year extension for Plant Daniel to April 16, 2016.

Numerous petitions for administrative reconsideration of the MATS rule, including a petition by the Company, have been filed with the EPA. On November 30, 2012, the EPA proposed a reconsideration of certain new source and startup/shutdown issues. The EPA plans to complete its reconsideration rulemaking by March 2013. Challenges to the final rule have also been filed in the U.S. District Court for the District of Columbia by numerous states, environmental organizations, industry groups, and others.

On August 29, 2012, the EPA published proposed revisions to the New Source Performance Standard (NSPS) for Stationary Combustion Turbines (CTs). If finalized as proposed, the revisions would apply the NSPS to all new, reconstructed, and modified CTs (including CTs at combined cycle units), during all periods of operation, including startup and shutdown, and alter the criteria for determining when an existing CT has been reconstructed.

On February 12, 2013, the EPA proposed a rule that would require certain states to revise the provisions of their State Implementation Plans (SIPs) relating to the regulation of excess emissions at industrial facilities, including fossil fuel-fired generating facilities, during periods of startup, shut-down, or malfunction (SSM). The EPA proposes a determination that the SSM provisions in the SIPs for 36 states (including Florida, Georgia, and Mississippi) do not meet the requirements of the Clean Air Act and must be revised within 18 months of the date on which the EPA publishes the final rule. If finalized as proposed, this new requirement could result in significant additional compliance and operational costs.

The Company has developed and continually updates a comprehensive environmental compliance strategy to assess compliance obligations associated with the existing and new environmental requirements discussed above. The impacts of the eight-hour ozone, fine particulate matter, SO_2 and NO_2 standards, CAIR and any future replacement rule, CAVR, the MATS rule, the NSPS for CTs, and the SSM rule on the Company cannot be determined at this time and will depend on the specific provisions of recently finalized and future rules, the resolution of pending and future legal challenges, and the development and implementation

of rules at the state level. These regulations could result in significant additional compliance costs that could affect future unit retirement and replacement decisions and results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates. Further, higher costs that are recovered through regulated rates could contribute to reduced demand for electricity, which could negatively impact results of operations, cash flows, and financial condition. In addition, certain units in the State of Georgia, including Plant Scherer Unit 3, which is co-owned by the Company, are required to install specific emissions controls according to a schedule set forth in the state's Multi-Pollutant Rule, which is designed to reduce emissions of SO_2, NO_x, and mercury.

See Note 3 to the financial statements under "Retail Regulatory Matters – Environmental Cost Recovery" for discussion of the State of Florida's statutory provisions on environmental cost recovery.

Water Quality

In April 2011, the EPA published a proposed rule that establishes standards for reducing effects on fish and other aquatic life caused by cooling water intake structures at existing power plants and manufacturing facilities. The rule also addresses cooling water intake structures for new units at existing facilities. Compliance with the proposed rule could require changes to existing cooling water intake structures at certain of the Company's generating facilities, and new generating units constructed at existing plants would be required to install closed cycle cooling towers. The EPA has entered into an amended settlement agreement to extend the deadline for issuing a final rule until June 27, 2013. If finalized as proposed, some of the Company's facilities may be subject to significant additional capital expenditures and compliance costs that could affect future unit retirement and replacement decisions. Also, results of operations, cash flows, and financial condition could be significantly impacted if such costs are not recovered through regulated rates. The ultimate outcome of this rulemaking will depend on the final rule and the outcome of any legal challenges and cannot be determined at this time.

The EPA has announced its determination that revision of the current effluent guidelines for steam electric power plants is warranted and has stated that it intends to propose such revisions by April 2013 and finalize the revisions by May 2014. New advanced wastewater treatment requirements are expected and may result in the installation of additional controls on certain of the Company's facilities, which could result in significant additional capital expenditures and compliance costs that could affect future unit retirement and replacement decisions. The impact of the revised guidelines will depend on the specific technology requirements of the final rule and, therefore, cannot be determined at this time.

In addition, the State of Florida is finalizing numeric nutrient water quality standards to limit the amount of nitrogen and phosphorous allowed in state waters. The impact of these standards will depend on the specific requirements of the final rule and cannot be determined at this time. See FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" for additional information regarding estimated compliance costs for 2013 through 2015. See also Note 3 to the financial statements under "Retail Regulatory Matters – Environmental Cost Recovery" for discussion of the State of Florida's statutory provisions on environmental cost recovery.

Coal Combustion Byproducts

The Company currently operates three electric generating plants in Florida and is part owner of units at generating plants located in Mississippi and Georgia operated by the respective unit's co-owner with on-site coal combustion byproducts storage facilities. In addition to on-site storage, the Company sells a portion of its coal combustion byproducts to third parties for beneficial reuse. Historically, individual states have regulated coal combustion byproducts and the States of Florida, Georgia, and Mississippi each has its own regulatory parameters. The Company has a routine and robust inspection program in place to ensure the integrity of its coal ash surface impoundments and compliance with applicable regulations.

The EPA continues to evaluate the regulatory program for coal combustion byproducts, including coal ash and gypsum, under federal solid and hazardous waste laws. In 2010, the EPA published a proposed rule that requested comments on two potential regulatory options for the management and disposal of coal combustion byproducts: regulation as a solid waste or regulation as if the materials technically constituted a hazardous waste. Adoption of either option could require closure of, or significant change to, existing storage facilities and construction of lined landfills, as well as additional waste management and groundwater monitoring requirements. Under both options, the EPA proposes to exempt the beneficial reuse of coal combustion byproducts from regulation; however, a hazardous or other designation indicative of heightened risk could limit or eliminate beneficial reuse options. Environmental groups and other parties have filed lawsuits in the U.S. District Court for the District of Columbia seeking to require the EPA to complete its rulemaking process and issue final regulations pertaining to the regulation of coal combustion byproducts.

While the ultimate outcome of this matter cannot be determined at this time and will depend on the final form of any rules adopted and the outcome of any legal challenges, additional regulation of coal combustion byproducts could have a material impact on the generation, management, beneficial use, and disposal of such byproducts. Any material changes are likely to result in substantial additional compliance, operational, and capital costs that could affect future unit retirement and replacement decisions. Moreover, the Company could incur additional material asset retirement obligations with respect to closing existing storage facilities. The Company's results of operations, cash flows, and financial condition could be significantly impacted if such costs are not recovered through regulated rates. Further, higher costs that are recovered through regulated rates could contribute to reduced demand for electricity, which could negatively impact results of operations, cash flows, and financial condition. See FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" herein for additional information regarding estimated compliance costs for 2013 through 2015. See also Note 3 to the Financial Statements under "Retail Regulatory Matters – Environmental Cost Recovery" for discussion of the State of Florida's statutory provisions on environmental cost recovery.

Environmental Remediation

The Company must comply with other environmental laws and regulations that cover the handling and disposal of waste and releases of hazardous substances. Under these various laws and regulations, the Company may also incur substantial costs to clean up properties. The Company conducts studies to determine the extent of any required cleanup and has recognized in its financial statements the costs to clean up known impacted sites. Included in this amount are costs associated with remediation of the Company's substation sites. These projects have been approved by the Florida PSC for recovery through the environmental cost recovery clause; therefore, there is no impact to the Company's net income as a result of these liabilities. The Company may be liable for some or all required cleanup costs for additional sites that may require environmental remediation. See Note 3 to the financial statements under "Environmental Matters – Environmental Remediation" for additional information.

Global Climate Issues

The EPA currently regulates greenhouse gases under the Prevention of Significant Deterioration and Title V operating permit programs of the Clean Air Act. In addition, over the past several years, the U.S. Congress has considered many proposals to reduce greenhouse gas emissions, mandate renewable or clean energy, and impose energy efficiency standards. Such proposals are expected to continue to be considered by the U.S. Congress. International climate change negotiations under the United Nations Framework Convention on Climate Change are also continuing.

On April 13, 2012, the EPA published proposed regulations to establish standards of performance for greenhouse gas emissions from new fossil fuel steam electric generating units. The EPA has also announced plans to develop federal guidelines for states to establish greenhouse gas emissions performance standards for existing sources. The impact of this rulemaking will depend on the scope and specific requirements of the final rule and the outcome of any legal challenges and, therefore, cannot be determined at this time.

Although the outcome of federal, state, and international initiatives cannot be determined at this time, additional restrictions on the Company's greenhouse gas emissions or requirements relating to renewable energy or energy efficiency at the federal or state level could result in significant additional compliance costs, including capital expenditures. These costs could affect future unit retirement and replacement decisions and could result in the retirement of a significant number of coal-fired generating units. See Item 1 – BUSINESS – "Rate Matters – Integrated Resource Planning" of the Form 10-K for additional information.

Also, additional compliance costs and costs related to unit retirements could affect results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates. Further, higher costs that are recovered through regulated rates could contribute to reduced demand for electricity, which could negatively impact results of operations, cash flows, and financial condition. See Note 3 to the financial statements under "Retail Regulatory Matters – Environmental Cost Recovery" for discussion of the State of Florida's statutory provisions on environmental cost recovery.

The EPA's greenhouse gas reporting rule requires annual reporting of carbon dioxide equivalent emissions in metric tons for a company's operational control of facilities. Based on ownership or financial control of facilities, the Company reported 2011 greenhouse gas emissions of approximately 11 million metric tons of carbon dioxide equivalent. The preliminary estimate of the Company's 2012 greenhouse gas emissions on the same basis is approximately 8 million metric tons of carbon dioxide equivalent. The level of greenhouse gas emissions from year to year will depend on the level of generation and mix of fuel sources, which is determined primarily by demand, the unit cost of fuel consumed, and the availability of generating units.

PSC Matters

The Company's rates and charges for service to retail customers are subject to the regulatory oversight of the Florida PSC. The Company's rates are a combination of base rates and several separate cost recovery clauses for specific categories of costs. These

separate cost recovery clauses address such items as fuel and purchased energy costs, purchased power capacity costs, energy conservation and demand side management programs, and the costs of compliance with environmental laws and regulations. Costs not addressed through one of the specific cost recovery clauses are recovered through the Company's base rates.

Retail Base Rate Case

On March 12, 2012, the Florida PSC approved an increase in retail base rates and charges of $64 million effective April 11, 2012. The amount of the increase includes the previously approved $38.5 million interim retail rate increase implemented in September 2011. The Florida PSC's decision on the amount of the increase also included a determination that none of the base rate revenues collected on an interim basis would be refunded. The Company's authorized retail ROE is a range of 9.25% to 11.25% with new retail base rates set at the midpoint retail ROE of 10.25%. In addition, the Florida PSC also approved a step increase to the Company's retail base rates and charges of $4 million effective in January 2013.

Cost Recovery Clauses

On November 5, 2012, the Florida PSC approved the Company's annual rate clause requests for its fuel, purchased power capacity, conservation, and environmental compliance cost recovery factors for 2013. The net effect of the approved changes is a 1.9% rate increase for residential customers using 1,000 KWHs per month.

Revenues for all cost recovery clauses, as recorded on the financial statements, are adjusted for differences in actual recoverable costs and amounts billed in current regulated rates. Accordingly, changes in the billing factor for fuel and purchased power will have no significant effect on the Company's revenues or net income, but will affect annual cash flow. The recovery provisions for environmental compliance and energy conservation include related expenses and a return on net average investment. See Notes 1 and 3 to the financial statements under "Revenues" and "Retail Regulatory Matters" respectively, for additional information.

Fuel Cost Recovery

The Company has established fuel cost recovery rates as approved by the Florida PSC. If, at any time during the year, the projected year-end fuel cost over or under recovery balance exceeds 10% of the projected fuel revenue applicable for the period, the Company is required to notify the Florida PSC and indicate if an adjustment to the fuel cost recovery factor is being requested. On February 14, 2012, the Florida PSC approved a reduction to the fuel cost recovery factors starting in March 2012. The effect of the approved change was a 2.7% decrease for residential customers using 1,000 KWHs per month. On June 19, 2012, the Florida PSC approved an additional decrease in the Company's fuel rates lowering the 1,000 KWH residential bill 7.8% to reduce annual billings by approximately $58.8 million effective July 2, 2012.

The increase in the fuel cost over recovered balance during 2012 was primarily due to lower than expected fuel costs and purchased power energy expenses. At December 31, 2012 and 2011, the over recovered fuel balance was approximately $17.1 million and $9.9 million, respectively, which is included in other regulatory liabilities, current in the balance sheets. See Note 1 to the financial statements under "Fuel Costs" and "Fuel Inventory" for additional information.

Purchased Power Capacity Recovery

The Company has established purchased power capacity recovery cost rates as approved by the Florida PSC. If the projected year-end purchased power capacity cost over or under recovery balance exceeds 10% of the projected purchased power capacity revenue applicable for the period, the Company is required to notify the Florida PSC and indicate if an adjustment to the purchased power capacity cost recovery factor is being requested.

At December 31, 2012, the Company had an under recovered purchased power capacity balance of approximately $0.8 million, which is included in under recovered regulatory clause revenues in the balance sheets. At December 31, 2011, the Company had an over recovered purchased power capacity balance of approximately $8.0 million, which is included in other regulatory liabilities, current in the balance sheets. See Note 7 to the financial statements under "Fuel and Purchased Power Commitments" for additional information.

Environmental Cost Recovery

The Florida Legislature adopted legislation for an environmental cost recovery clause, which allows an electric utility to petition the Florida PSC for recovery of prudent environmental compliance costs that are not being recovered through base rates or any other recovery mechanism. Such environmental costs include operations and maintenance expenses, emissions allowance expense, depreciation, and a return on net average investment. This legislation also allows recovery of costs incurred as a result of an agreement between the Company and the Florida Department of Environmental Protection for the purpose of ensuring compliance with ozone ambient air quality standards adopted by the EPA.

In 2007, the Florida PSC voted to approve a stipulation among the Company, the Office of Public Counsel, and the Florida Industrial Power Users Group regarding the Company's plan for complying with certain federal and state regulations addressing air quality. The Company's environmental compliance plan as filed in 2007 contemplated implementation of specific projects identified in the plan from 2007 through 2018. The stipulation covers all elements of the original plan that were committed for implementation at the time of the stipulation. The Florida PSC's approval of the stipulation also required the Company to file annual updates to the plan and outlined a process for approval of additional elements in the plan when they became committed projects. In the 2010 update filing, the Company identified several elements of the updated plan that the Company had decided to implement. Following the process outlined in the original approved stipulation, these additional projects were approved by the Florida PSC later in 2010. The Florida PSC acknowledged that the costs of the approved projects associated with the Company's CAIR and CAVR compliance plans are eligible for recovery through the environmental cost recovery clause.

Annually, the Company seeks recovery of projected costs including any true-up amounts from prior periods. At December 31, 2012, the under recovered environmental balance was approximately $1.9 million, which is included in under recovered regulatory clause revenues in the balance sheets. At December 31, 2011, the over recovered environmental balance was approximately $10.0 million, which is included in other regulatory liabilities, current in the balance sheets. See FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" herein for additional information.

On April 3, 2012, the Mississippi PSC approved Mississippi Power's request for a certificate of public convenience and necessity to construct a flue gas desulfurization system (scrubber) on Plant Daniel Units 1 and 2. On May 3, 2012, the Sierra Club filed a notice of appeal of the order with the Chancery Court of Harrison County, Mississippi. These units are jointly owned by Mississippi Power and the Company, with 50% ownership each. The estimated total cost of the project is approximately $660 million, excluding AFUDC, and it is scheduled for completion in December 2015. The Company's portion of the cost is expected to be recovered through the environmental cost recovery clause. The ultimate outcome of this matter cannot be determined at this time.

Energy Conservation Cost Recovery

Every five years, the Florida PSC establishes new numeric conservation goals covering a 10-year period for utilities to reduce annual energy and seasonal peak demand using demand-side management (DSM) programs. After the goals are established, utilities develop plans and programs to meet the approved goals. The costs for these programs are recovered through rates established annually in the energy conservation cost recovery (ECCR) clause.

The most recent goal setting process established new DSM goals for the period 2010 through 2019. The new goals are significantly higher than the goals established in the previous five-year cycle due to a change in the cost-effectiveness test on which the Florida PSC relies to set the goals. The DSM program standards were approved in April 2011, which allow the Company to implement its DSM programs designed to meet the new goals. Several of these new programs were implemented in June 2011 and the costs related to these programs are reflected in the 2012 ECCR factor approved by the Florida PSC. Higher cost recovery rates and achievement of the new DSM goals may result in reduced sales of electricity which could negatively impact results of operations, cash flows, and financial condition if base rates cannot be adjusted on a timely basis.

See BUSINESS under "Rate Matters – Integrated Resource Planning – Gulf Power" in Item 1 for a discussion of the Company's 10-year site plan filed on an annual basis with the Florida PSC.

At December 31, 2012 and 2011, the under recovered energy conservation balance was approximately $0.8 million and $3.1 million, respectively, which is included in under recovered regulatory clause revenues in the balance sheets.

Income Tax Matters

Bonus Depreciation

In 2010, the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010 (Tax Relief Act) was signed into law. Major tax incentives in the Tax Relief Act include 100% bonus depreciation for property placed in service after September 8, 2010 and through 2011 (and for certain long-term production-period projects placed in service in 2012) and 50% bonus depreciation for property placed in service in 2012 (and for certain long-term production-period projects to be placed in service in 2013), which will have a positive impact on the future cash flows of the Company through 2013.

On January 2, 2013, the American Taxpayer Relief Act of 2012 (ATRA) was signed into law. The ATRA retroactively extended several tax credits through 2013 and extended 50% bonus depreciation for property to be placed in service in 2013 (and for certain long-term production-period projects to be placed in service in 2014). The extension of 50% bonus depreciation will have a positive impact on the future cash flows of the Company through 2014.

Consequently, the Company's positive cash flow benefit is estimated to be between $30 million and $35 million in 2013.

Other Matters

The Company is involved in various other matters being litigated and regulatory matters that could affect future earnings. In addition, the Company is subject to certain claims and legal actions arising in the ordinary course of business. The Company's business activities are subject to extensive governmental regulation related to public health and the environment, such as regulation of air emissions and water discharges. Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements, such as air quality and water standards, has increased generally throughout the U.S. In particular, personal injury, property damage, and other claims for damages alleged to have been caused by carbon dioxide and other emissions, coal combustion byproducts, and alleged exposure to hazardous materials, and/or requests for injunctive relief in connection with such matters, have become more frequent. The ultimate outcome of such pending or potential litigation against the Company cannot be predicted at this time; however, for current proceedings not specifically reported herein or in Note 3 to the financial statements, management does not anticipate that the ultimate liabilities, if any, arising from such current proceedings would have a material effect on the Company's financial statements. See Note 3 to the financial statements for a discussion of various other contingencies, regulatory matters, and other matters being litigated which may affect future earnings potential.

ACCOUNTING POLICIES

Application of Critical Accounting Policies and Estimates

The Company prepares its financial statements in accordance with generally accepted accounting principles (GAAP). Significant accounting policies are described in Note 1 to the financial statements. In the application of these policies, certain estimates are made that may have a material impact on the Company's results of operations and related disclosures. Different assumptions and measurements could produce estimates that are significantly different from those recorded in the financial statements. Senior management has reviewed and discussed the following critical accounting policies and estimates with the Audit Committee of Southern Company's Board of Directors.

Electric Utility Regulation

The Company is subject to retail regulation by the Florida PSC. The Florida PSC sets the rates the Company is permitted to charge customers based on allowable costs. The Company is also subject to cost based regulation by the FERC with respect to wholesale transmission rates. As a result, the Company applies accounting standards which require the financial statements to reflect the effects of rate regulation. Through the ratemaking process, the regulators may require the inclusion of costs or revenues in periods different than when they would be recognized by a non-regulated company. This treatment may result in the deferral of expenses and the recording of related regulatory assets based on anticipated future recovery through rates or the deferral of gains or creation of liabilities and the recording of related regulatory liabilities. The application of the accounting standards has a further effect on the Company's financial statements as a result of the estimates of allowable costs used in the ratemaking process. These estimates may differ from those actually incurred by the Company; therefore, the accounting estimates inherent in specific costs such as depreciation and pension and postretirement benefits have less of a direct impact on the Company's results of operations and financial condition than they would on a non-regulated company.

As reflected in Note 1 to the financial statements, significant regulatory assets and liabilities have been recorded. Management reviews the ultimate recoverability of these regulatory assets and any requirement to refund these regulatory liabilities based on applicable regulatory guidelines and GAAP. However, adverse legislative, judicial, or regulatory actions could materially impact the amounts of such regulatory assets and liabilities and could adversely impact the Company's financial statements.

Contingent Obligations

The Company is subject to a number of federal and state laws and regulations, as well as other factors and conditions that subject it to environmental, litigation, income tax, and other risks. See FUTURE EARNINGS POTENTIAL herein and Note 3 to the financial statements for more information regarding certain of these contingencies. The Company periodically evaluates its exposure to such risks and, in accordance with GAAP, records reserves for those matters where a non-tax-related loss is considered probable and reasonably estimable and records a tax asset or liability if it is more likely than not that a tax position will be sustained. The adequacy of reserves can be significantly affected by external events or conditions that can be unpredictable; thus, the ultimate outcome of such matters could materially affect the Company's financial statements.

Unbilled Revenues

In November 2012, the Company began using automated meter readings to measure unbilled KWH sales for energy delivered through month-end. As of December 31, 2012, measured unbilled KWH sales represented approximately 90% of total unbilled KWH sales. Increased usage of actual data to compute unbilled revenues reduces the impact that estimates could have on the Company's results of operations; therefore, the Company no longer considers unbilled revenue a critical accounting estimate.

Pension and Other Postretirement Benefits

The Company's calculation of pension and other postretirement benefits expense is dependent on a number of assumptions. These assumptions include discount rates, healthcare cost trend rates, expected long-term return on plan assets, mortality rates, expected salary and wage increases, and other factors. Components of pension and other postretirement benefits expense include interest and service cost on the pension and other postretirement benefit plans, expected return on plan assets and amortization of certain unrecognized costs and obligations. Actual results that differ from the assumptions utilized are accumulated and amortized over future periods and, therefore, generally affect recognized expense and the recorded obligation in future periods. While the Company believes that the assumptions used are appropriate, differences in actual experience or significant changes in assumptions would affect its pension and other postretirement benefits costs and obligations.

Key elements in determining the Company's pension and other postretirement benefit expense in accordance with GAAP are the expected long-term return on plan assets and the discount rate used to measure the benefit plan obligations and the periodic benefit plan expense for future periods. The expected long-term return on postretirement benefit plan assets is based on the Company's investment strategy, historical experience, and expectations for long-term rates of return that consider external actuarial advice. The Company determines the long-term return on plan assets by applying the long-term rate of expected returns on various asset classes to the Company's target asset allocation. The Company discounts the future cash flows related to its postretirement benefit plans using a single-point discount rate developed from the weighted average of market-observed yields for high quality fixed income securities with maturities that correspond to expected benefit payments.

A 25 basis point change in any significant assumption (discount rate, salaries, or long-term return on plan assets) would result in a $1.3 million or less change in total annual benefit expense and an $18 million or less change in projected obligations.

FINANCIAL CONDITION AND LIQUIDITY

Overview

The Company's financial condition remained stable at December 31, 2012. The Company's cash requirements primarily consist of funding ongoing operations, common stock dividends, capital expenditures, and debt maturities. Capital expenditures and other investing activities include investments to meet projected long-term demand requirements, to comply with environmental regulations, and for restoration following major storms. Operating cash flows provide a substantial portion of the Company's cash needs. For the three-year period from 2013 through 2015, the Company's projected common stock dividends, capital expenditures, and debt maturities are expected to exceed operating cash flows. Projected capital expenditures in that period are primarily to add environmental equipment for existing generating units and to expand and improve transmission and distribution facilities. The Company plans to finance future cash needs in excess of its operating cash flows primarily through debt and equity issuances. The Company intends to continue to monitor its access to short-term and long-term capital markets as well as its bank credit arrangements to meet future capital and liquidity needs. See "Sources of Capital," "Financing Activities," and "Capital Requirements and Contractual Obligations" herein for additional information.

The Company's investments in the qualified pension plan increased in value as of December 31, 2012 as compared to December 31, 2011. In December 2012, the Company contributed $13.4 million to the qualified pension plan.

Net cash provided from operating activities totaled $419.2 million in 2012, an increase of $43.0 million from 2011, primarily due to an increase in deferred income taxes primarily related to bonus depreciation, partially offset by decreases in the cash provided from prepaid income taxes, fossil fuel stock, and the recovery of fuel costs. Net cash provided from operating activities totaled $376.2 million in 2011, an increase of $108.4 million from 2010, primarily due to increases in the recovery of fuel costs and prepaid income taxes, primarily due to bonus depreciation.

Net cash used for investing activities totaled $348.6 million, $343.5 million, and $308.4 million for 2012, 2011, and 2010, respectively. The changes in cash used for investing activities were primarily due to gross property additions to utility plant of $325.2 million, $337.8 million, and $285.4 million for 2012, 2011, and 2010, respectively. Funds for the Company's property additions were provided by operating activities, capital contributions, and other financing activities.

Net cash used for financing activities totaled $55.8 million and $31.8 million in 2012 and 2011, respectively. Net cash provided from financing activities was $48.4 million in 2010. The 2012 and 2011 decreases in cash from financing activities were primarily due to short-term debt payments, long-term debt redemptions, and payment of common stock dividends, partially offset

by common stock and long-term debt issuances. Fluctuations in cash flow from financing activities vary from year to year based on capital needs and the maturity or redemption of securities.

Significant balance sheet changes in 2012 include an increase of $219.5 million in property, plant, and equipment, primarily due to the addition of environmental control projects at generation facilities, an increase of $190.0 million in accumulated deferred income taxes, primarily related to bonus depreciation, an increase in common stock, without par value due to the issuance of common stock to Southern Company for $40 million and an increase in other regulatory assets, deferred and other deferred credits and liabilities of $49.2 million and $44.2 million, respectively, primarily due to increases in PPAs' deferred capacity expense.

The Company's ratio of common equity to total capitalization, including short-term debt, was 44.5% in 2012 and 43.7% in 2011. See Note 6 to the financial statements for additional information.

Sources of Capital

The Company plans to obtain the funds required for construction and other purposes from sources similar to those used in the past, which were primarily from operating cash flows, short-term debt, security issuances, term loans, and equity contributions from Southern Company. However, the amount, type, and timing of any future financings, if needed, will depend on regulatory approval, prevailing market conditions, and other factors.

Security issuances are subject to annual regulatory approval by the Florida PSC pursuant to its rules and regulations. Additionally, with respect to the public offering of securities, the Company files registration statements with the Securities and Exchange Commission (SEC) under the Securities Act of 1933, as amended (1933 Act). The amounts of securities authorized by the Florida PSC, as well as the amounts, if any, registered under the 1933 Act, are continuously monitored and appropriate filings are made to ensure flexibility in the capital markets.

The Company obtains financing separately without credit support from any affiliate. See Note 6 to the financial statements under "Bank Credit Arrangements" for additional information. The Southern Company system does not maintain a centralized cash or money pool. Therefore, funds of the Company are not commingled with funds of any other company in the Southern Company system.

The Company's current liabilities frequently exceed current assets because of the continued use of short-term debt as a funding source to meet scheduled maturities of long-term debt, as well as cash needs, which can fluctuate significantly due to the seasonality of the business.

At December 31, 2012, the Company had approximately $32.2 million of cash and cash equivalents. Committed credit arrangements with banks at December 31, 2012 were as follows:

Expires[a]				Executable Term-Loans		Due Within One Year	
2013	2014	Total	Unused	One Year	Two Years	Term Out	No Term Out
$80	$195	$275	$275	$45	$—	$45	$35

(a) No credit arrangements expire after 2014.

See Note 6 to the financial statements under "Bank Credit Arrangements" for additional information.

Most of these arrangements contain covenants that limit debt levels and contain cross default provisions that are restricted only to the indebtedness of the Company. The Company is currently in compliance with all such covenants. The Company expects to renew its credit arrangements, as needed, prior to expiration. These credit arrangements provide liquidity support to the Company's variable rate pollution control revenue bonds and commercial paper borrowings. As of December 31, 2012, the Company had $69 million of outstanding pollution control revenue bonds requiring liquidity support. In addition, the Company has substantial cash flow from operating activities and access to the capital markets to meet liquidity needs.

The Company may also meet short-term cash needs through a Southern Company subsidiary organized to issue and sell commercial paper at the request and for the benefit of the Company and the other traditional operating companies. Proceeds from such issuances for the benefit of the Company are loaned directly to the Company. The obligations of each company under these arrangements are several and there is no cross-affiliate credit support.

Details of short-term borrowings were as follows:

	Short-term Debt at the End of the Period [a]		Short-term Debt During the Period [b]		
	Amount Outstanding	Weighted Average Interest Rate	Average Outstanding	Weighted Average Interest Rate	Maximum Amount Outstanding
	(in millions)		*(in millions)*		*(in millions)*
December 31, 2012:					
Commercial paper	$ 124	0.3%	$ 69	0.3%	$ 124
December 31, 2011:					
Commercial paper	$ 111	0.2%	$ 53	0.2%	$ 111
Short-term bank debt	—	N/A	4	1.3%	30
Total	$ 111	0.2%	$ 57	0.3%	
December 31, 2010:					
Commercial paper	$ 92	0.3%	$ 44	0.3%	$ 108

(a) Excludes notes payable related to other energy service contracts of $3.2 million, $3.6 million, and $1.2 million at December 31, 2012, 2011, and 2010, respectively.

(b) Average and maximum amounts are based upon daily balances during the twelve-month periods ended December 31, 2012, 2011, and 2010.

Management believes that the need for working capital can be adequately met by utilizing commercial paper programs, lines of credit, and cash.

Financing Activities

In January 2012, the Company issued to Southern Company 400,000 shares of the Company's common stock, without par value, and realized proceeds of $40 million. Subsequent to December 31, 2012, the Company issued to Southern Company 400,000 shares of the Company's common stock, without par value, and realized proceeds of $40 million. The proceeds were used to repay a portion of the Company's short-term debt and for other general corporate purposes, including the Company's continuous construction program.

In May 2012, the Company issued $100 million aggregate principal amount of Series 2012A 3.10% Senior Notes due May 15, 2022. The net proceeds from the sale of the Series 2012A Senior Notes were used by the Company for the redemption in June 2012 of all of approximately $61 million aggregate principal amount of the Company's Series F 5.60% Senior Insured Quarterly Notes due April 1, 2033 and $30 million aggregate principal amount of the Company's Series H 5.25% Senior Notes due July 15, 2033, to repay a portion of its outstanding short-term indebtedness, and for general corporate purposes, including the Company's continuous construction program.

In November 2012, the Mississippi Business Finance Corporation issued $13 million aggregate principal amount of Mississippi Business Finance Corporation Solid Waste Disposal Facilities Revenue Refunding Bonds, Series 2012 (Gulf Power Company Project), due November 1, 2042 for the benefit of the Company. The proceeds were used to redeem the Mississippi Business Finance Corporation Solid Waste Disposal Facilities Revenue Refunding Bonds, Series 2002 (Gulf Power Company Project) due September 1, 2028.

In addition to any financings that may be necessary to meet capital requirements, contractual obligations, and storm-recovery, the Company plans to continue, when economically feasible, a program to retire higher-cost securities and replace these obligations with lower-cost capital if market conditions permit.

Credit Rating Risk

The Company does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. There are certain contracts that could require collateral, but not accelerated payment, in the event of a credit rating change to BBB- and/or Baa3 or below. These contracts are for physical electricity purchases and sales, fuel transportation and storage, and energy price risk management. The maximum potential collateral requirements under these contracts at December 31, 2012 were as follows:

Credit Ratings	Maximum Potential Collateral Requirements
	(in millions)
At BBB- and/or Baa3	$ 117
Below BBB- and/or Baa3	489

Included in these amounts are certain agreements that could require collateral in the event that one or more Southern Company system power pool participants has a credit rating change to below investment grade. Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. Additionally, any credit rating downgrade could impact the Company's ability to access capital markets, particularly the short-term debt market and the variable rate pollution control revenue bond market.

Market Price Risk

Due to cost-based rate regulation and other various cost recovery mechanisms, the Company continues to have limited exposure to market volatility in interest rates, commodity fuel prices, and prices of electricity. To manage the volatility attributable to these exposures, the Company nets the exposures, where possible, to take advantage of natural offsets and may enter into various derivative transactions for the remaining exposures pursuant to the Company's policies in areas such as counterparty exposure and risk management practices. The Company's policy is that derivatives are to be used primarily for hedging purposes and mandates strict adherence to all applicable risk management policies. Derivative positions are monitored using techniques including, but not limited to, market valuation, value at risk, stress testing, and sensitivity analysis.

To mitigate future exposure to changes in interest rates, the Company may enter into derivatives which are designated as hedges. The weighted average interest rate on $69.3 million of outstanding variable rate long-term debt that has not been hedged at January 1, 2013 was 0.13%. If the Company sustained a 100 basis point change in interest rates for all unhedged variable rate long-term debt, the change would affect annualized interest expense by approximately $693,000 at January 1, 2013. See Note 1 to the financial statements under "Financial Instruments" and Note 10 to the financial statements for additional information.

To mitigate residual risks relative to natural gas purchases, the Company continues to manage a financial hedging program for fuel purchased to operate its electric generating fleet implemented per the guidelines of the Florida PSC.

The changes in fair value of energy-related derivative contracts, substantially all of which are composed of regulatory hedges, for the years ended December 31 were as follows:

	2012 Changes	2011 Changes
	Fair Value	
	(in millions)	
Contracts outstanding at the beginning of the period, assets (liabilities), net	$ (41)	$ (11)
Contracts realized or settled	30	11
Current period changes[a]	(12)	(41)
Contracts outstanding at the end of the period, assets (liabilities), net	$ (23)	$ (41)

(a) Current period changes also include the changes in fair value of new contracts entered into during the period, if any.

The changes in the fair value positions of the energy-related derivative contracts, which are substantially all attributable to both the volume and the price of natural gas, for the years ended December 31 were as follows:

	2012 Changes	2011 Changes
	Fair Value	
	(in millions)	
Natural gas swaps	$ 17	$ (28)
Natural gas options	1	(2)
Other energy-related derivatives	—	—
Total changes	$ 18	$ (30)

The net hedge volumes of energy-related derivative contracts, for the years ended December 31 were as follows:

	2012	2011
	mmBtu* Volume	
	(in millions)	
Commodity – Natural gas swaps	71	35
Commodity – Natural gas options	—	3
Total hedge volume	71	38

*million British thermal units (mmBtu)

The weighted average swap contract cost above market prices was approximately $0.32 per mmBtu as of December 31, 2012 and $1.14 per mmBtu as of December 31, 2011. The change in option fair value is primarily attributable to the volatility of the market and the underlying change in the natural gas price. Natural gas settlements are recovered through the Company's fuel cost recovery clause.

At December 31, 2012 and 2011, substantially all of the Company's energy-related derivative contracts were designated as regulatory hedges and are related to the Company's fuel hedging program. Therefore, gains and losses are initially recorded as regulatory liabilities and assets, respectively, and then are included in fuel expense as they are recovered through the fuel cost recovery clause. Gains and losses on energy-related derivative contracts that are not designated or fail to qualify as hedges are recognized in the statements of income as incurred and were not material for any year presented.

The Company uses over-the-counter contracts that are not exchange traded but are fair valued using prices which are market observable, and thus fall into Level 2. See Note 9 to the financial statements for further discussion of fair value measurements. The maturities of the energy-related derivative contracts, which are all Level 2 of the fair value hierarchy, at December 31, 2012 were as follows:

	Fair Value Measurements December 31, 2012		
	Total	Maturity	
	Fair Value	Year 1	Years 2&3
	(in millions)		
Level 1	$ —	$ —	$ —
Level 2	(23)	(15)	(8)
Level 3	—	—	—
Fair value of contracts outstanding at end of period	$ (23)	$ (15)	$ (8)

The Company is exposed to market price risk in the event of nonperformance by counterparties to the energy-related derivative contracts. The Company only enters into agreements and material transactions with counterparties that have investment grade credit ratings by Moody's Investors Service, Inc. and Standard & Poor's Ratings Services, a division of The McGraw Hill Companies, Inc., or with counterparties who have posted collateral to cover potential credit exposure. Therefore, the Company

does not anticipate market risk exposure from nonperformance by the counterparties. For additional information, see Note 1 to the financial statements under "Financial Instruments" and Note 10 to the financial statements.

Capital Requirements and Contractual Obligations

The construction program of the Company consists of a base level capital investment and capital expenditures to comply with existing environmental statutes and regulations. These amounts include capital expenditures covered under long-term service agreements as well as capital expenditures and compliance costs associated with the MATS rule. Proposed water and coal combustion byproducts rules are not included in the construction program base level capital investment.

The Company's base level construction program investments for existing environmental statutes and regulations and the estimated incremental compliance costs related to the proposed water and coal combustion byproducts rules over the 2013 through 2015 three-year period, based on the assumption that coal combustion byproducts will continue to be regulated as non-hazardous solid waste under the proposed rule, are estimated as follows:

	2013	2014	2015
Construction program:		*(in millions)*	
Base capital	$ 177	$ 141	$ 138
Existing environmental statutes and regulations, including the MATS rule	158	319	167
Total construction program base level capital investment	**$ 335**	**$ 460**	**$ 305**
Potential incremental environmental compliance investment:			
Proposed water and coal combustion byproducts rules	$ —	$ 18	$ 70

See FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations" for additional information.

The construction program is subject to periodic review and revision, and actual construction costs may vary from these estimates because of numerous factors. These factors include: changes in business conditions; changes in load projections; storm impacts; changes in environmental statutes and regulations; the outcome of any legal challenges to the environmental rules; changes in generating plants, including unit retirements and replacements and adding or changing fuel sources at existing units, to meet regulatory requirements; changes in the expected environmental compliance program; changes in FERC rules and regulations; Florida PSC approvals; changes in legislation; the cost and efficiency of construction labor, equipment, and materials; project scope and design changes; and the cost of capital. In addition, there can be no assurance that costs related to capital expenditures will be fully recovered.

In addition, as discussed in Note 2 to the financial statements, the Company provides postretirement benefits to substantially all employees and funds trusts to the extent required by the FERC and the Florida PSC.

Other funding requirements related to obligations associated with scheduled maturities of long-term debt, as well as the related interest, derivative obligations, preference stock dividends, leases, and other purchase commitments are detailed in the contractual obligations table that follows. See Notes 1, 2, 5, 6, 7, and 10 to the financial statements for additional information.

Contractual Obligations

	2013	2014-2015	2016-2017	After 2017	Uncertain Timing[d]	Total
			(in thousands)			
Long-term debt[a] –						
Principal	$ 60,000	$ 75,000	$ 195,000	$ 923,955	$ —	$ 1,253,955
Interest	55,095	101,295	91,790	628,206	—	876,386
Financial derivative obligations[b]	16,529	10,209	374	—	—	27,112
Preference stock dividends[c]	6,203	12,405	12,405	—	—	31,013
Operating leases	18,930	18,702	2,128	—	—	39,760
Unrecognized tax benefits[d]	—	—	—	—	5,007	5,007
Purchase commitments –						
Capital[e]	313,952	764,631	—	—	—	1,078,583
Fuel[f]	347,607	459,534	216,967	160,095	—	1,184,203
Purchased power[g]	49,015	160,304	184,613	500,398	—	894,330
Other[h]	15,862	32,923	19,194	15,846	—	83,825
Pension and other postretirement benefit plans[i]	3,928	8,559	—	—	—	12,487
Total	$ 887,121	$1,643,562	$ 722,471	$2,228,500	$ 5,007	$ 5,486,661

(a) All amounts are reflected based on final maturity dates. The Company plans to continue to retire higher-cost securities and replace these obligations with lower-cost capital if market conditions permit. Variable rate interest obligations are estimated based on rates as of January 1, 2013, as reflected in the statements of capitalization. Fixed rates include, where applicable, the effects of interest rate derivatives employed to manage interest rate risk.

(b) For additional information, see Notes 1 and 10 to the financial statements.

(c) Preference stock does not mature; therefore, amounts are provided for the next five years only.

(d) The timing related to the realization of $5.0 million in unrecognized tax benefits in individual years beyond 12 months cannot be reasonably and reliably estimated due to uncertainties in the timing of the effective settlement of tax positions. See Note 5 to the financial statements under "Unrecognized Tax Benefits" for additional information.

(e) The Company provides estimated capital expenditures for a three-year period, including capital expenditures and compliance costs associated with existing environmental regulations, including the MATS rule. Such amounts exclude the Company's estimates of potential incremental environmental compliance investment to comply with proposed water and coal combustion byproducts rules, which are approximately $18 million and $70 million for years 2014 and 2015, respectively. These amounts also exclude capital expenditures covered under long-term service agreements, which are reflected separately. At December 31, 2012, significant purchase commitments were outstanding in connection with the construction program. See FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations" for additional information.

(f) Includes commitments to purchase coal and natural gas, as well as the related transportation and storage. In most cases, these contracts contain provisions for price escalation, minimum purchase levels, and other financial commitments. Natural gas purchase commitments are based on various indices at the time of delivery. Amounts reflected for natural gas purchase commitments have been estimated based on the New York Mercantile Exchange future prices at December 31, 2012.

(g) The capacity and transmission related costs associated with PPAs are recovered through the purchased power capacity clause. See Notes 3 and 7 to the financial statements for additional information.

(h) Includes long-term service agreements and contracts for the procurement of limestone. Long-term service agreements include price escalation based on inflation indices.

(i) The Company forecasts contributions to the pension and other postretirement benefit plans over a three-year period. The Company anticipates no mandatory contributions to the qualified pension plan during the next three years. Amounts presented represent estimated benefit payments for the nonqualified pension plans, estimated non-trust benefit payments for the other postretirement benefit plans, and estimated contributions to the other postretirement benefit plan trusts, all of which will be made from the Company's corporate assets. See Note 2 to the financial statements for additional information related to the pension and other postretirement benefit plans, including estimated benefit payments. Certain benefit payments will be made through the related benefit plans. Other benefit payments will be made from the Company's corporate assets.

Cautionary Statement Regarding Forward-Looking Statements

The Company's 2012 Annual Report contains forward-looking statements. Forward-looking statements include, among other things, statements concerning retail sales, retail rates, customer growth, economic recovery, fuel and environmental cost recovery and other rate actions, current and proposed environmental regulations and related estimated expenditures, access to sources of capital, projections for the qualified pension plan and postretirement benefit plan contributions, financing activities, start and completion of construction projects, filings with state and federal regulatory authorities, impact of the Tax Relief Act, impact of the ATRA, estimated sales and purchases under new power sale and purchase agreements, and estimated construction and other expenditures. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "could," "should," "expects," "plans," "anticipates," "believes," "estimates," "projects," "predicts," "potential," or "continue" or the negative of these terms or other similar terminology. There are various factors that could cause actual results to differ materially from those suggested by the forward-looking statements; accordingly, there can be no assurance that such indicated results will be realized. These factors include:

- the impact of recent and future federal and state regulatory changes, including legislative and regulatory initiatives regarding deregulation and restructuring of the electric utility industry, environmental laws including regulation of water, coal combustion byproducts, and emissions of sulfur, nitrogen, carbon, soot, particulate matter, hazardous air pollutants, including mercury, and other substances, financial reform legislation, and also changes in tax and other laws and regulations to which the Company is subject, as well as changes in application of existing laws and regulations;
- current and future litigation, regulatory investigations, proceedings, or inquiries, including the pending EPA civil action against the Company and Internal Revenue Service and state tax audits;
- the effects, extent, and timing of the entry of additional competition in the markets in which the Company operates;
- variations in demand for electricity, including those relating to weather, the general economy and recovery from the recent recession, population and business growth (and declines), the effects of energy conservation measures, and any potential economic impacts resulting from federal fiscal decisions;
- available sources and costs of fuels;
- effects of inflation;
- ability to control costs and avoid cost overruns during the development and construction of facilities;
- investment performance of the Company's employee benefit plans;
- advances in technology;
- state and federal rate regulations and the impact of pending and future rate cases and negotiations, including rate actions relating to fuel and other cost recovery mechanisms;
- internal restructuring or other restructuring options that may be pursued;
- potential business strategies, including acquisitions or dispositions of assets or businesses, which cannot be assured to be completed or beneficial to the Company;
- the ability of counterparties of the Company to make payments as and when due and to perform as required;
- the ability to obtain new short- and long-term contracts with wholesale customers;
- the direct or indirect effect on the Company's business resulting from terrorist incidents and the threat of terrorist incidents, including cyber intrusion;
- interest rate fluctuations and financial market conditions and the results of financing efforts, including the Company's credit ratings;
- the impacts of any potential U.S. credit rating downgrade or other sovereign financial issues, including impacts on interest rates, access to capital markets, impacts on currency exchange rates, counterparty performance, and the economy in general;
- the ability of the Company to obtain additional generating capacity at competitive prices;
- catastrophic events such as fires, earthquakes, explosions, floods, hurricanes, droughts, pandemic health events such as influenzas, or other similar occurrences;
- the direct or indirect effects on the Company's business resulting from incidents affecting the U.S. electric grid or operation of generating resources;
- the effect of accounting pronouncements issued periodically by standard setting bodies; and

- other factors discussed elsewhere herein and in other reports (including the Form 10-K) filed by the Company from time to time with the SEC.

The Company expressly disclaims any obligation to update any forward-looking statements.

STATEMENTS OF INCOME
For the Years Ended December 31, 2012, 2011, and 2010
Gulf Power Company 2012 Annual Report

	2012	2011	2010
		(in thousands)	
Operating Revenues:			
Retail revenues	**$ 1,144,471**	$ 1,208,490	$ 1,308,726
Wholesale revenues, non-affiliates	**106,881**	133,555	109,172
Wholesale revenues, affiliates	**123,636**	111,346	110,051
Other revenues	**64,774**	66,421	62,260
Total operating revenues	**1,439,762**	1,519,812	1,590,209
Operating Expenses:			
Fuel	**544,936**	662,283	742,322
Purchased power, non-affiliates	**51,421**	48,882	41,278
Purchased power, affiliates	**22,665**	41,612	55,948
Other operations and maintenance	**314,195**	311,358	280,585
Depreciation and amortization	**141,038**	129,651	121,498
Taxes other than income taxes	**97,313**	101,302	101,778
Total operating expenses	**1,171,568**	1,295,088	1,343,409
Operating Income	**268,194**	224,724	246,800
Other Income and (Expense):			
Allowance for equity funds used during construction	**5,221**	9,914	7,213
Interest income	**1,408**	54	123
Interest expense, net of amounts capitalized	**(60,250)**	(58,150)	(51,897)
Other income (expense), net	**(3,227)**	(4,066)	(3,011)
Total other income and (expense)	**(56,848)**	(52,248)	(47,572)
Earnings Before Income Taxes	**211,346**	172,476	199,228
Income taxes	**79,211**	61,268	71,514
Net Income	**132,135**	111,208	127,714
Dividends on Preference Stock	**6,203**	6,203	6,203
Net Income After Dividends on Preference Stock	**$ 125,932**	$ 105,005	$ 121,511

The accompanying notes are an integral part of these financial statements.

STATEMENTS OF COMPREHENSIVE INCOME
For the Years Ended December 31, 2012, 2011, and 2010
Gulf Power Company 2012 Annual Report

	2012	2011	2010
		(in thousands)	
Net Income	**$ 132,135**	$ 111,208	$ 127,714
Other comprehensive income (loss):			
Qualifying hedges:			
Changes in fair value, net of tax of $-, $-, and $(542), respectively	—	—	(863)
Reclassification adjustment for amounts included in net income, net of tax of $360, $360, and $376, respectively	**573**	573	598
Total other comprehensive income (loss)	**573**	573	(265)
Comprehensive Income	**$ 132,708**	$ 111,781	$ 127,449

The accompanying notes are an integral part of these financial statements.

STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2012, 2011, and 2010
Gulf Power Company 2012 Annual Report

	2012	2011	2010
		(in thousands)	
Operating Activities:			
Net income	$ 132,135	$ 111,208	$ 127,714
Adjustments to reconcile net income to net cash provided from operating activities —			
Depreciation and amortization, total	147,723	135,790	127,897
Deferred income taxes	174,305	63,228	82,681
Allowance for equity funds used during construction	(5,221)	(9,914)	(7,213)
Pension, postretirement, and other employee benefits	(8,109)	(356)	(23,964)
Stock based compensation expense	1,647	1,318	1,101
Hedge settlements	—	—	1,530
Other, net	4,518	(8,258)	(4,126)
Changes in certain current assets and liabilities —			
-Receivables	8,713	21,518	(36,687)
-Prepayments	417	10,150	(10,796)
-Fossil fuel stock	(6,144)	17,519	15,766
-Materials and supplies	(3,035)	(5,073)	(6,251)
-Prepaid income taxes	355	26,901	(29,630)
-Other current assets	—	40	55
-Accounts payable	(5,195)	(2,528)	15,683
-Accrued taxes	(4,705)	1,475	1,427
-Accrued compensation	481	25	5,122
-Over recovered regulatory clause revenues	(10,858)	10,247	3,192
-Other current liabilities	(7,837)	2,937	4,279
Net cash provided from operating activities	419,190	376,227	267,780
Investing Activities:			
Property additions	(313,257)	(324,372)	(285,793)
Distribution of restricted cash from pollution control revenue bonds	—	—	6,347
Cost of removal net of salvage	(28,993)	(14,471)	(1,145)
Construction payables	1,161	2,902	(21,581)
Payments pursuant to long-term service agreements	(8,119)	(8,007)	(6,011)
Other investing activities	656	420	(262)
Net cash used for investing activities	(348,552)	(343,528)	(308,445)
Financing Activities:			
Increase (decrease) in notes payable, net	16,075	21,324	4,451
Proceeds —			
Common stock issued to parent	40,000	50,000	50,000
Capital contributions from parent company	2,106	2,101	2,242
Pollution control revenue bonds	13,000	—	21,000
Senior notes	100,000	125,000	300,000
Redemptions —			
Pollution control revenue bonds	(13,000)	—	—
Senior notes	(91,363)	(608)	(215,515)
Other long-term debt	—	(110,000)	—
Payment of preference stock dividends	(6,203)	(6,203)	(6,203)
Payment of common stock dividends	(115,800)	(110,000)	(104,300)
Other financing activities	(614)	(3,419)	(3,253)
Net cash provided from (used for) financing activities	(55,799)	(31,805)	48,422
Net Change in Cash and Cash Equivalents	14,839	894	7,757
Cash and Cash Equivalents at Beginning of Year	17,328	16,434	8,677
Cash and Cash Equivalents at End of Year	$ 32,167	$ 17,328	$ 16,434
Supplemental Cash Flow Information:			
Cash paid during the period for —			
Interest (net of $2,500, $3,951 and $2,875 capitalized, respectively)	$ 58,255	$ 55,486	$ 42,521
Income taxes (net of refunds)	(96,639)	(26,345)	17,224
Noncash transactions — accrued property additions at year-end	27,369	19,439	14,475

The accompanying notes are an integral part of these financial statements.

BALANCE SHEETS
At December 31, 2012 and 2011
Gulf Power Company 2012 Annual Report

Assets	2012	2011
	(in thousands)	
Current Assets:		
Cash and cash equivalents	$ **32,167**	$ 17,328
Receivables —		
Customer accounts receivable	**58,449**	72,754
Unbilled revenues	**53,363**	49,921
Under recovered regulatory clause revenues	**6,138**	5,530
Other accounts and notes receivable	**11,859**	13,350
Affiliated companies	**13,624**	14,844
Accumulated provision for uncollectible accounts	**(1,490)**	(1,962)
Fossil fuel stock, at average cost	**153,710**	147,567
Materials and supplies, at average cost	**53,365**	49,781
Other regulatory assets, current	**30,576**	35,849
Prepaid expenses	**62,877**	28,327
Other current assets	**2,690**	2,051
Total current assets	**477,328**	435,340
Property, Plant, and Equipment:		
In service	**4,260,844**	3,846,446
Less accumulated provision for depreciation	**1,168,055**	1,124,291
Plant in service, net of depreciation	**3,092,789**	2,722,155
Construction work in progress	**136,062**	287,173
Total property, plant, and equipment	**3,228,851**	3,009,328
Other Property and Investments	**15,737**	16,394
Deferred Charges and Other Assets:		
Deferred charges related to income taxes	**50,139**	48,210
Other regulatory assets, deferred	**372,294**	323,116
Other deferred charges and assets	**33,053**	39,493
Total deferred charges and other assets	**455,486**	410,819
Total Assets	$ **4,177,402**	$ 3,871,881

The accompanying notes are an integral part of these financial statements.

BALANCE SHEETS
At December 31, 2012 and 2011
Gulf Power Company 2012 Annual Report

Liabilities and Stockholder's Equity	2012	2011
		(in thousands)
Current Liabilities:		
Securities due within one year	**$ 60,000**	$ —
Notes payable	**127,002**	114,507
Accounts payable —		
Affiliated	**66,161**	54,874
Other	**54,551**	63,265
Customer deposits	**34,749**	35,779
Accrued taxes —		
Accrued income taxes	**45**	1,362
Other accrued taxes	**7,036**	12,114
Accrued interest	**12,364**	14,018
Accrued compensation	**14,966**	14,485
Other regulatory liabilities, current	**25,887**	35,639
Liabilities from risk management activities	**16,529**	22,786
Other current liabilities	**19,930**	22,916
Total current liabilities	**439,220**	391,745
Long-Term Debt (See accompanying statements)	**1,185,870**	1,235,447
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	**648,952**	458,978
Accumulated deferred investment tax credits	**5,408**	6,760
Employee benefit obligations	**126,871**	109,740
Other cost of removal obligations	**213,413**	214,598
Other regulatory liabilities, deferred	**47,863**	44,843
Other deferred credits and liabilities	**231,065**	186,824
Total deferred credits and other liabilities	**1,273,572**	1,021,743
Total Liabilities	**2,898,662**	2,648,935
Preference Stock (See accompanying statements)	**97,998**	97,998
Common Stockholder's Equity (See accompanying statements)	**1,180,742**	1,124,948
Total Liabilities and Stockholder's Equity	**$ 4,177,402**	$ 3,871,881
Commitments and Contingent Matters (See notes)		

The accompanying notes are an integral part of these financial statements.

STATEMENTS OF CAPITALIZATION
At December 31, 2012 and 2011
Gulf Power Company 2012 Annual Report

	2012	2011	2012	2011
	(in thousands)		*(percent of total)*	
Long Term Debt:				
Long-term notes payable —				
4.35% due 2013	**$ 60,000**	$ 60,000		
4.90% due 2014	**75,000**	75,000		
5.30% due 2016	**110,000**	110,000		
5.90% due 2017	**85,000**	85,000		
3.10% to 5.75% due 2020-2051	**615,000**	606,363		
Total long-term notes payable	**945,000**	936,363		
Other long-term debt —				
Pollution control revenue bonds —				
0.55% to 6.00% due 2022-2049	**239,625**	239,625		
Variable rates (0.13% to 0.17% at 1/1/13) due 2022-2039	**69,330**	69,330		
Total other long-term debt	**308,955**	308,955		
Unamortized debt discount	**(8,085)**	(9,871)		
Total long-term debt (annual interest requirement — $55.1 million)	**1,245,870**	1,235,447		
Less amount due within one year	**60,000**	—		
Long-term debt excluding amount due within one year	**1,185,870**	1,235,447	**48.1%**	50.2%
Preferred and Preference Stock:				
Authorized - 20,000,000 shares—preferred stock				
- 10,000,000 shares—preference stock				
Outstanding - $100 par or stated value — 6% preference stock	**53,886**	53,886		
— 6.45% preference stock	**44,112**	44,112		
- 1,000,000 shares (non-cumulative)				
Total preference stock (annual dividend requirement — $6.2 million)	**97,998**	97,998	**4.0**	4.0
Common Stockholder's Equity:				
Common stock, without par value —				
Authorized - 20,000,000 shares				
Outstanding - 2012: 4,542,717 shares				
- 2011: 4,142,717 shares	**393,060**	353,060		
Paid-in capital	**547,798**	542,709		
Retained earnings	**241,465**	231,333		
Accumulated other comprehensive income (loss)	**(1,581)**	(2,154)		
Total common stockholder's equity	**1,180,742**	1,124,948	**47.9**	45.8
Total Capitalization	**$ 2,464,610**	$ 2,458,393	**100.0%**	100.0%

The accompanying notes are an integral part of these financial statements.

STATEMENTS OF COMMON STOCKHOLDER'S EQUITY
For the Years Ended December 31, 2012, 2011, and 2010
Gulf Power Company 2012 Annual Report

	Number of Common Shares Issued	Common Stock	Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
			(in thousands)			
Balance at December 31, 2009	3,143	$ 253,060	$ 534,577	$ 219,117	$ (2,462)	$ 1,004,292
Net income after dividends on preference stock	—	—	—	121,511	—	121,511
Issuance of common stock	500	50,000	—	—	—	50,000
Capital contributions from parent company	—	—	3,798	—	—	3,798
Other comprehensive income (loss)	—	—	—	—	(265)	(265)
Cash dividends on common stock	—	—	—	(104,300)	—	(104,300)
Balance at December 31, 2010	3,643	303,060	538,375	236,328	(2,727)	1,075,036
Net income after dividends on preference stock	—	—	—	105,005	—	105,005
Issuance of common stock	500	50,000	—	—	—	50,000
Capital contributions from parent company	—	—	4,334	—	—	4,334
Other comprehensive income (loss)	—	—	—	—	573	573
Cash dividends on common stock	—	—	—	(110,000)	—	(110,000)
Balance at December 31, 2011	**4,143**	**353,060**	**542,709**	**231,333**	**(2,154)**	**1,124,948**
Net income after dividends on preference stock	—	—	—	**125,932**	—	**125,932**
Issuance of common stock	**400**	**40,000**	—	—	—	**40,000**
Capital contributions from parent company	—	—	**5,089**	—	—	**5,089**
Other comprehensive income (loss)	—	—	—	—	**573**	**573**
Cash dividends on common stock	—	—	—	**(115,800)**	—	**(115,800)**
Balance at December 31, 2012	**4,543**	**$ 393,060**	**$ 547,798**	**$ 241,465**	**$ (1,581)**	**$ 1,180,742**

The accompanying notes are an integral part of these financial statements.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

General

Gulf Power Company (the Company) is a wholly owned subsidiary of The Southern Company (Southern Company), which is the parent company of four traditional operating companies, as well as Southern Power Company (Southern Power), Southern Company Services, Inc. (SCS), Southern Communications Services, Inc. (SouthernLINC Wireless), Southern Company Holdings, Inc. (Southern Holdings), Southern Nuclear Operating Company, Inc. (Southern Nuclear), and other direct and indirect subsidiaries. The traditional operating companies — the Company, Alabama Power Company (Alabama Power), Georgia Power Company (Georgia Power), and Mississippi Power Company (Mississippi Power) — are vertically integrated utilities providing electric service in four Southeastern states. The Company operates as a vertically integrated utility providing electricity to retail customers in northwest Florida and to wholesale customers in the Southeast. Southern Power constructs, acquires, owns, and manages generation assets, including renewable energy projects, and sells electricity at market-based rates in the wholesale market. SCS, the system service company, provides, at cost, specialized services to Southern Company and its subsidiary companies. SouthernLINC Wireless provides digital wireless communications for use by Southern Company and its subsidiary companies and also markets these services to the public and provides fiber cable services within the Southeast. Southern Holdings is an intermediate holding company subsidiary, primarily for Southern Company's investments in leveraged leases. Southern Nuclear operates and provides services to the Southern Company system's nuclear power plants.

The equity method is used for entities in which the Company has significant influence but does not control.

The Company is subject to regulation by the Federal Energy Regulatory Commission (FERC) and the Florida Public Service Commission (PSC). The Company follows generally accepted accounting principles (GAAP) in the U.S. and complies with the accounting policies and practices prescribed by its regulatory commissions. The preparation of financial statements in conformity with GAAP requires the use of estimates, and the actual results may differ from those estimates. Certain prior years' data presented in the financial statements have been reclassified to conform to the current year presentation.

Affiliate Transactions

The Company has an agreement with SCS under which the following services are rendered to the Company at direct or allocated cost: general and design engineering, operations, purchasing, accounting, finance and treasury, tax, information technology, marketing, auditing, insurance and pension administration, human resources, systems and procedures, digital wireless communications, and other services with respect to business and operations and power pool transactions. Costs for these services amounted to $95.9 million, $97.4 million, and $98.8 million during 2012, 2011, and 2010, respectively. Cost allocation methodologies used by SCS prior to the repeal of the Public Utility Holding Company Act of 1935, as amended, were approved by the Securities and Exchange Commission (SEC). Subsequently, additional cost allocation methodologies have been reported to the FERC and management believes they are reasonable. The FERC permits services to be rendered at cost by system service companies.

The Company has agreements with Georgia Power and Mississippi Power under which the Company owns a portion of Plant Scherer and Plant Daniel, respectively. Georgia Power operates Plant Scherer and Mississippi Power operates Plant Daniel. The Company reimbursed Georgia Power $6.9 million, $6.7 million, and $8.9 million and Mississippi Power $21.1 million, $23.4 million, and $25.0 million in 2012, 2011, and 2010, respectively, for its proportionate share of related expenses. See Note 4 and Note 7 under "Operating Leases" for additional information.

The Company entered into a power purchase agreement (PPA) with Southern Power for a total of approximately 292 megawatts (MWs) annually from June 2009 through May 2014. Purchased power expenses associated with the PPA were $14.7 million, $14.3 million, and $14.5 million in 2012, 2011, and 2010, respectively, and fuel costs associated with the PPA were $2.6 million, $1.8 million, and $3.3 million in 2012, 2011, and 2010, respectively. These costs have been approved for recovery by the Florida PSC through the Company's fuel and purchased power capacity cost recovery clauses. Additionally, the Company had $4.2 million of deferred capacity expenses included in prepaid expenses and other regulatory liabilities, current in the balance sheets at December 31, 2012 and 2011, respectively. See Note 7 under "Fuel and Purchased Power Agreements" for additional information.

The Company has an agreement with Georgia Power under the transmission facility cost allocation tariff for delivery of power from the Company's resources in the state of Georgia. The Company reimbursed Georgia Power $2.4 million in each of the years 2012, 2011, and 2010 for its share of related expenses.

The Company has an agreement with Alabama Power under which Alabama Power will make transmission system upgrades to ensure firm delivery of energy under a non-affiliate PPA, which was entered into in 2009 for the capacity and energy from a combined cycle plant located in Autauga County, Alabama. Revenue requirement obligations to Alabama Power for these upgrades are estimated to be $136.7 million for the entire project. These costs began in July 2012 and will continue through 2023. The Company reimbursed Alabama Power $3.0 million in 2012 for the revenue requirements. These costs have been approved for recovery by the Florida PSC through the Company's purchased power capacity cost recovery clause and by the FERC in the transmission facilities cost allocation tariff.

The Company provides incidental services to and receives such services from other Southern Company subsidiaries which are generally minor in duration and amount. Except as described herein, the Company neither provided nor received any material services to or from affiliates in 2012 or 2010. In 2011, the Company provided storm restoration assistance to Alabama Power totaling $1.4 million.

The traditional operating companies, including the Company, and Southern Power may jointly enter into various types of wholesale energy, natural gas, and certain other contracts, either directly or through SCS, as agent. Each participating company may be jointly and severally liable for the obligations incurred under these agreements. See Note 7 under "Fuel and Purchased Power Agreements" for additional information.

New Accounting Pronouncements

In June 2011, the Financial Accounting Standards Board (FASB) issued guidance, ASU 2011-05, *Presentation of Comprehensive Income*, requiring companies to present the total of comprehensive income, the components of net income, and the components of other comprehensive income, in a single continuous statement of comprehensive income or in two separate but consecutive statements. In October 2012, the FASB issued additional guidance, ASU 2012-04, *Technical Corrections and Improvements* (ASU 2012-04), in which it clarified that those companies presenting consecutive statements must begin the statement of comprehensive income with net income. The Company retroactively adopted the guidance in ASU 2012-04 beginning with its financial statements for the three years ended December 31, 2012, 2011, and 2010.

Regulatory Assets and Liabilities

The Company is subject to the provisions of the FASB in accounting for the effects of rate regulation. Regulatory assets represent probable future revenues associated with certain costs that are expected to be recovered from customers through the ratemaking process. Regulatory liabilities represent probable future reductions in revenues associated with amounts that are expected to be credited to customers through the ratemaking process.

Regulatory assets and (liabilities) reflected in the balance sheets at December 31 relate to:

	2012	2011	Note
	(in thousands)		
Deferred income tax charges	$ 46,788	$ 44,533	(a)
Deferred income tax charges — Medicare subsidy	3,678	4,005	(b)
Asset retirement obligations	(5,793)	(5,653)	(a,j)
Other cost of removal obligations	(213,413)	(214,598)	(a)
Deferred income tax credits	(6,515)	(8,113)	(a)
Loss on reacquired debt	16,400	14,437	(c)
Vacation pay	9,238	8,973	(d,j)
Under recovered regulatory clause revenues	3,523	3,133	(e)
Over recovered regulatory clause revenues	(17,092)	(27,950)	(e)
Property damage reserve	(31,956)	(30,473)	(f)
Fuel hedging (realized and unrealized) losses	29,038	43,071	(g,j)
Fuel hedging (realized and unrealized) gains	(4,358)	(197)	(g,j)
PPA charges	137,568	94,986	(j,k)
Generation site selection/evaluation costs	1,344	20,415	(l)
Other regulatory assets	9,690	1,675	(e,j)
Environmental remediation	60,452	61,625	(h,j)
PPA credits	(7,502)	(7,536)	(j,k)
Other regulatory liabilities	(534)	(798)	(f)
Retiree benefit plans, net	141,429	116,091	(i,j)
Total regulatory assets (liabilities), net	$ 171,985	$ 117,626	

Note: The recovery and amortization periods for these regulatory assets and (liabilities) are as follows:

(a) Asset retirement and removal assets and liabilities are recorded, deferred income tax assets are recovered, and deferred income tax liabilities are amortized over the related property lives, which may range up to 65 years. Asset retirement and removal assets and liabilities will be settled and trued up following completion of the related activities.

(b) Recovered and amortized over periods not exceeding 14 years.

(c) Recovered over either the remaining life of the original issue or, if refinanced, over the life of the new issue, which may range up to 40 years.

(d) Recorded as earned by employees and recovered as paid, generally within one year. This includes both vacation and banked holiday pay.

(e) Recorded and recovered or amortized as approved by the Florida PSC, generally within one year.

(f) Recorded and recovered or amortized as approved by the Florida PSC.

(g) Fuel hedging assets and liabilities are recognized over the life of the underlying hedged purchase contracts, which generally do not exceed five years. Upon final settlement, costs are recovered through the fuel cost recovery clause.

(h) Recovered through the environmental cost recovery clause when the remediation is performed.

(i) Recovered and amortized over the average remaining service period which may range up to 14 years. See Note 2 for additional information.

(j) Not earning a return as offset in rate base by a corresponding asset or liability.

(k) Recovered over the life of the PPA for periods up to 14 years.

(l) Deferred pursuant to Florida Statute while the Company continues to evaluate certain potential new generation projects.

In the event that a portion of the Company's operations is no longer subject to applicable accounting rules for rate regulation, the Company would be required to write off to income or reclassify to accumulated other comprehensive income (OCI) related regulatory assets and liabilities that are not specifically recoverable through regulated rates. In addition, the Company would be required to determine if any impairment to other assets, including plant, exists and write down the assets, if impaired, to their fair values. All regulatory assets and liabilities are to be reflected in rates. See Note 3 under "Retail Regulatory Matters" for additional information.

Revenues

Wholesale capacity revenues are generally recognized on a levelized basis over the appropriate contract period. Energy and other revenues are recognized as services are provided. Unbilled revenues related to retail sales are accrued at the end of each fiscal period. Electric rates for the Company include provisions to adjust billings for fluctuations in fuel costs, the energy component of purchased power costs, and certain other costs. The Company continuously monitors the over or under recovered fuel cost balance in light of the inherent variability in fuel costs. The Company is required to notify the Florida PSC if the projected fuel cost over or under recovery is expected to exceed 10% of the projected fuel revenue applicable for the period and indicate if an adjustment to the fuel cost recovery factor is being requested. The Company has similar retail cost recovery clauses for energy conservation costs, purchased power capacity costs, and environmental compliance costs. Revenues are adjusted for differences between these actual costs and amounts billed in current regulated rates. Under or over recovered regulatory clause revenues are recorded in the balance sheets and are recovered or returned to customers through adjustments to the billing factors. Annually, the Company petitions for recovery of projected costs including any true-up amounts from prior periods, and approved rates are implemented each January. See Note 3 under "Retail Regulatory Matters" for additional information.

The Company has a diversified base of customers. No single customer or industry comprises 10% or more of revenues. For all periods presented, uncollectible accounts averaged less than 1% of revenues.

Fuel Costs

Fuel costs are expensed as the fuel is used. Fuel expense generally includes fuel transportation costs and the cost of purchased emissions allowances as they are used. Fuel expense and emissions allowance costs are recovered by the Company through the fuel cost recovery and environmental cost recovery rates, respectively, approved annually by the Florida PSC.

Income and Other Taxes

The Company uses the liability method of accounting for deferred income taxes and provides deferred income taxes for all significant income tax temporary differences. Investment tax credits utilized are deferred and amortized to income over the average life of the related property. Taxes that are collected from customers on behalf of governmental agencies to be remitted to these agencies are presented net on the statements of income.

In accordance with accounting standards related to the uncertainty in income taxes, the Company recognizes tax positions that are "more likely than not" of being sustained upon examination by the appropriate taxing authorities. See Note 5 under "Unrecognized Tax Benefits" for additional information.

Property, Plant, and Equipment

Property, plant, and equipment is stated at original cost less any regulatory disallowances and impairments. Original cost includes: materials; labor; minor items of property; appropriate administrative and general costs; payroll-related costs such as taxes, pensions, and other benefits; and the interest capitalized and cost of equity funds used during construction.

The Company's property, plant, and equipment in service consisted of the following at December 31:

	2012	2011
	(in thousands)	
Generation	$ 2,598,773	$ 2,283,494
Transmission	429,341	368,542
Distribution	1,069,065	1,030,546
General	161,379	161,322
Plant acquisition adjustment	2,286	2,542
Total plant in service	$ 4,260,844	$ 3,846,446

The cost of replacements of property, exclusive of minor items of property, is capitalized. The cost of maintenance, repairs, and replacement of minor items of property is charged to other operations and maintenance expense as incurred or performed.

Depreciation and Amortization

Depreciation of the original cost of utility plant in service is provided primarily by using composite straight-line rates, which approximated 3.6% in 2012, 3.5% in 2011, and 3.5% in 2010. Depreciation studies are conducted periodically to update the composite rates. These studies are approved by the Florida PSC and the FERC. When property subject to depreciation is retired or otherwise disposed of in the normal course of business, its original cost, together with the cost of removal, less salvage, is charged to accumulated depreciation. For other property dispositions, the applicable cost and accumulated depreciation are removed from the balance sheet accounts, and a gain or loss is recognized. Minor items of property included in the original cost of the plant are retired when the related property unit is retired.

Asset Retirement Obligations and Other Costs of Removal

Asset retirement obligations are computed as the present value of the ultimate costs for an asset's future retirement and are recorded in the period in which the liability is incurred. The costs are capitalized as part of the related long-lived asset and depreciated over the asset's useful life. The Company has received an order from the Florida PSC allowing the continued accrual of other future retirement costs for long-lived assets that the Company does not have a legal obligation to retire. Accordingly, the accumulated removal costs for these obligations are reflected in the balance sheets as a regulatory liability.

The liability for asset retirement obligations primarily relates to the Company's combustion turbines at its Pea Ridge facility, various landfill sites, a barge unloading dock, asbestos removal, ash ponds, and disposal of polychlorinated biphenyls in certain transformers. The Company also has identified retirement obligations related to certain transmission and distribution facilities, certain wireless communication towers, and certain structures authorized by the U.S. Army Corps of Engineers. However, liabilities for the removal of these assets have not been recorded because the range of time over which the Company may settle these obligations is unknown and cannot be reasonably estimated. The Company will continue to recognize in the statements of income allowed removal costs in accordance with its regulatory treatment. Any differences between costs recognized in accordance with accounting standards related to asset retirement and environmental obligations and those reflected in rates are recognized as either a regulatory asset or liability, as ordered by the Florida PSC, and are reflected in the balance sheets.

Details of the asset retirement obligations included in the balance sheets are as follows:

	2012	2011
	(in thousands)	
Balance at beginning of year	$ 10,729	$ 11,470
Liabilities incurred	—	106
Liabilities settled	(107)	(1,050)
Accretion	507	545
Cash flow revisions	4,926	(342)
Balance at end of year	$ 16,055	$ 10,729

Allowance for Funds Used During Construction

In accordance with regulatory treatment, the Company records allowance for funds used during construction (AFUDC), which represents the estimated debt and equity costs of capital funds that are necessary to finance the construction of new regulated facilities. While cash is not realized currently from such allowance, AFUDC increases the revenue requirement over the service life of the plant through a higher rate base and higher depreciation. The equity component of AFUDC is not included in calculating taxable income. The average annual AFUDC rate was 6.72% for the year 2012. The average annual AFUDC rate was 7.65% for both 2011 and 2010. AFUDC, net of income taxes, as a percentage of net income after dividends on preference stock was 5.36%, 11.75%, and 7.39% for 2012, 2011, and 2010, respectively.

Impairment of Long-Lived Assets and Intangibles

The Company evaluates long-lived assets for impairment when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. The determination of whether an impairment has occurred is based on either a specific regulatory disallowance or an estimate of undiscounted future cash flows attributable to the assets, as compared with the carrying value of the assets. If an impairment has occurred, the amount of the impairment recognized is determined by either the amount of regulatory disallowance or by estimating the fair value of the assets and recording a loss if the carrying value is greater

than the fair value. For assets identified as held for sale, the carrying value is compared to the estimated fair value less the cost to sell in order to determine if an impairment loss is required. Until the assets are disposed of, their estimated fair value is re-evaluated when circumstances or events change.

Property Damage Reserve

The Company accrues for the cost of repairing damages from major storms and other uninsured property damages, including uninsured damages to transmission and distribution facilities, generation facilities, and other property. The costs of such damage are charged to the reserve. The Florida PSC approved annual accrual to the property damage reserve is $3.5 million, with a target level for the reserve between $48.0 million and $55.0 million. The Florida PSC also authorized the Company to make additional accruals above the $3.5 million at the Company's discretion. The Company accrued total expenses of $3.5 million in each of 2012, 2011, and 2010. As of December 31, 2012 and 2011, the balance in the Company's property damage reserve totaled approximately $32.0 million and $30.5 million, respectively, which is included in deferred liabilities in the balance sheets.

When the property damage reserve is inadequate to cover the cost of major storms, the Florida PSC can authorize a storm cost recovery surcharge to be applied to customer bills. Such a surcharge was authorized in 2005 after Hurricane Ivan in 2004 and was extended by a 2006 Florida PSC order approving a stipulation to address costs incurred as a result of Hurricanes Dennis and Katrina in 2005. Under the 2006 Florida PSC order, if the Company incurs cumulative costs for storm recovery activities in excess of $10 million during any calendar year, the Company would be permitted to file a streamlined formal request for an interim surcharge. Any interim surcharge would provide for the recovery, subject to refund, of up to 80% of the claimed costs for storm recovery activities. The Company would then petition the Florida PSC for full recovery through a final or non-interim surcharge or other cost recovery mechanism. After the effective date of new base rates, the Company will retain the right to request relief on an expedited basis from the Florida PSC without the thresholds set forth in the stipulation.

Injuries and Damages Reserve

The Company is subject to claims and lawsuits arising in the ordinary course of business. As permitted by the Florida PSC, the Company accrues for the uninsured costs of injuries and damages by charges to income amounting to $1.6 million annually. The Florida PSC has also given the Company the flexibility to increase its annual accrual above $1.6 million to the extent the balance in the reserve does not exceed $2 million and to defer expense recognition of liabilities greater than the balance in the reserve. The cost of settling claims is charged to the reserve. The injuries and damages reserve was $3.1 million and $2.7 million at December 31, 2012 and 2011, respectively. For 2012, $1.6 million and $1.5 million are included in current liabilities and deferred credits and other liabilities in the balance sheets, respectively. For 2011, $1.6 million and $1.1 million are included in current liabilities and deferred credits and other liabilities in the balance sheets, respectively. There were no liabilities in excess of the reserve balance at December 31, 2012 and 2011.

Cash and Cash Equivalents

For purposes of the financial statements, temporary cash investments are considered cash equivalents. Temporary cash investments are securities with original maturities of 90 days or less.

Materials and Supplies

Generally, materials and supplies include the average cost of transmission, distribution, and generating plant materials. Materials are charged to inventory when purchased and then expensed or capitalized to plant, as appropriate, at weighted average cost when installed.

Fuel Inventory

Fuel inventory includes the average cost of oil, natural gas, coal, transportation, and emissions allowances. Fuel is charged to inventory when purchased and then expensed, at weighted average cost, as used. Fuel expense and emissions allowance costs are recovered by the Company through the fuel cost recovery and environmental cost recovery rates, respectively, approved annually by the Florida PSC. Emissions allowances granted by the Environmental Protection Agency (EPA) are included in inventory at zero cost.

Financial Instruments

The Company uses derivative financial instruments to limit exposure to fluctuations in interest rates, the prices of certain fuel purchases, and electricity purchases and sales. All derivative financial instruments are recognized as either assets or liabilities (included in "Other" or shown separately as "Risk Management Activities") and are measured at fair value. See Note 9 for additional information. Substantially all of the Company's bulk energy purchases and sales contracts that meet the definition of a

derivative are excluded from fair value accounting requirements because they qualify for the "normal" scope exception, and are accounted for under the accrual method. Other derivative contracts qualify as cash flow hedges of anticipated transactions or are recoverable through the Florida PSC approved fuel hedging program. This results in the deferral of related gains and losses in OCI or regulatory assets and liabilities, respectively, until the hedged transactions occur. Any ineffectiveness arising from cash flow hedges is recognized currently in net income. Other derivative contracts are marked to market through current period income and are recorded on a net basis in the statements of income. See Note 10 for additional information.

The Company does not offset fair value amounts recognized for multiple derivative instruments executed with the same counterparty under a master netting arrangement. Additionally, the Company had no outstanding collateral repayment obligations or rights to reclaim collateral arising from derivative instruments recognized at December 31, 2012.

The Company is exposed to losses related to financial instruments in the event of counterparties' nonperformance. The Company has established controls to determine and monitor the creditworthiness of counterparties in order to mitigate the Company's exposure to counterparty credit risk.

Comprehensive Income

The objective of comprehensive income is to report a measure of all changes in common stock equity of an enterprise that result from transactions and other economic events of the period other than transactions with owners. Comprehensive income consists of net income, changes in the fair value of qualifying cash flow hedges, and reclassifications for amounts included in net income.

2. RETIREMENT BENEFITS

The Company has a defined benefit, trusteed, pension plan covering substantially all employees. This qualified pension plan is funded in accordance with requirements of the Employee Retirement Income Security Act of 1974, as amended (ERISA). In December 2012, the Company contributed $13.4 million to the qualified pension plan. No mandatory contributions to the qualified pension plan are anticipated for the year ending December 31, 2013. The Company also provides certain defined benefit pension plans for a selected group of management and highly compensated employees. Benefits under these non-qualified pension plans are funded on a cash basis. In addition, the Company provides certain medical care and life insurance benefits for retired employees through other postretirement benefit plans. The Company funds its other postretirement trusts to the extent required by the FERC. For the year ending December 31, 2013, no other postretirement trust contributions are expected.

Actuarial Assumptions

The weighted average rates assumed in the actuarial calculations used to determine both the benefit obligations as of the measurement date and the net periodic costs for the pension and other postretirement benefit plans for the following year are presented below. Net periodic benefit costs were calculated in 2009 for the 2010 plan year using discount rates for the pension plans and the other postretirement benefit plans of 5.93% and 5.84%, respectively, and an annual salary increase of 4.18%.

	2012	2011	2010
Discount rate:			
Pension plans	**4.27%**	4.98%	5.53%
Other postretirement benefit plans	**4.06**	4.88	5.41
Annual salary increase	**3.59**	3.84	3.84
Long-term return on plan assets:			
Pension plans	**8.20**	8.45	8.45
Other postretirement benefit plans	**8.02**	8.11	8.18

The Company estimates the expected rate of return on pension plan and other postretirement benefit plan assets using a financial model to project the expected return on each current investment portfolio. The analysis projects an expected rate of return on each of seven different asset classes in order to arrive at the expected return on the entire portfolio relying on each trust's target asset allocation and reasonable capital market assumptions. The financial model is based on four key inputs: anticipated returns by asset class (based in part on historical returns), each trust's target asset allocation, an anticipated inflation rate, and the projected impact of a periodic rebalancing of each trust's portfolio.

An additional assumption used in measuring the accumulated other postretirement benefit obligations (APBO) is the weighted average medical care cost trend rate. The weighted average medical care cost trend rates used in measuring the APBO as of December 31, 2012 were as follows:

	Initial Cost Trend Rate	Ultimate Cost Trend Rate	Year That Ultimate Rate Is Reached
Pre-65	8.00%	5.00%	2020
Post-65 medical	6.00	5.00	2020
Post-65 prescription	6.00	5.00	2020

An annual increase or decrease in the assumed medical care cost trend rate of 1% would affect the APBO and the service and interest cost components at December 31, 2012 as follows:

	1 Percent Increase	1 Percent Decrease
	(in thousands)	
Benefit obligation	$ 3,399	$ (2,897)
Service and interest costs	198	(169)

Pension Plans

The total accumulated benefit obligation for the pension plans was $371 million at December 31, 2012 and $321 million at December 31, 2011. Changes in the projected benefit obligations and the fair value of plan assets during the plan years ended December 31, 2012 and 2011 were as follows:

	2012	2011
	(in thousands)	
Change in benefit obligation		
Benefit obligation at beginning of year	$ **352,834**	$ 316,286
Service cost	**9,101**	8,431
Interest cost	**17,199**	17,074
Benefits paid	**(14,046)**	(13,807)
Plan amendments	**426**	—
Actuarial loss	**47,987**	24,850
Balance at end of year	**413,501**	352,834
Change in plan assets		
Fair value of plan assets at beginning of year	**304,324**	307,828
Actual return on plan assets	**45,762**	9,552
Employer contributions	**14,220**	751
Benefits paid	**(14,046)**	(13,807)
Fair value of plan assets at end of year	**350,260**	304,324
Accrued liability	$ **(63,241)**	$ (48,510)

At December 31, 2012, the projected benefit obligations for the qualified and non-qualified pension plans were $393 million and $20 million, respectively. All pension plan assets are related to the qualified pension plan.

Amounts recognized in the balance sheets at December 31, 2012 and 2011 related to the Company's pension plans consist of the following:

	2012	2011
	(in thousands)	
Other regulatory assets	**$ 139,261**	$ 115,853
Current liabilities, other	**(855)**	(794)
Employee benefit obligations	**(62,386)**	(47,716)

Presented below are the amounts included in regulatory assets at December 31, 2012 and 2011 related to the defined benefit pension plans that had not yet been recognized in net periodic pension cost along with the estimated amortization of such amounts for 2013.

	2012	2011	Estimated Amortization in 2013
		(in thousands)	
Prior service cost	**$ 5,565**	$ 6,402	**$ 1,164**
Net (gain) loss	**133,696**	109,451	**8,385**
Other regulatory assets	**$ 139,261**	$ 115,853	

The changes in the balance of regulatory assets related to the defined benefit pension plans for the years ended December 31, 2012 and 2011 are presented in the following table:

	Regulatory Assets
	(in thousands)
Balance at December 31, 2010	$ 75,096
Net (gain) loss	42,531
Change in prior service costs	—
Reclassification adjustments:	
Amortization of prior service costs	(1,262)
Amortization of net gain (loss)	(512)
Total reclassification adjustments	(1,774)
Total change	40,757
Balance at December 31, 2011	$ 115,853
Net (gain) loss	**28,157**
Change in prior service costs	**426**
Reclassification adjustments:	
Amortization of prior service costs	**(1,262)**
Amortization of net gain (loss)	**(3,913)**
Total reclassification adjustments	**(5,175)**
Total change	**23,408**
Balance at December 31, 2012	**$ 139,261**

Components of net periodic pension cost were as follows:

	2012	2011	2010
		(in thousands)	
Service cost	**$ 9,101**	$ 8,431	$ 7,853
Interest cost	**17,199**	17,074	17,305
Expected return on plan assets	**(25,932)**	(27,232)	(24,695)
Recognized net (gain) loss	**3,913**	512	398
Net amortization	**1,262**	1,262	1,302
Net periodic pension cost	**$ 5,543**	$ 47	$ 2,163

Net periodic pension cost is the sum of service cost, interest cost, and other costs netted against the expected return on plan assets. The expected return on plan assets is determined by multiplying the expected rate of return on plan assets and the market-related value of plan assets. In determining the market-related value of plan assets, the Company has elected to amortize changes in the market value of all plan assets over five years rather than recognize the changes immediately. As a result, the accounting value of plan assets that is used to calculate the expected return on plan assets differs from the current fair value of the plan assets.

Future benefit payments reflect expected future service and are estimated based on assumptions used to measure the projected benefit obligation for the pension plans. At December 31, 2012, estimated benefit payments were as follows:

	Benefit Payments
	(in thousands)
2013	$ 15,767
2014	16,606
2015	17,427
2016	18,272
2017	19,383
2018 to 2022	113,108

Other Postretirement Benefits

Changes in the APBO and in the fair value of plan assets during the plan years ended December 31, 2012 and 2011 were as follows:

	2012	2011
	(in thousands)	
Change in benefit obligation		
Benefit obligation at beginning of year	**$ 70,923**	$ 69,617
Service cost	**1,167**	1,132
Interest cost	**3,367**	3,658
Benefits paid	**(3,854)**	(4,189)
Actuarial loss	**3,468**	292
Plan amendments	**—**	—
Retiree drug subsidy	**324**	413
Balance at end of year	**75,395**	70,923
Change in plan assets		
Fair value of plan assets at beginning of year	**14,978**	15,697
Actual return on plan assets	**2,131**	514
Employer contributions	**2,648**	2,543
Benefits paid	**(3,530)**	(3,776)
Fair value of plan assets at end of year	**16,227**	14,978
Accrued liability	**$ (59,168)**	$ (55,945)

Amounts recognized in the balance sheets at December 31, 2012 and 2011 related to the Company's other postretirement benefit plans consist of the following:

	2012	2011
	(in thousands)	
Regulatory assets	**$ 2,169**	$ 239
Current liabilities, other	**(661)**	(624)
Employee benefit obligations	**(58,507)**	(55,321)

Presented below are the amounts included in regulatory assets at December 31, 2012 and 2011 related to the other postretirement benefit plans that had not yet been recognized in net periodic other postretirement benefit cost along with the estimated amortization of such amounts for 2013.

	2012	2011	Estimated Amortization in 2013
		(in thousands)	
Prior service cost	**$ 324**	$ 510	**$ 186**
Net (gain) loss	**1,845**	(464)	**—**
Transition obligation	**—**	193	**—**
Regulatory assets (liabilities)	**$ 2,169**	$ 239	

The changes in the balance of regulatory assets and regulatory liabilities related to the other postretirement benefit plans for the plan years ended December 31, 2012 and 2011 are presented in the following table:

	Regulatory Assets	Regulatory Liabilities
	(in thousands)	
Balance at December 31, 2010	$ —	$ (166)
Net (gain) loss	635	166
Change in prior service costs/transition obligation	—	—
Reclassification adjustments:		
Amortization of transition obligation	(257)	—
Amortization of prior service costs	(186)	—
Amortization of net gain (loss)	47	—
Total reclassification adjustments	(396)	—
Total change	239	166
Balance at December 31, 2011	$ 239	$ —
Net (gain) loss	**2,309**	—
Change in prior service costs/transition obligation	—	—
Reclassification adjustments:		
Amortization of transition obligation	**(193)**	—
Amortization of prior service costs	**(186)**	—
Amortization of net gain (loss)	—	—
Total reclassification adjustments	**(379)**	—
Total change	**1,930**	—
Balance at December 31, 2012	**$ 2,169**	**$ —**

Components of the other postretirement benefit plans' net periodic cost were as follows:

	2012	2011	2010
		(in thousands)	
Service cost	**$ 1,167**	$ 1,132	$ 1,304
Interest cost	**3,367**	3,658	4,121
Expected return on plan assets	**(1,311)**	(1,445)	(1,481)
Net amortization	**379**	396	406
Net postretirement cost	**$ 3,602**	$ 3,741	$ 4,350

Future benefit payments, including prescription drug benefits, reflect expected future service and are estimated based on assumptions used to measure the APBO for the other postretirement benefit plans. Estimated benefit payments are reduced by drug subsidy receipts expected as a result of the Medicare Prescription Drug, Improvement, and Modernization Act of 2003 as follows:

	Benefit Payments	Subsidy Receipts	Total
		(in thousands)	
2013	$ 4,473	$ (488)	$ 3,985
2014	4,707	(537)	4,170
2015	4,903	(589)	4,314
2016	5,117	(643)	4,474
2017	5,211	(705)	4,506
2018 to 2022	26,913	(3,804)	23,109

Benefit Plan Assets

Pension plan and other postretirement benefit plan assets are managed and invested in accordance with all applicable requirements, including ERISA and the Internal Revenue Code of 1986, as amended (Internal Revenue Code). The Company's investment policies for both the pension plan and the other postretirement benefit plans cover a diversified mix of assets, including equity and fixed income securities, real estate, and private equity. Derivative instruments are used primarily to gain efficient exposure to the various asset classes and as hedging tools. The Company minimizes the risk of large losses primarily through diversification but also monitors and manages other aspects of risk.

The composition of the Company's pension plan and other postretirement benefit plan assets as of December 31, 2012 and 2011, along with the targeted mix of assets for each plan, is presented below:

	Target	2012	2011
Pension plan assets:			
Domestic equity	26%	**28%**	29%
International equity	25	**24**	25
Fixed income	23	**27**	23
Special situations	3	**1**	—
Real estate investments	14	**13**	14
Private equity	9	**7**	9
Total	100%	**100%**	100%
Other postretirement benefit plan assets:			
Domestic equity	25%	**27%**	28%
International equity	24	**23**	24
Domestic fixed income	25	**29**	26
Special situations	3	**1**	—
Real estate investments	14	**13**	13
Private equity	9	**7**	9
Total	100%	**100%**	100%

The investment strategy for plan assets related to the Company's qualified pension plan is to be broadly diversified across major asset classes. The asset allocation is established after consideration of various factors that affect the assets and liabilities of the pension plan including, but not limited to, historical and expected returns, volatility, correlations of asset classes, the current level of assets and liabilities, and the assumed growth in assets and liabilities. Because a significant portion of the liability of the pension plan is long-term in nature, the assets are invested consistent with long-term investment expectations for return and risk. To manage the actual asset class exposures relative to the target asset allocation, the Company employs a formal rebalancing program. As additional risk management, external investment managers and service providers are subject to written guidelines to ensure appropriate and prudent investment practices.

Investment Strategies

Detailed below is a description of the investment strategies for each major asset category for the pension and other postretirement benefit plans disclosed above:

- ***Domestic equity.*** A mix of large and small capitalization stocks with generally an equal distribution of value and growth attributes, managed both actively and through passive index approaches.
- ***International equity.*** A mix of growth stocks and value stocks with both developed and emerging market exposure, managed both actively and through passive index approaches.
- ***Fixed income.*** A mix of domestic and international bonds.
- ***Special situations.*** Investments in opportunistic strategies with the objective of diversifying and enhancing returns and exploiting short-term inefficiencies as well as investments in promising new strategies of a longer-term nature.
- ***Real estate investments.*** Investments in traditional private market, equity-oriented investments in real properties (indirectly through pooled funds or partnerships) and in publicly traded real estate securities.
- ***Private equity.*** Investments in private partnerships that invest in private or public securities typically through privately-negotiated and/or structured transactions, including leveraged buyouts, venture capital, and distressed debt.

Benefit Plan Asset Fair Values

Following are the fair value measurements for the pension plan and the other postretirement benefit plan assets as of December 31, 2012 and 2011. The fair values presented are prepared in accordance with GAAP. For purposes of determining the fair value of the pension plan and other postretirement benefit plan assets and the appropriate level designation, management relies on information provided by the plan's trustee. This information is reviewed and evaluated by management with changes made to the trustee information as appropriate.

Valuation methods of the primary fair value measurements disclosed in the following tables are as follows:

- **Investments in equity securities:** Investments in equity securities such as common stocks, American depositary receipts, and real estate investment trusts that trade on a public exchange are classified as Level 1 investments and are valued at the closing price in the active market. Equity investments with unpublished prices (i.e. pooled funds) are valued as Level 2, when the underlying holdings used to value the investment are comprised of Level 1 or Level 2 equity securities.
- **Investments in fixed income securities:** Investments in fixed income securities are generally classified as Level 2 investments and are valued based on prices reported in the market place. Additionally, the value of fixed income securities takes into consideration certain items such as broker quotes, spreads, yield curves, interest rates, and discount rates that apply to the term of a specific instrument.
- **Investments in private equity and real estate:** Investments in private equity and real estate are generally classified as Level 3 as the underlying assets typically do not have observable inputs. The fund manager values the assets using various inputs and techniques depending on the nature of the underlying investments. In the case of private equity, techniques may include purchase multiples for comparable transactions, comparable public company trading multiples, and discounted cash flow analysis. Real estate managers generally use prevailing market capitalization rates, recent sales of comparable investments, and independent third-party appraisals to value underlying real estate investments. The fair value of partnerships is determined by aggregating the value of the underlying assets.

The fair values of pension plan assets as of December 31, 2012 and 2011 are presented below. These fair value measurements exclude cash, receivables related to investment income, pending investments sales, and payables related to pending investment purchases. Assets that are considered special situations investments, primarily real estate investments and private equities, are presented in the tables below based on the nature of the investment.

	Fair Value Measurements Using			
As of December 31, 2012:	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Total**
		(in thousands)		
Assets:				
Domestic equity*	$ 51,215	$ 29,499	$ —	$ 80,714
International equity*	40,166	43,120	—	83,286
Fixed income:				
U.S. Treasury, government, and agency bonds	—	22,724	—	22,724
Mortgage- and asset-backed securities	—	5,594	—	5,594
Corporate bonds	—	38,534	139	38,673
Pooled funds	—	17,581	—	17,581
Cash equivalents and other	208	24,148	—	24,356
Real estate investments	11,362	—	37,039	48,401
Private equity	—	—	26,129	26,129
Total	$ 102,951	$ 181,200	$ 63,307	$ 347,458

* Level 1 securities consist of actively traded stocks while Level 2 securities consist of pooled funds. Management believes that the portfolio is well-diversified with no significant concentrations of risk.

	Fair Value Measurements Using			
As of December 31, 2011:	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Total**
		(in thousands)		
Assets:				
Domestic equity*	$ 51,686	$ 23,857	$ —	$ 75,543
International equity*	53,130	15,223	—	68,353
Fixed income:				
U.S. Treasury, government, and agency bonds	—	19,375	—	19,375
Mortgage- and asset-backed securities	—	6,047	—	6,047
Corporate bonds	—	37,274	120	37,394
Pooled funds	—	16,998	—	16,998
Cash equivalents and other	30	6,228	—	6,258
Real estate investments	9,838	—	34,989	44,827
Private equity	—	—	26,053	26,053
Total	$ 114,684	$ 125,002	$ 61,162	$ 300,848

* Level 1 securities consist of actively traded stocks while Level 2 securities consist of pooled funds. Management believes that the portfolio is well-diversified with no significant concentrations of risk.

Changes in the fair value measurement of the Level 3 items in the pension plan assets valued using significant unobservable inputs for the years ended December 31, 2012 and 2011 were as follows:

	2012		2011	
	Real Estate Investments	Private Equity	Real Estate Investments	Private Equity
	(in thousands)			
Beginning balance	$ 34,989	$ 26,053	$ 30,355	$ 28,727
Actual return on investments:				
Related to investments held at year end	1,918	44	3,021	(538)
Related to investments sold during the year	132	1,396	896	1,941
Total return on investments	2,050	1,440	3,917	1,403
Purchases, sales, and settlements	—	(1,364)	717	(4,077)
Transfers into/out of Level 3	—	—	—	—
Ending balance	$ 37,039	$ 26,129	$ 34,989	$ 26,053

The fair values of other postretirement benefit plan assets as of December 31, 2012 and 2011 are presented below. These fair value measurements exclude cash, receivables related to investment income, pending investments sales, and payables related to pending investment purchases. Assets that are considered special situations investments, primarily real estate investments and private equities, are presented in the tables below based on the nature of the investment.

	Fair Value Measurements Using			
As of December 31, 2012:	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
		(in thousands)		
Assets:				
Domestic equity*	$ 2,290	$ 1,319	$ —	$ 3,609
International equity*	1,795	1,928	—	3,723
Fixed income:				
U.S. Treasury, government, and agency bonds	—	1,016	—	1,016
Mortgage- and asset-backed securities	—	250	—	250
Corporate bonds	—	1,722	6	1,728
Pooled funds	—	1,298	—	1,298
Cash equivalents and other	9	1,078	—	1,087
Real estate investments	508	—	1,667	2,175
Private equity	—	15	1,155	1,170
Total	$ 4,602	$ 8,626	$ 2,828	$ 16,056

* Level 1 securities consist of actively traded stocks while Level 2 securities consist of pooled funds. Management believes that the portfolio is well-diversified with no significant concentrations of risk.

As of December 31, 2011:	Fair Value Measurements Using: Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
		(in thousands)		
Assets:				
Domestic equity*	$ 2,445	$ 1,128	$ —	$ 3,573
International equity*	2,511	719	—	3,230
Fixed income:				
U.S. Treasury, government, and agency bonds	—	918	—	918
Mortgage- and asset-backed securities	—	286	—	286
Corporate bonds	—	1,761	—	1,761
Pooled funds	—	1,328	—	1,328
Cash equivalents and other	1	295	—	296
Real estate investments	466	—	1,657	2,123
Private equity	—	—	1,232	1,232
Total	$ 5,423	$ 6,435	$ 2,889	$ 14,747

* Level 1 securities consist of actively traded stocks while Level 2 securities consist of pooled funds. Management believes that the portfolio is well-diversified with no significant concentrations of risk.

Changes in the fair value measurement of the Level 3 items in the other postretirement benefit plan assets valued using significant unobservable inputs for the years ended December 31, 2012 and 2011 were as follows:

	2012		2011	
	Real Estate Investments	Private Equity	Real Estate Investments	Private Equity
		(in thousands)		
Beginning balance	**$ 1,657**	**$ 1,232**	$ 1,452	$ 1,375
Actual return on investments:				
Related to investments held at year end	**107**	**(1)**	129	(26)
Related to investments sold during the year	**6**	**80**	42	77
Total return on investments	**113**	**79**	171	51
Purchases, sales, and settlements	**(103)**	**(156)**	34	(194)
Transfers into/out of Level 3	**—**	**—**	—	—
Ending balance	**$ 1,667**	**$ 1,155**	$ 1,657	$ 1,232

Employee Savings Plan

The Company also sponsors a 401(k) defined contribution plan covering substantially all employees. The Company provides an 85% matching contribution on up to 6% of an employee's base salary. Total matching contributions made to the plan for 2012, 2011, and 2010 were $4.0 million, $3.7 million, and $3.6 million, respectively.

3. CONTINGENCIES AND REGULATORY MATTERS

General Litigation Matters

The Company is subject to certain claims and legal actions arising in the ordinary course of business. In addition, the Company's business activities are subject to extensive governmental regulation related to public health and the environment, such as regulation of air emissions and water discharges. Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements such as air quality and water standards, has increased generally throughout the U.S. In particular, personal injury, property damage, and other claims for damages alleged to have been caused by carbon dioxide and other emissions, coal combustion byproducts, and alleged exposure to hazardous materials, and/or requests for injunctive relief in connection with such matters, have become more frequent. The ultimate outcome of such pending or potential litigation against the Company cannot be predicted at this time; however, for current proceedings not specifically reported herein, management does not anticipate that the ultimate liabilities, if any, arising from such current proceedings would have a material effect on the Company's financial statements.

Environmental Matters

New Source Review Actions

In 1999, the EPA brought a civil action in the U.S. District Court for the Northern District of Georgia against certain Southern Company subsidiaries, including Alabama Power and Georgia Power, alleging that these subsidiaries had violated the New Source Review (NSR) provisions of the Clean Air Act and related state laws at certain coal-fired generating facilities. The EPA alleged NSR violations at five coal-fired generating facilities operated by Alabama Power and three coal-fired generating facilities operated by Georgia Power, including a unit co-owned by the Company. The civil action sought penalties and injunctive relief, including an order requiring installation of the best available control technology at the affected units. These actions were filed concurrently with the issuance of notices of violation of the NSR provisions to the Company with respect to the Company's Plant Crist. The case against Georgia Power (including claims related to the unit co-owned by the Company) was administratively closed in 2001 and has not been reopened. After Alabama Power was dismissed from the original action, the EPA filed a separate action in 2001 against Alabama Power in the U.S. District Court for the Northern District of Alabama.

The Company believes it complied with applicable laws and regulations in effect at the time the work in question took place. The Clean Air Act authorizes maximum civil penalties of $25,000 to $37,500 per day, per violation, depending on the date of the alleged violation. An adverse outcome could require substantial capital expenditures that cannot be determined at this time and could possibly require payment of substantial penalties. Such expenditures could affect future results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates. The ultimate outcome of this matter cannot be determined at this time.

Climate Change Litigation

Kivalina Case

In 2008, the Native Village of Kivalina and the City of Kivalina filed a lawsuit in the U.S. District Court for the Northern District of California against several electric utilities (including Southern Company), several oil companies, and a coal company. The plaintiffs allege that the village is being destroyed by erosion allegedly caused by global warming that the plaintiffs attribute to emissions of greenhouse gases by the defendants. The plaintiffs assert claims for public and private nuisance and contend that some of the defendants (including Southern Company) acted in concert and are therefore jointly and severally liable for the plaintiffs' damages. The suit seeks damages for lost property values and for the cost of relocating the village, which is alleged to be $95 million to $400 million. In 2009, the U.S. District Court for the Northern District of California granted the defendants' motions to dismiss the case. On September 21, 2012, the U.S. Court of Appeals for the Ninth Circuit upheld the U.S. District Court for the Northern District of California's dismissal of the case. On November 27, 2012, the U.S. Court of Appeals for the Ninth Circuit denied the plaintiffs' request for review of the decision. On February 25, 2013, the plaintiffs filed a petition for writ of certiorari with the U.S. Supreme Court. Southern Company believes that these claims are without merit. While Southern Company believes the likelihood of loss is remote based on existing case law, it is not possible to predict with certainty whether the Company will incur any liability in connection with this matter. The ultimate outcome of this matter cannot be determined at this time.

Hurricane Katrina Case

In 2005, immediately following Hurricane Katrina, a lawsuit was filed in the U.S. District Court for the Southern District of Mississippi by Ned Comer on behalf of Mississippi residents seeking recovery for property damage and personal injuries caused by Hurricane Katrina. In 2006, the plaintiffs amended the complaint to include Southern Company and many other electric utilities, oil

companies, chemical companies, and coal producers. The plaintiffs allege that the defendants contributed to climate change, which contributed to the intensity of Hurricane Katrina. In 2007, the U.S. District Court for the Southern District of Mississippi dismissed the case. On appeal to the U.S. Court of Appeals for the Fifth Circuit, a three-judge panel reversed the U.S. District Court for the Southern District of Mississippi, holding that the case could proceed, but on rehearing, the full U.S. Court of Appeals for the Fifth Circuit dismissed the plaintiffs' appeal, resulting in reinstatement of the decision of the U.S. District Court for the Southern District of Mississippi in favor of the defendants. In May 2011, the plaintiffs filed an amended version of their class action complaint, arguing that the earlier dismissal was on procedural grounds and under Mississippi law the plaintiffs have a right to re-file. The amended complaint was also filed against numerous chemical, coal, oil, and utility companies, including the Company. On March 20, 2012, the U.S. District Court for the Southern District of Mississippi dismissed the plaintiffs' amended complaint. On April 16, 2012, the plaintiffs appealed the case to the U.S. Court of Appeals for the Fifth Circuit. The Company believes that these claims are without merit. While the Company believes the likelihood of loss is remote based on existing case law, it is not possible to predict with certainty whether the Company will incur any liability in connection with this matter. The ultimate outcome of this matter cannot be determined at this time.

Environmental Remediation

The Company must comply with environmental laws and regulations that cover the handling and disposal of waste and releases of hazardous substances. Under these various laws and regulations, the Company may also incur substantial costs to clean up properties. The Company received authority from the Florida PSC to recover approved environmental compliance costs through the environmental cost recovery clause. The Florida PSC reviews costs and adjusts rates up or down annually.

The Company recognizes a liability for environmental remediation costs only when it determines a loss is probable. At December 31, 2012, the Company's environmental remediation liability included estimated costs of environmental remediation projects of approximately $60.5 million. For 2012, approximately $2.6 million was included in under recovered regulatory clause revenues and other current liabilities, and approximately $57.9 million was included in other regulatory assets, deferred and other deferred credits and liabilities. These estimated costs relate to site closure criteria by the Florida Department of Environmental Protection (FDEP) for potential impacts to soil and groundwater from herbicide applications at the Company's substations. The schedule for completion of the remediation projects will be subject to FDEP approval. The projects have been approved by the Florida PSC for recovery through the Company's environmental cost recovery clause; therefore, there was no impact on net income as a result of these liabilities.

The final outcome of these matters cannot be determined at this time. However, based on the currently known conditions at these sites and the nature and extent of activities relating to these sites, the Company does not believe that additional liabilities, if any, at these sites would be material to the Company's financial statements.

Retail Regulatory Matters

The Company's rates and charges for service to retail customers are subject to the regulatory oversight of the Florida PSC. The Company's rates are a combination of base rates and several separate cost recovery clauses for specific categories of costs. These separate cost recovery clauses address such items as fuel and purchased energy costs, purchased power capacity costs, energy conservation and demand side management programs, and the costs of compliance with environmental laws and regulations. Costs not addressed through one of the specific cost recovery clauses are recovered through the Company's base rates.

Retail Base Rate Case

On March 12, 2012, the Florida PSC approved an increase in retail base rates and charges of $64 million effective April 11, 2012. The amount of the increase includes the previously approved $38.5 million interim retail rate increase implemented in September 2011. The Florida PSC's decision on the amount of the increase also included a determination that none of the base rate revenues collected on an interim basis would be refunded. The Company's authorized retail ROE is a range of 9.25% to 11.25% with new retail base rates set at the midpoint retail ROE of 10.25%. In addition, the Florida PSC also approved a step increase to the Company's retail base rates and charges of $4 million effective in January 2013.

Cost Recovery Clauses

On November 5, 2012, the Florida PSC approved the Company's annual rate clause requests for its fuel, purchased power capacity, conservation, and environmental compliance cost recovery factors for 2013. The net effect of the approved changes is a 1.9% rate increase for residential customers using 1,000 KWHs per month.

Revenues for all cost recovery clauses, as recorded on the financial statements, are adjusted for differences in actual recoverable costs and amounts billed in current regulated rates. Accordingly, changes in the billing factor for fuel and purchased power will have no significant effect on the Company's revenues or net income, but will affect annual cash flow. The recovery provisions for environmental compliance and energy conservation include related expenses and a return on net average investment.

Fuel Cost Recovery

The Company has established fuel cost recovery rates as approved by the Florida PSC. If, at any time during the year, the projected year-end fuel cost over or under recovery balance exceeds 10% of the projected fuel revenue applicable for the period, the Company is required to notify the Florida PSC and indicate if an adjustment to the fuel cost recovery factor is being requested. On February 14, 2012, the Florida PSC approved a reduction to the fuel cost recovery factors starting in March 2012. The effect of the approved change was a 2.7% decrease for residential customers using 1,000 KWHs per month. On June 19, 2012, the Florida PSC approved an additional decrease in the Company's fuel rates lowering the 1,000 KWH residential bill 7.8% to reduce annual billings by approximately $58.8 million effective July 2, 2012.

The increase in the fuel cost over recovered balance during 2012 was primarily due to lower than expected fuel costs and purchased power energy expenses. At December 31, 2012 and 2011, the over recovered fuel balance was approximately $17.1 million and $9.9 million, respectively, which is included in other regulatory liabilities, current in the balance sheets.

Purchased Power Capacity Recovery

The Company has established purchased power capacity recovery cost rates as approved by the Florida PSC. If the projected year-end purchased power capacity cost over or under recovery balance exceeds 10% of the projected purchased power capacity revenue applicable for the period, the Company is required to notify the Florida PSC and indicate if an adjustment to the purchased power capacity cost recovery factor is being requested.

At December 31, 2012, the Company had an under recovered purchased power capacity balance of approximately $0.8 million, which is included in under recovered regulatory clause revenues in the balance sheets. At December 31, 2011, the Company had an over recovered purchased power capacity balance of approximately $8.0 million, which is included in other regulatory liabilities, current in the balance sheets.

Environmental Cost Recovery

The Florida Legislature adopted legislation for an environmental cost recovery clause, which allows an electric utility to petition the Florida PSC for recovery of prudent environmental compliance costs that are not being recovered through base rates or any other recovery mechanism. Such environmental costs include operations and maintenance expenses, emissions allowance expense, depreciation, and a return on net average investment. This legislation also allows recovery of costs incurred as a result of an agreement between the Company and the FDEP for the purpose of ensuring compliance with ozone ambient air quality standards adopted by the EPA.

In 2007, the Florida PSC voted to approve a stipulation among the Company, the Office of Public Counsel, and the Florida Industrial Power Users Group regarding the Company's plan for complying with certain federal and state regulations addressing air quality. The Company's environmental compliance plan as filed in 2007 contemplated implementation of specific projects identified in the plan from 2007 through 2018. The stipulation covers all elements of the original plan that were committed for implementation at the time of the stipulation. The Florida PSC's approval of the stipulation also required the Company to file annual updates to the plan and outlined a process for approval of additional elements in the plan when they became committed projects. In the 2010 update filing, the Company identified several elements of the updated plan that the Company had decided to implement. Following the process outlined in the original approved stipulation, these additional projects were approved by the Florida PSC later in 2010. The Florida PSC acknowledged that the costs of the approved projects associated with the Company's Clean Air Interstate Rule and Clean Air Visibility Rule compliance plans are eligible for recovery through the environmental cost recovery clause.

Annually, the Company seeks recovery of projected costs including any true-up amounts from prior periods. At December 31, 2012, the under recovered environmental balance was approximately $1.9 million, which is included in under recovered regulatory clause revenues in the balance sheets. At December 31, 2011, the over recovered environmental balance was approximately $10.0 million, which is included in other regulatory liabilities, current in the balance sheets.

On April 3, 2012, the Mississippi PSC approved Mississippi Power's request for a certificate of public convenience and necessity to construct a flue gas desulfurization system (scrubber) on Plant Daniel Units 1 and 2. On May 3, 2012, the Sierra Club filed a notice of appeal of the order with the Chancery Court of Harrison County, Mississippi. These units are jointly owned by Mississippi Power and the Company, with 50% ownership each. The estimated total cost of the project is approximately $660 million, excluding AFUDC, and it is scheduled for completion in December 2015. The Company's portion of the cost is expected to be recovered through the environmental cost recovery clause. The ultimate outcome of this matter cannot be determined at this time.

Energy Conservation Cost Recovery

Every five years, the Florida PSC establishes new numeric conservation goals covering a 10-year period for utilities to reduce annual energy and seasonal peak demand using demand-side management (DSM) programs. After the goals are established, utilities develop plans and programs to meet the approved goals. The costs for these programs are recovered through rates established annually in the energy conservation cost recovery (ECCR) clause.

The most recent goal setting process established new DSM goals for the period 2010 through 2019. The new goals are significantly higher than the goals established in the previous five-year cycle due to a change in the cost-effectiveness test on which the Florida PSC relies to set the goals. The DSM program standards were approved in April 2011, which allow the Company to implement its DSM programs designed to meet the new goals. Several of these new programs were implemented in June 2011 and the costs related to these programs are reflected in the 2012 ECCR factor approved by the Florida PSC. Higher cost recovery rates and achievement of the new DSM goals may result in reduced sales of electricity which could negatively impact results of operations, cash flows, and financial condition if base rates cannot be adjusted on a timely basis.

At December 31, 2012 and 2011, the under recovered energy conservation balance was approximately $0.8 million and $3.1 million, respectively, which is included in under recovered regulatory clause revenues in the balance sheets.

4. JOINT OWNERSHIP AGREEMENTS

The Company and Mississippi Power jointly own Plant Daniel Units 1 and 2, which together represent capacity of 1,000 MWs. Plant Daniel is a generating plant located in Jackson County, Mississippi. In accordance with the operating agreement, Mississippi Power acts as the Company's agent with respect to the construction, operation, and maintenance of these units.

The Company and Georgia Power jointly own the 818 MWs capacity Plant Scherer Unit 3. Plant Scherer is a generating plant located near Forsyth, Georgia. In accordance with the operating agreement, Georgia Power acts as the Company's agent with respect to the construction, operation, and maintenance of the unit.

The Company's proportionate share of expenses related to both plants is included in the corresponding operating expense accounts in the statements of income and the Company is responsible for providing its own financing.

At December 31, 2012, the Company's percentage ownership and investment in these jointly owned facilities were as follows:

	Plant Scherer Unit 3 (coal)	Plant Daniel Units 1 & 2 (coal)
	(in thousands)	
Plant in service	$ 373,576 [(a)]	$ 277,440
Accumulated depreciation	117,181	165,120
Construction work in progress	8,763	69,774
Ownership	25%	50%

(a) Includes net plant acquisition adjustment of $2.3 million.

The Company's proportionate share of its plant operating expenses is included in the corresponding operating expenses in the statements of income and the Company is responsible for providing its own financing.

5. INCOME TAXES

On behalf of the Company, Southern Company files a consolidated federal income tax return and combined state income tax returns for the States of Alabama, Georgia, and Mississippi. In addition, the Company files a separate company income tax return for the State of Florida. Under a joint consolidated income tax allocation agreement, each subsidiary's current and deferred tax expense is computed on a stand-alone basis and no subsidiary is allocated more current expense than would be paid if it filed a separate income tax return. In accordance with Internal Revenue Service (IRS) regulations, each company is jointly and severally liable for the federal tax liability.

Current and Deferred Income Taxes

Details of income tax provisions are as follows:

	2012	2011	2010
		(in thousands)	
Federal -			
Current	$ **(92,610)**	$ (1,548)	$ (14,115)
Deferred	**161,096**	56,087	77,452
	68,486	54,539	63,337
State -			
Current	**(2,484)**	(412)	2,948
Deferred	**13,209**	7,141	5,229
	10,725	6,729	8,177
Total	$ **79,211**	$ 61,268	$ 71,514

The tax effects of temporary differences between the carrying amounts of assets and liabilities in the financial statements and their respective tax bases, which give rise to deferred tax assets and liabilities, are as follows:

	2012	2011
	(in thousands)	
Deferred tax liabilities-		
Accelerated depreciation	$ **696,502**	$ 496,392
Pension and other employee benefits	**28,579**	25,268
Regulatory assets associated with employee benefit obligations	**57,279**	44,871
Regulatory assets associated with asset retirement obligations	**6,502**	4,345
Other	**16,019**	14,804
Total	**804,881**	585,680
Deferred tax assets-		
Federal effect of state deferred taxes	**20,656**	16,684
Postretirement benefits	**17,905**	16,769
Fuel recovery clause	**6,922**	2,531
Pension and other employee benefits	**61,939**	49,116
Property reserve	**13,773**	13,159
Other comprehensive loss	**993**	1,353
Asset retirement obligations	**6,502**	4,345
Alternative minimum tax carryforward	**938**	7,151
Other	**28,273**	20,191
Total	**157,901**	131,299
Net deferred tax liabilities	**646,980**	454,381
Portion included in current assets (liabilities), net	**1,972**	4,597
Accumulated deferred income taxes	$ **648,952**	$ 458,978

At December 31, 2012, the tax-related regulatory assets to be recovered from customers were $50.5 million. These assets are primarily attributable to tax benefits that flowed through to customers in prior years, to deferred taxes previously recognized at rates lower than the current enacted tax law, and to taxes applicable to capitalized AFUDC.

At December 31, 2012, the tax-related regulatory liabilities to be credited to customers were $6.5 million. These liabilities are primarily attributable to deferred taxes previously recognized at rates higher than the current enacted tax law and to unamortized investment tax credits.

In accordance with regulatory requirements, deferred investment tax credits are amortized over the life of the related property with such amortization normally applied as a credit to reduce depreciation in the statements of income. Credits amortized in this manner amounted to $1.4 million in 2012, $1.3 million in 2011, and $1.5 million in 2010. At December 31, 2012, all investment tax credits available to reduce federal income taxes payable had been utilized.

In 2010, the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010 (Tax Relief Act) was signed into law. Major tax incentives in the Tax Relief Act include 100% bonus depreciation for property placed in service after September 8, 2010 and through 2011 (and for certain long-term production-period projects placed in service in 2012) and 50% bonus depreciation for property placed in service in 2012 (and for certain long-term production-period projects to be placed in service in 2013). The application of the bonus depreciation provisions in the Tax Relief Act significantly increased deferred tax liabilities related to accelerated depreciation.

Effective Tax Rate

A reconciliation of the federal statutory income tax rate to the effective income tax rate is as follows:

	2012	2011	2010
Federal statutory rate	**35.0%**	35.0%	35.0%
State income tax, net of federal deduction	**3.3**	2.5	2.7
Non-deductible book depreciation	**0.5**	0.5	0.3
Differences in prior years' deferred and current tax rates	**(0.2)**	(0.3)	(0.3)
AFUDC equity	**(0.9)**	(2.0)	(1.3)
Other, net	**(0.2)**	(0.2)	(0.5)
Effective income tax rate	**37.5%**	35.5%	35.9%

The increase in the 2012 effective tax rate is primarily the result of a decrease in AFUDC equity, which is not taxable, and a decrease in state tax credits.

Unrecognized Tax Benefits

For 2012, the total amount of unrecognized tax benefits increased by $2.1 million, resulting in a balance of $5.0 million as of December 31, 2012.

Changes during the year in unrecognized tax benefits were as follows:

	2012	2011	2010
		(in thousands)	
Unrecognized tax benefits at beginning of year	**$ 2,892**	$ 3,870	$ 1,639
Tax positions from current periods	**2,630**	540	1,027
Tax positions from prior periods	**515**	(1,518)	1,204
Reductions due to settlements	**(1,030)**	—	—
Balance at end of year	**$ 5,007**	$ 2,892	$ 3,870

The tax positions increase from current periods for 2012 relates primarily to the tax accounting method change for repairs-generation assets. The tax positions increase from prior periods for 2012 also relates primarily to the tax accounting method change for repairs-generation assets. See "Tax Method of Accounting for Repairs" herein for additional information. The American Jobs Creation Act of 2004 created a tax deduction for a portion of income attributable to U.S. production activities as defined in Section 199 of the Internal Revenue Code (production activities deduction). The reductions due to settlements for 2012 relate to a settlement with the IRS of the calculation methodology for the production activities deduction.

The impact on the Company's effective tax rate, if recognized, was as follows:

	2012	2011	2010
		(in thousands)	
Tax positions impacting the effective tax rate	**$ 45**	$ 1,804	$ 1,826
Tax positions not impacting the effective tax rate	**4,962**	1,088	2,044
Balance of unrecognized tax benefits	**$ 5,007**	$ 2,892	$ 3,870

The tax positions impacting the effective tax rate for 2012 relate primarily to the research and development credit. The tax positions not impacting the effective tax rate for 2012 relate to the timing difference associated with the tax accounting method change for repairs-generation assets. See "Tax Method of Accounting for Repairs" herein for additional information. These amounts are presented on a gross basis without considering the related federal or state income tax impact.

Accrued interest for unrecognized tax benefits was as follows:

	2012	2011	2010
		(in thousands)	
Interest accrued at beginning of year	$ 283	$ 210	$ 90
Interest reclassified due to settlements	(283)	—	—
Interest accrued during the year	—	73	120
Balance at end of year	$ —	$ 283	$ 210

The Company classifies interest on tax uncertainties as interest expense. The Company did not accrue any penalties on uncertain tax positions.

It is reasonably possible that the amount of the unrecognized tax benefits associated with a majority of the Company's unrecognized tax positions will significantly increase or decrease within 12 months. The resolution of the tax accounting method change for repairs-generation assets, as well as the conclusion or settlement of state audits, could impact the balances significantly. At this time, an estimate of the range of reasonably possible outcomes cannot be determined.

The IRS has audited and closed all of Southern Company's consolidated federal income tax returns prior to 2009 and has settled its audits of Southern Company's consolidated federal income tax returns for 2009 and 2010, in principle, pending final approval. Additionally, the IRS has audited and closed Southern Company's 2011 consolidated federal income tax return. For tax years 2010 through 2013, Southern Company is a participant in the Compliance Assurance Process of the IRS. The audits for the Company's state income tax returns have either been concluded, or the statute of limitations has expired, for years prior to 2007.

Tax Method of Accounting for Repairs

Southern Company submitted a tax accounting method change related to the deductibility of repair costs associated with its subsidiaries' generation, transmission, and distribution systems effective for the 2009 consolidated federal income tax return in 2010. In August 2011, the IRS issued a revenue procedure, which provides a safe harbor method of accounting that taxpayers may use to determine eligible repair costs for transmission and distribution property. The IRS continues to work with the utility industry in an effort to define eligible repair costs for generation assets in a consistent manner for all utilities. The IRS published regulations on the deduction and capitalization of expenditures related to tangible property that generally apply for tax years beginning on or after January 1, 2014. The utility industry anticipates more detailed guidance concerning these regulations. Due to the uncertainty regarding the ultimate resolution of the repair costs for generation assets, an unrecognized tax position has been recorded for the tax accounting method change for repairs-generation assets. The ultimate outcome of this matter cannot be determined at this time; however, it is not expected to materially impact net income.

6. FINANCING

Securities Due Within One Year

Approximately $60 million will be required through December 31, 2013 to fund maturities of long-term debt.

Maturities from 2014 through 2017 applicable to total long-term debt are as follows: $75 million in 2014; $110 million in 2016; and $85 million in 2017. There are no scheduled maturities in 2015.

Senior Notes

At December 31, 2012 and 2011, the Company had a total of $945 million and $936.4 million of senior notes outstanding, respectively. These senior notes are effectively subordinate to all secured debt of the Company, which totals approximately $41 million at December 31, 2012.

In May 2012, the Company issued $100 million aggregate principal amount of Series 2012A 3.10% Senior Notes due May 15, 2022. The net proceeds from the sale of the Series 2012A Senior Notes were used to redeem all of approximately $61 million aggregate principal amount of the Company's Series F 5.60% Senior Insured Quarterly Notes due April 1, 2033 and $30 million aggregate principal amount of the Company's Series H 5.25% Senior Notes due July 15, 2033, to repay a portion of the Company's outstanding short-term indebtedness, and for general corporate purposes, including the Company's continuous construction program.

Pollution Control Revenue Bonds

Pollution control obligations represent loans to the Company from public authorities of funds derived from sales by such authorities of revenue bonds issued to finance pollution control and solid waste disposal facilities. The Company is required to make payments sufficient for the authorities to meet principal and interest requirements of such bonds. The amount of tax-exempt pollution control revenue bonds outstanding at December 31, 2012 and 2011 was $309 million.

In November 2012, the Mississippi Business Finance Corporation issued $13 million aggregate principal amount of Mississippi Business Finance Corporation Solid Waste Disposal Facilities Revenue Refunding Bonds, Series 2012 (Gulf Power Company Project), due November 1, 2042 for the benefit of the Company. The proceeds were used in December 2012 to redeem the Mississippi Business Finance Corporation Solid Waste Disposal Facilities Revenue Refunding Bonds, Series 2002 (Gulf Power Company Project), due September 1, 2028.

Outstanding Classes of Capital Stock

The Company currently has preferred stock, Class A preferred stock, preference stock, and common stock authorized. The Company's preferred stock and Class A preferred stock, without preference between classes, rank senior to the Company's preference stock and common stock with respect to payment of dividends and voluntary or involuntary dissolution. No shares of preferred stock or Class A preferred stock were outstanding at December 31, 2012. The Company's preference stock ranks senior to the common stock with respect to the payment of dividends and voluntary or involuntary dissolution. Certain series of the preference stock are subject to redemption at the option of the Company on or after a specified date (typically five or 10 years after the date of issuance) at a redemption price equal to 100% of the liquidation amount of the preference stock. In addition, one series of the preference stock may be redeemed earlier at a redemption price equal to 100% of the liquidation amount plus a make-whole premium based on the present value of the liquidation amount and future dividends.

In January 2012, the Company issued to Southern Company 400,000 shares of the Company's common stock, without par value, and realized proceeds of $40 million. Subsequent to December 31, 2012, the Company issued to Southern Company 400,000 shares of the Company's common stock, without par value, and realized proceeds of $40 million. The proceeds were used to repay a portion of the Company's short-term debt and for other general corporate purposes, including the Company's continuous construction program.

Dividend Restrictions

The Company can only pay dividends to Southern Company out of retained earnings or paid-in-capital.

Assets Subject to Lien

The Company has granted a lien on its property at Plant Daniel in connection with the issuance of two series of pollution control revenue bonds with an outstanding principal amount of $41 million. There are no agreements or other arrangements among the Southern Company system companies under which the assets of one company have been pledged or otherwise made available to satisfy obligations of Southern Company or any of its subsidiaries.

Bank Credit Arrangements

At December 31, 2012, committed credit arrangements with banks were as follows:

Expires[a]				Executable Term-Loans		Due Within One Year	
2013	2014	Total	Unused	One Year	Two Years	Term Out	No Term Out
$ 80	$ 195	$ 275	$ 275	$ 45	$ —	$ 45	$ 35

(a) No credit arrangements expire after 2014.

During 2012, the Company renewed a $30 million credit arrangement and changed the terms of the credit arrangement so that it expires after two years instead of one year, which is reflected in the table above. The Company expects to renew its credit arrangements, as needed, prior to expiration. Of the $275 million of unused credit arrangements, $69 million provides support for variable rate pollution control revenue bonds and $206 million was available for liquidity support for the Company's commercial paper program and for other general corporate purposes. Most of the credit arrangements require payment of commitment fees based on the unused portion of the commitments. Commitment fees average less than 1/4 of 1% for the Company.

Most of those credit arrangements with banks contain covenants that limit the Company's debt level to 65% of total capitalization, as defined in the arrangements. At December 31, 2012, the Company was in compliance with these covenants.

In addition, the credit arrangements typically contain cross default provisions that are restricted only to indebtedness of the Company. The Company is currently in compliance with all such covenants.

For short-term cash needs, the Company borrows primarily through a commercial paper program that has the liquidity support of the Company's committed bank credit arrangements. The Company may also borrow through various other arrangements with banks. Commercial paper and short-term bank loans are included in notes payable in the balance sheets.

Details of short-term borrowings included in notes payable on the balance sheets were as follows:

	Short-term Debt at the End of the Period [a]	
	Amount Outstanding	Weighted Average Interest Rate
	(in millions)	
December 31, 2012:		
Commercial paper	$ 124	0.3%
December 31, 2011:		
Commercial paper	$ 111	0.2%

(a) Excludes notes payable related to other energy service contracts of $3.2 million and $3.6 million for the periods ended December 31, 2012 and 2011, respectively.

7. COMMITMENTS

Fuel and Purchased Power Agreements

To supply a portion of the fuel requirements of its generating plants, the Company has entered into various long-term commitments for the procurement of fossil fuel which are not recognized on the balance sheets. In 2012, 2011, and 2010, the Company incurred fuel expense of $544.9 million, $662.3 million, and $742.3 million, the majority of which was purchased under long-term commitments. The Company expects that a substantial amount of its future fuel needs will continue to be purchased under long-term commitments.

In addition, the Company has entered into various long-term commitments for the purchase of capacity, energy, and transmission, some of which are accounted for as operating leases. The energy-related costs associated with PPAs are recovered through the fuel cost recovery clause. The capacity and transmission-related costs associated with PPAs are recovered through the purchased power capacity cost recovery clause. Capacity expense under purchased power agreements accounted for as operating leases was $24.6 million, $25.1 million, and $25.1 million for 2012, 2011, and 2010, respectively.

Estimated total minimum long-term commitments at December 31, 2012 were as follows:

	Operating Lease PPAs
	(in millions)
2013	$ 24.7
2014	52.9
2015	78.6
2016	78.7
2017	78.8
2018 and thereafter	428.1
Total	**$ 741.8**

SCS may enter into various types of wholesale energy and natural gas contracts acting as an agent for the Company and all of the other Southern Company traditional operating companies and Southern Power. Under these agreements, each of the traditional operating companies and Southern Power may be jointly and severally liable. The credit rating of Southern Power is currently below that of the traditional operating companies. Accordingly, Southern Company has entered into keep-well agreements with the Company and each of the other traditional operating companies to ensure the Company will not subsidize or be responsible for any costs, losses, liabilities, or damages resulting from the inclusion of Southern Power as a contracting party under these agreements.

Operating Leases

The Company has operating lease agreements with various terms and expiration dates. Total rent expense was $20.1 million, $21.9 million, and $23.1 million for 2012, 2011, and 2010, respectively.

Estimated total minimum lease payments under operating leases at December 31, 2012 were as follows:

	Minimum Lease Payments		
	Barges & Railcars	Other	Total
		(in millions)	
2013	$ 18.6	$ 0.3	$ 18.9
2014	17.2	0.3	17.5
2015	1.1	0.1	1.2
2016	0.9	0.1	1.0
2017	1.0	0.1	1.1
2018 and thereafter	—	—	—
Total	**$ 38.8**	**$ 0.9**	**$ 39.7**

The Company and Mississippi Power jointly entered into operating lease agreements for aluminum railcars for the transportation of coal to Plant Daniel. The Company has the option to purchase the railcars at the greater of lease termination value or fair market value or to renew the leases at the end of each lease term. The Company and Mississippi Power also have separate lease agreements for other railcars that do not include purchase options. The Company's share of the lease costs, charged to fuel inventory and recovered through the fuel cost recovery clause, was $3.6 million in 2012, $2.6 million in 2011, and $3.5 million in 2010. The Company's annual railcar lease payments for 2013 through 2017 will average approximately $1.6 million. The Company has no lease payment obligations for the period 2018 and thereafter.

8. STOCK COMPENSATION

Stock Options

Southern Company provides non-qualified stock options through its Omnibus Incentive Compensation Plan to a large segment of the Company's employees ranging from line management to executives. As of December 31, 2012, there were 218 current and former employees of the Company participating in the stock option program, and there were 39 million shares of Southern Company common stock remaining available for awards under the Omnibus Incentive Compensation Plan. The prices of options were at the fair market value of the shares on the dates of grant. These options become exercisable pro rata over a maximum period of three years from the date of grant. The Company generally recognizes stock option expense on a straight-line basis over the vesting period which equates to the requisite service period; however, for employees who are eligible for retirement, the total cost is expensed at the grant date. Options outstanding will expire no later than 10 years after the date of grant, unless terminated earlier by the Southern Company Board of Directors in accordance with the Omnibus Incentive Compensation Plan. For certain stock option awards, a change in control will provide accelerated vesting.

The estimated fair values of stock options granted were derived using the Black-Scholes stock option pricing model. Expected volatility was based on historical volatility of Southern Company's stock over a period equal to the expected term.

Southern Company used historical exercise data to estimate the expected term that represents the period of time that options granted to employees are expected to be outstanding. The risk-free rate was based on the U.S. Treasury yield curve in effect at the time of grant that covers the expected term of the stock options.

The following table shows the assumptions used in the pricing model and the weighted average grant-date fair value of stock options granted:

Year Ended December 31	2012	2011	2010
Expected volatility	**17.7%**	17.5%	17.4%
Expected term *(in years)*	**5.0**	5.0	5.0
Interest rate	**0.9%**	2.3%	2.4%
Dividend yield	**4.2%**	4.8%	5.6%
Weighted average grant-date fair value	**$3.39**	$3.23	$2.23

The Company's activity in the stock option program for 2012 is summarized below:

	Shares Subject to Option	Weighted Average Exercise Price
Outstanding at December 31, 2011	1,498,663	$ 33.75
Granted	244,607	44.43
Exercised	(353,749)	31.97
Cancelled	(606)	42.08
Outstanding at December 31, 2012	**1,388,915**	**$ 36.08**
Exercisable at December 31, 2012	**884,888**	**$ 34.02**

The number of stock options vested, and expected to vest in the future, as of December 31, 2012, was not significantly different from the number of stock options outstanding at December 31, 2012 as stated above. As of December 31, 2012, the weighted average remaining contractual term for the options outstanding and options exercisable was approximately six years and five years, respectively, and the aggregate intrinsic value for the options outstanding and options exercisable was $9.7 million and $7.8 million, respectively.

As of December 31, 2012, there was $0.3 million of total unrecognized compensation cost related to stock option awards not yet vested. That cost is expected to be recognized over a weighted average period of approximately 11 months.

For the years ended December 31, 2012, 2011, and 2010, total compensation cost for stock option awards recognized in income was $0.7 million, $0.7 million, and $0.8 million, respectively, with the related tax benefit also recognized in income of $0.3 million, $0.3 million, and $0.3 million, respectively.

The compensation cost and tax benefits related to the grant and exercise of Southern Company stock options to the Company's employees are recognized in the Company's financial statements with a corresponding credit to equity, representing a capital contribution from Southern Company.

The total intrinsic value of options exercised during the years ended December 31, 2012, 2011, and 2010 was $3.8 million, $3.2 million, and $1.6 million, respectively. The actual tax benefit realized by the Company for the tax deductions from stock option exercises totaled $1.5 million, $1.2 million, and $0.6 million for the years ended December 31, 2012, 2011, and 2010, respectively.

Performance Shares

Southern Company provides performance share award units through its Omnibus Incentive Compensation Plan to a large segment of the Company's employees ranging from line management to executives. The performance share units granted under the plan vest at the end of a three-year performance period which equates to the requisite service period. Employees that retire prior to the end of the three-year period receive a pro rata number of shares, issued at the end of the performance period, based on actual months of service prior to retirement. The value of the award units is based on Southern Company's total shareholder return (TSR) over the three-year performance period which measures Southern Company's relative performance against a group of industry peers. The performance shares are delivered in common stock following the end of the performance period based on Southern Company's actual TSR and may range from 0% to 200% of the original target performance share amount.

The fair value of performance share awards is determined as of the grant date using a Monte Carlo simulation model to estimate the TSR of Southern Company's stock among the industry peers over the performance period. The Company recognizes compensation expense on a straight-line basis over the three-year performance period without remeasurement. Compensation expense for awards where the service condition is met is recognized regardless of the actual number of shares issued. The expected volatility was based on the historical volatility of Southern Company's stock over a period equal to the performance period. The risk-free rate was based on the U.S. Treasury yield curve in effect at the time of grant that covers the performance period of the award units.

The following table shows the assumptions used in the pricing model and the weighted average grant-date fair value of performance share award units granted:

Year Ended December 31	2012	2011	2010
Expected volatility	**16.0%**	19.2%	20.7%
Expected term *(in years)*	**3.0**	3.0	3.0
Interest rate	**0.4%**	1.4%	1.4%
Annualized dividend rate	**$1.89**	$1.82	$1.75
Weighted average grant-date fair value	**$41.99**	$35.97	$30.13

Total unvested performance share units outstanding as of December 31, 2011 were 66,662. During 2012, 29,444 performance share units were granted, 26,738 performance share units were vested, and 563 performance share units were forfeited resulting in 68,805 unvested units outstanding at December 31, 2012. In January 2013, the vested performance share award units were converted into 36,105 shares outstanding at a share price of $43.05 for the three-year performance and vesting period ended December 31, 2012.

For the years ended December 31, 2012, 2011, and 2010, total compensation cost for performance share units recognized in income was $1.0 million, $0.7 million, and $0.3 million, respectively, with the related tax benefit also recognized in income of $0.4 million, $0.3 million, and $0.1 million, respectively. As of December 31, 2012, there was $1.0 million of total unrecognized compensation cost related to performance share award units that will be recognized over a weighted average period of approximately 11 months.

9. FAIR VALUE MEASUREMENTS

Fair value measurements are based on inputs of observable and unobservable market data that a market participant would use in pricing the asset or liability. The use of observable inputs is maximized where available and the use of unobservable inputs is minimized for fair value measurement and reflects a three-tier fair value hierarchy that prioritizes inputs to valuation techniques used for fair value measurement.

- Level 1 consists of observable market data in an active market for identical assets or liabilities.
- Level 2 consists of observable market data, other than that included in Level 1, that is either directly or indirectly observable.
- Level 3 consists of unobservable market data. The input may reflect the assumptions of the Company of what a market participant would use in pricing an asset or liability. If there is little available market data, then the Company's own assumptions are the best available information.

In the case of multiple inputs being used in a fair value measurement, the lowest level input that is significant to the fair value measurement represents the level in the fair value hierarchy in which the fair value measurement is reported.

As of December 31, 2012, assets and liabilities measured at fair value on a recurring basis during the period, together with the level of the fair value hierarchy in which they fall, were as follows:

	Fair Value Measurements Using			
As of December 31, 2012:	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Total**
		(in thousands)		
Assets:				
Energy-related derivatives	$ —	$ 4,358	$ —	$ 4,358
Cash equivalents	15,231	—	—	15,231
Total	$ 15,231	$ 4,358	$ —	$ 19,589
Liabilities:				
Energy-related derivatives	$ —	$ 27,112	$ —	$ 27,112

As of December 31, 2011, assets and liabilities measured at fair value on a recurring basis during the period, together with the level of the fair value hierarchy in which they fall, were as follows:

	Fair Value Measurements Using			
As of December 31, 2011:	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Total**
		(in thousands)		
Assets:				
Energy-related derivatives	$ —	$ 198	$ —	$ 198
Cash equivalents	13,949	—	—	13,949
Total	$ 13,949	$ 198	$ —	$ 14,147
Liabilities:				
Energy-related derivatives	$ —	$ 40,983	$ —	$ 40,983

Valuation Methodologies

The energy-related derivatives primarily consist of over-the-counter financial products for natural gas and physical power products including, from time to time, basis swaps. These are standard products used within the energy industry and are valued using the market approach. The inputs used are mainly from observable market sources, such as forward natural gas prices, power prices, implied volatility, and London Interbank Offered Rate interest rates. See Note 10 for additional information on how these derivatives are used.

As of December 31, 2012 and 2011, the fair value measurements of investments calculated at net asset value per share (or its equivalent), as well as the nature and risks of those investments, were as follows:

	Fair Value	Unfunded Commitments	Redemption Frequency	Redemption Notice Period
As of December 31, 2012:	*(in thousands)*			
Cash equivalents:				
Money market funds	$15,231	None	Daily	Not applicable
As of December 31, 2011:				
Cash equivalents:				
Money market funds	$13,949	None	Daily	Not applicable

The money market funds are short-term investments of excess funds in various money market mutual funds, which are portfolios of short-term debt securities. The money market funds are regulated by the SEC and typically receive the highest rating from credit rating agencies. Regulatory and rating agency requirements for money market funds include minimum credit ratings and maximum maturities for individual securities and a maximum weighted average portfolio maturity. Redemptions are available on a same day basis up to the full amount of the Company's investment in the money market funds.

As of December 31, 2012 and 2011, other financial instruments for which the carrying amount did not equal fair value were as follows:

	Carrying Amount	Fair Value
	(in thousands)	
Long-term debt:		
2012	**$ 1,245,870**	**$ 1,367,404**
2011	$ 1,235,447	$ 1,350,237

The fair values are determined using Level 2 measurements and are based on quoted market prices for the same or similar issues or on the current rates offered to the Company.

10. DERIVATIVES

The Company is exposed to market risks, primarily commodity price risk and interest rate risk. To manage the volatility attributable to these exposures, the Company nets its exposures, where possible, to take advantage of natural offsets and may enter into various derivative transactions for the remaining exposures pursuant to the Company's policies in areas such as counterparty exposure and risk management practices. The Company's policy is that derivatives are to be used primarily for hedging purposes and mandates strict adherence to all applicable risk management policies. Derivative positions are monitored using techniques including, but not limited to, market valuation, value at risk, stress testing, and sensitivity analysis. Derivative instruments are recognized at fair value in the balance sheets as either assets or liabilities and are presented on a gross basis.

Energy-Related Derivatives

The Company enters into energy-related derivatives to hedge exposures to electricity, gas, and other fuel price changes. However, due to cost-based rate regulations and other various cost recovery mechanisms, the Company has limited exposure to market volatility in commodity fuel prices and prices of electricity. The Company manages fuel hedging programs, implemented per the guidelines of the Florida PSC, through the use of financial derivative contracts, which is expected to continue to mitigate price volatility.

To mitigate residual risks relative to movements in electricity prices, the Company may enter into physical fixed-price contracts for the purchase and sale of electricity through the wholesale electricity market. To mitigate residual risks relative to movements in gas prices, the Company may enter into fixed-price contracts for natural gas purchases; however, a significant portion of contracts are priced at market.

Energy-related derivative contracts are accounted for in one of two methods:

- *Regulatory Hedges* — Energy-related derivative contracts which are designated as regulatory hedges relate primarily to the Company's fuel hedging programs, where gains and losses are initially recorded as regulatory liabilities and assets, respectively, and then are included in fuel expense as the underlying fuel is used in operations and ultimately recovered through the fuel cost recovery clause.
- *Not Designated* — Gains and losses on energy-related derivative contracts that are not designated or fail to qualify as hedges are recognized in the statements of income as incurred.

Some energy-related derivative contracts require physical delivery as opposed to financial settlement, and this type of derivative is both common and prevalent within the electric industry. When an energy-related derivative contract is settled physically, any cumulative unrealized gain or loss is reversed and the contract price is recognized in the respective line item representing the actual price of the underlying goods being delivered.

At December 31, 2012, the net volume of energy-related derivative contracts for natural gas positions for the Company, together with the longest hedge date over which it is hedging its exposure to the variability in future cash flows for forecasted transactions and the longest date for derivatives not designated as hedges, were as follows:

Gas		
Net Purchased mmBtu*	**Longest Hedge Date**	**Longest Non-Hedge Date**
(in thousands)		
70,510	2017	—

* mmBtu — million British thermal units

Interest Rate Derivatives

The Company may also enter into interest rate derivatives to hedge exposure to changes in interest rates. Derivatives related to existing variable rate securities or forecasted transactions are accounted for as cash flow hedges where the effective portion of the derivatives' fair value gains or losses is recorded in OCI and is reclassified into earnings at the same time the hedged transactions affect earnings. The derivatives employed as hedging instruments are structured to minimize ineffectiveness, which is recorded directly to earnings.

At December 31, 2012, there were no interest rate derivatives outstanding.

The estimated pre-tax losses that will be reclassified from OCI to interest expense for the 12-month period ending December 31, 2013 are $0.8 million. The Company has deferred gains and losses that are expected to be amortized into earnings through 2020.

Derivative Financial Statement Presentation and Amounts

At December 31, 2012 and 2011, the fair value of energy-related derivatives was reflected in the balance sheets as follows:

	Asset Derivatives			Liability Derivatives		
Derivative Category	**Balance Sheet Location**	**2012**	2011	**Balance Sheet Location**	**2012**	2011
		(in thousands)			*(in thousands)*	
Derivatives designated as hedging instruments for regulatory purposes						
Energy-related derivatives:						
	Other current assets	**$ 1,293**	$ 154	Liabilities from risk management activities	**$ 16,529**	$ 22,786
	Other deferred charges and assets	**3,065**	44	Other deferred credits and liabilities	**10,583**	18,197
Total derivatives designated as hedging instruments for regulatory purposes		**$ 4,358**	$ 198		**$ 27,112**	$ 40,983
Derivatives not designated as hedging instruments						
Energy-related derivatives:						
	Other current assets	**$ —**	$ —	Liabilities from risk management activities	**$ —**	$ —
Total		**$ 4,358**	$ 198		**$ 27,112**	$ 40,983

All derivative instruments are measured at fair value. See Note 9 for additional information.

At December 31, 2012 and 2011, the pre-tax effects of unrealized derivative gains (losses) arising from energy-related derivative instruments designated as regulatory hedging instruments and deferred on the balance sheets were as follows:

	Unrealized Losses			Unrealized Gains		
Derivative Category	**Balance Sheet Location**	**2012**	2011	**Balance Sheet Location**	**2012**	2011
		(in thousands)			*(in thousands)*	
Energy-related derivatives:						
	Other regulatory assets, current	**$ (16,529)**	$ (22,786)	Other regulatory liabilities, current	**$ 1,293**	$ 154
	Other regulatory assets, deferred	**(10,583)**	(18,197)	Other regulatory liabilities, deferred	**3,065**	44
Total energy-related derivative gains (losses)		**$ (27,112)**	$ (40,983)		**$ 4,358**	$ 198

For the years ended December 31, 2012, 2011, and 2010, the pre-tax effects of interest rate derivatives designated as cash flow hedging instruments on the statements of income were as follows:

Derivatives in Cash Flow Hedging Relationships	Gain (Loss) Recognized in OCI on Derivative (Effective Portion)			Gain (Loss) Reclassified from Accumulated OCI into Income (Effective Portion)			
					Amount		
Derivative Category	2012	2011	2010	Statements of Income Location	2012	2011	2010
		(in thousands)				*(in thousands)*	
Interest rate derivatives	$ —	$ —	$ (1,405)	Interest expense, net of amounts capitalized	$ (933)	$ (933)	$ (974)

There was no material ineffectiveness recorded in earnings for any period presented.

For the years ended December 31, 2012, 2011, and 2010, the pre-tax effects of energy-related derivatives not designated as hedging instruments on the statements of income were not material.

Contingent Features

The Company does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. There are certain derivatives that could require collateral, but not accelerated payment, in the event of various credit rating changes of certain affiliated companies. At December 31, 2012, the fair value of derivative liabilities with contingent features was $4 million.

At December 31, 2012, the Company had no collateral posted with its derivative counterparties; however, because of the joint and several liability features underlying these derivatives, the maximum potential collateral requirements arising from the credit-risk-related contingent features, at a rating below BBB- and/or Baa3, were $15 million.

Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. The Company participates in certain agreements that could require collateral in the event that one or more Southern Company system power pool participants has a credit rating change to below investment grade.

11. QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

Summarized quarterly financial information for 2012 and 2011 is as follows:

Quarter Ended	Operating Revenues	Operating Income	Net Income After Dividends on Preference Stock
		(in thousands)	
March 2012	**$ 316,245**	**$ 49,098**	**$ 20,666**
June 2012	**370,208**	**71,465**	**34,963**
September 2012	**421,819**	**93,813**	**47,754**
December 2012	**331,490**	**53,818**	**22,549**
March 2011	$ 324,608	$ 32,044	$ 11,691
June 2011	399,265	67,387	33,352
September 2011	468,030	81,454	41,217
December 2011	327,909	43,839	18,745

The Company's business is influenced by seasonal weather conditions.

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	2012	2011	2010	2009	2008
Operating Revenues (in thousands)	**$ 1,439,762**	$ 1,519,812	$ 1,590,209	$ 1,302,229	$ 1,387,203
Net Income After Dividends on Preference Stock (in thousands)	**$ 125,932**	$ 105,005	$ 121,511	$ 111,233	$ 98,345
Cash Dividends on Common Stock (in thousands)	**$ 115,800**	$ 110,000	$ 104,300	$ 89,300	$ 81,700
Return on Average Common Equity (percent)	**10.92**	9.55	11.69	12.18	12.66
Total Assets (in thousands)	**$ 4,177,402**	$ 3,871,881	$ 3,584,939	$ 3,293,607	$ 2,879,025
Gross Property Additions (in thousands)	**$ 325,237**	$ 337,830	$ 285,379	$ 450,421	$ 390,744
Capitalization (in thousands):					
Common stock equity	**$ 1,180,742**	$ 1,124,948	$ 1,075,036	$ 1,004,292	$ 822,092
Preference stock	**97,998**	97,998	97,998	97,998	97,998
Long-term debt	**1,185,870**	1,235,447	1,114,398	978,914	849,265
Total (excluding amounts due within one year)	**$ 2,464,610**	$ 2,458,393	$ 2,287,432	$ 2,081,204	$ 1,769,355
Capitalization Ratios (percent):					
Common stock equity	**47.9**	45.8	47.0	48.3	46.5
Preference stock	**4.0**	4.0	4.3	4.7	5.5
Long-term debt	**48.1**	50.2	48.7	47.0	48.0
Total (excluding amounts due within one year)	**100.0**	100.0	100.0	100.0	100.0
Customers (year-end):					
Residential	**379,922**	378,248	376,561	374,091	373,595
Commercial	**53,808**	53,450	53,263	53,272	53,548
Industrial	**264**	273	272	279	287
Other	**577**	565	562	512	499
Total	**434,571**	432,536	430,658	428,154	427,929
Employees (year-end)	**1,416**	1,424	1,330	1,365	1,342

	2012	2011	2010	2009	2008
Operating Revenues (in thousands):					
Residential	$ **609,454**	$ 637,352	$ 707,196	$ 588,073	$ 581,723
Commercial	**389,936**	408,389	439,468	376,125	369,625
Industrial	**140,490**	158,367	157,591	138,164	165,564
Other	**4,591**	4,382	4,471	4,206	3,854
Total retail	**1,144,471**	1,208,490	1,308,726	1,106,568	1,120,766
Wholesale — non-affiliates	**106,881**	133,555	109,172	94,105	97,065
Wholesale — affiliates	**123,636**	111,346	110,051	32,095	106,989
Total revenues from sales of electricity	**1,374,988**	1,453,391	1,527,949	1,232,768	1,324,820
Other revenues	**64,774**	66,421	62,260	69,461	62,383
Total	$ **1,439,762**	$ 1,519,812	$ 1,590,209	$ 1,302,229	$ 1,387,203
Kilowatt-Hour Sales (in thousands):					
Residential	**5,053,724**	5,304,769	5,651,274	5,254,491	5,348,642
Commercial	**3,858,521**	3,911,399	3,996,502	3,896,105	3,960,923
Industrial	**1,725,121**	1,798,688	1,685,817	1,727,106	2,210,597
Other	**25,267**	25,430	25,602	25,121	23,237
Total retail	**10,662,633**	11,040,286	11,359,195	10,902,823	11,543,399
Wholesale — non-affiliates	**977,395**	2,012,986	1,675,079	1,813,592	1,816,839
Wholesale — affiliates	**4,369,964**	2,607,873	2,436,883	870,470	1,871,158
Total	**16,009,992**	15,661,145	15,471,157	13,586,885	15,231,396
Average Revenue Per Kilowatt-Hour (cents):					
Residential	**12.06**	12.01	12.51	11.19	10.88
Commercial	**10.11**	10.44	11.00	9.65	9.33
Industrial	**8.14**	8.80	9.35	8.00	7.49
Total retail	**10.73**	10.95	11.52	10.15	9.71
Wholesale	**4.31**	5.30	5.33	4.70	5.53
Total sales	**8.59**	9.28	9.88	9.07	8.70
Residential Average Annual Kilowatt-Hour Use Per Customer	**13,303**	14,028	15,036	14,049	14,274
Residential Average Annual Revenue Per Customer	$ **1,604**	$ 1,685	$ 1,882	$ 1,572	$ 1,552
Plant Nameplate Capacity Ratings (year-end) (megawatts)	**2,663**	2,663	2,663	2,659	2,659
Maximum Peak-Hour Demand (megawatts):					
Winter	**2,130**	2,485	2,544	2,310	2,360
Summer	**2,344**	2,527	2,519	2,538	2,533
Annual Load Factor (percent)	**56.3**	54.5	56.1	53.8	56.7
Plant Availability Fossil-Steam (percent)*	**82.5**	84.7	94.7	89.7	88.6
Source of Energy Supply (percent):					
Coal	**34.6**	49.4	64.6	61.7	77.3
Gas	**23.5**	24.0	17.8	28.0	15.3
Purchased power —					
From non-affiliates	**40.2**	22.3	13.2	2.2	2.6
From affiliates	**1.7**	4.3	4.4	8.1	4.8
Total	**100.0**	100.0	100.0	100.0	100.0

* Beginning in 2012, plant availability is calculated as a weighted equivalent availability.

DIRECTORS

S. W. Connally, Jr. (1)
President and Chief Executive Officer
Gulf Power Company
Pensacola, Florida. Elected 2012

Mark A. Crosswhite (2)
President and Chief Executive Officer
Gulf Power Company
Pensacola, Florida. Elected 2010

Allan G. Bense
Chairman and Chief Executive Officer
Bense Enterprises, Inc.
Panama City, Florida. Elected 2010

Deborah H. Calder
SVP, Greater Pensacola Operations
Navy Federal Credit Union
Pensacola, Florida. Elected 2010

William C. Cramer, Jr.
President
Bill Cramer Chevrolet Cadillac Buick GMC, Inc.
Panama City, Florida. Elected 2002

J. Mort O'Sullivan, III
Managing Member
Warren Averett O'Sullivan Creel
Pensacola, Florida. Elected 2010

William A. Pullum (3)
Broker/President
Bill Pullum Realty, Inc.
Navarre, Florida. Elected 2001

Winston E. Scott
Senior Vice President for External Relations & Economic Development
Florida Institute of Technology
Melbourne, Florida. Elected 2003

OFFICERS

S. W. Connally, Jr. (1)
President and Chief Executive Officer
24 Years of Service

Mark A. Crosswhite (2)
President and Chief Executive Officer
8 Years of Service

Michael L. Burroughs
Vice President – Sr. Production Officer
21 Years of Service

P. Bernard Jacob
Vice President – Customer Operations
30 Years of Service

Richard S. Teel
Vice President and Chief Financial Officer
13 Years of Service

Bentina C. Terry
Vice President – External Affairs and Corporate Services
11 Years of Service

Connie J. Erickson
Comptroller
10 Years of Service

Susan D. Ritenour
Secretary and Treasurer
31 Years of Service

Terry A. Davis
Assistant Secretary and Assistant Treasurer
26 Years of Service

Stacy R. Kilcoyne
Vice President
35 Years of Service

Melissa K. Caen
Assistant Secretary and Assistant Treasurer
6 Years of Service

(1) Elected effective July 1, 2012.
(2) Resigned effective July 1, 2012.
(3) Retired effective May 14, 2012.

General
This annual report is submitted for general information. It is not intended for use in connection with any sale or purchase of, or any solicitation of offers to buy or sell, securities.

Profile
The Company produces and delivers electricity as an integrated utility to both retail and wholesale customers within the State of Florida. The Company sells electricity to approximately 435,000 customers within its service area of approximately 7,500 square miles in the Florida panhandle. In 2012, retail energy sales accounted for 67 percent of the Company's total sales of 16 billion kilowatt-hours.

The Company is a wholly owned subsidiary of The Southern Company, which is the parent company of four traditional operating companies, a wholesale generation subsidiary, and other direct and indirect subsidiaries. There is no established public trading market for the Company's common stock.

Registrar, Transfer Agent, and Dividend Paying Agent
Preference Stock
Computershare Shareowner Services, LLC
P.O. Box 43006
Providence, RI 02940-3006
(800) 554-7626

www.computershare.com/investor

Trustee, Registrar, and Interest Paying Agent
All series of Senior Notes
The Bank of New York Mellon
Global Corporate Trust
900 Ashford Center North, Suite 425
Atlanta, Georgia 30338

All of the outstanding shares of the Company's preference stock are registered in the name of Cede & Co., as nominee for The Depository Trust Company.

Form 10-K
A copy of Form 10-K as filed with the Securities and Exchange Commission will be provided upon written request to the office of the Corporate Secretary at the mailing address below:

Corporate Office
Principal Address & Deliveries:
Gulf Power Company
500 Bayfront Parkway
Pensacola, FL 32520
(850) 444-6111

Mailing Address:
Gulf Power Company
One Energy Place
Pensacola, FL 32520

Auditors
Deloitte & Touche LLP
Suite 1500
191 Peachtree Street, N.E.
Atlanta, GA 30303-1924

Legal Counsel
Beggs & Lane
A Registered Limited Liability Partnership
P.O. Box 12950
Pensacola, FL 32591-2950

Schedule F-2	SEC REPORTS	Page 1 of 1
FLORIDA PUBLIC SERVICE COMMISSION	EXPLANATION: Provide a copy of the most recent Form 10-K annual report to the Securities and Exchange Commission and all Form 10-Q quarterly reports filed subsequent to the filing of the latest 10-K.	Type of Data Shown: ___Projected Test Year Ended 12/31/14 ___Prior Year Ended 12/31/13 _X_Historical Year Ended 12/31/12 Witness: R. S. Teel, C. J. Erickson
COMPANY: GULF POWER COMPANY		
DOCKET NO.: 130140-EI		

Line No.	
1	See Attached

Supporting Schedules:

Recap Schedules:

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

☑ QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended March 31, 2013
OR
☐ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from _____to_____

Commission File Number	Registrant, State of Incorporation, Address and Telephone Number	I.R.S. Employer Identification No.
1-3526	**The Southern Company** (A Delaware Corporation) 30 Ivan Allen Jr. Boulevard, N.W. Atlanta, Georgia 30308 (404) 506-5000	58-0690070
1-3164	**Alabama Power Company** (An Alabama Corporation) 600 North 18th Street Birmingham, Alabama 35203 (205) 257-1000	63-0004250
1-6468	**Georgia Power Company** (A Georgia Corporation) 241 Ralph McGill Boulevard, N.E. Atlanta, Georgia 30308 (404) 506-6526	58-0257110
001-31737	**Gulf Power Company** (A Florida Corporation) One Energy Place Pensacola, Florida 32520 (850) 444-6111	59-0276810
001-11229	**Mississippi Power Company** (A Mississippi Corporation) 2992 West Beach Boulevard Gulfport, Mississippi 39501 (228) 864-1211	64-0205820
333-98553	**Southern Power Company** (A Delaware Corporation) 30 Ivan Allen Jr. Boulevard, N.W. Atlanta, Georgia 30308 (404) 506-5000	58-2598670

Indicate by check mark whether the registrants (1) have filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrants were required to file such reports), and (2) have been subject to such filing requirements for the past 90 days. Yes ☑ No ☐

Indicate by check mark whether the registrants have submitted electronically and posted on their corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrants were required to submit and post such files). Yes ☑ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Registrant	Large Accelerated Filer	Accelerated Filer	Non-accelerated Filer	Smaller Reporting Company
The Southern Company	X			
Alabama Power Company			X	
Georgia Power Company			X	
Gulf Power Company			X	
Mississippi Power Company			X	
Southern Power Company			X	

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act.) Yes ☐ No ☑ (Response applicable to all registrants.)

Registrant	Description of Common Stock	Shares Outstanding at March 31, 2013
The Southern Company	**Par Value $5 Per Share**	**870,390,537**
Alabama Power Company	**Par Value $40 Per Share**	**30,537,500**
Georgia Power Company	**Without Par Value**	**9,261,500**
Gulf Power Company	**Without Par Value**	**4,942,717**
Mississippi Power Company	**Without Par Value**	**1,121,000**
Southern Power Company	**Par Value $0.01 Per Share**	**1,000**

This combined Form 10-Q is separately filed by The Southern Company, Alabama Power Company, Georgia Power Company, Gulf Power Company, Mississippi Power Company, and Southern Power Company. Information contained herein relating to any individual registrant is filed by such registrant on its own behalf. Each registrant makes no representation as to information relating to the other registrants.

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March 31, 2013

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DEFINITIONS

Term	Meaning
2010 ARP	Alternate Rate Plan approved by the Georgia PSC for Georgia Power, which became effective January 1, 2011 and will continue through December 31, 2013
2011 IRP	Georgia Power's 2011 Integrated Resource Plan update filed with the Georgia PSC
2013 IRP	Georgia Power's triennial Integrated Resource Plan filed with the Georgia PSC on January 31, 2013
AFUDC	Allowance for Funds Used During Construction
Alabama Power	Alabama Power Company
AOCI	Accumulated Other Comprehensive Income
Baseload Act	State of Mississippi legislation designed to enhance the Mississippi PSC's authority to facilitate development and construction of baseload generation in the State of Mississippi
Clean Air Act	Clean Air Act Amendments of 1990
Contractor	Westinghouse and Stone & Webster, Inc.
CPCN	Certificate of Public Convenience and Necessity
CWIP	Construction Work in Progress
DOE	U.S. Department of Energy
ECO Plan	Mississippi Power's Environmental Compliance Overview Plan
EPA	U.S. Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
Form 10-K	Combined Annual Report on Form 10-K of Southern Company, Alabama Power, Georgia Power, Gulf Power, and Southern Power for the year ended December 31, 2012
Form 10-K/A	Annual Report on Form 10-K of Mississippi Power for the year ended December 31, 2012, as amended by Amendment No. 1
GAAP	Generally Accepted Accounting Principles
Georgia Power	Georgia Power Company
Gulf Power	Gulf Power Company
IFR	Georgia Power's Interim Fuel Rider
IIC	Intercompany Interchange Contract
Internal Revenue Code	Internal Revenue Code of 1986, as amended
IRS	Internal Revenue Service
Kemper IGCC	Integrated coal gasification combined cycle facility under construction in Kemper County, Mississippi
KWH	Kilowatt-hour
LIBOR	London Interbank Offered Rate
MATS rule	Mercury and Air Toxics Standards Rule
Mississippi Power	Mississippi Power Company
mmBtu	Million British thermal unit
Moody's	Moody's Investors Service, Inc.
MW	Megawatt
MWH	Megawatt-hour
NCCR	Georgia Power's Nuclear Construction Cost Recovery
NDR	Alabama Power's Natural Disaster Reserve
NRC	Nuclear Regulatory Commission
NSR	New Source Review
OCI	Other Comprehensive Income

Owners	Georgia Power, Oglethorpe Power Corporation, the Municipal Electric Authority of Georgia, and the City of Dalton, Georgia, an incorporated municipality in the State of Georgia acting by and through its Board of Water, Light, and Sinking Fund Commissioners
PEP	Mississippi Power's Performance Evaluation Plan
Plant Vogtle Units 3 and 4	Two new nuclear generating units under construction at Plant Vogtle
Power Pool	The operating arrangement whereby the integrated generating resources of the traditional operating companies and Southern Power are subject to joint commitment and dispatch in order to serve their combined load obligations
PPA	Power Purchase Agreement
PSC	Public Service Commission
registrants	Southern Company, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, and Southern Power
ROE	Return on Equity
SEC	Securities and Exchange Commission
SEGCO	Southern Electric Generating Company
SMEPA	South Mississippi Electric Power Association
Southern Company	The Southern Company
Southern Company system	Southern Company, the traditional operating companies, Southern Power, and other subsidiaries
Southern Nuclear	Southern Nuclear Operating Company, Inc.
Southern Power	Southern Power Company
S&P	Standard and Poor's Ratings Services, a division of The McGraw Hill Companies, Inc.
traditional operating companies	Alabama Power, Georgia Power, Gulf Power, and Mississippi Power
Westinghouse	Westinghouse Electric Company LLC
wholesale revenues	revenues generated from sales for resale

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

This Quarterly Report on Form 10-Q contains forward-looking statements. Forward-looking statements include, among other things, statements concerning retail sales, retail rates, the strategic goals for the wholesale business, customer growth, economic recovery, fuel and environmental cost recovery and other rate actions, current and proposed environmental regulations and related estimated expenditures, access to sources of capital, projections for the qualified pension plan, postretirement benefit plan, and nuclear decommissioning trust fund contributions, financing activities, start and completion dates of construction projects, plans and estimated costs for new generation resources, filings with state and federal regulatory authorities, impact of the American Taxpayer Relief Act of 2012, estimated sales and purchases under new power sale and purchase agreements, and estimated construction and other expenditures. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "could," "should," "expects," "plans," "anticipates," "believes," "estimates," "projects," "predicts," "potential," or "continue" or the negative of these terms or other similar terminology. There are various factors that could cause actual results to differ materially from those suggested by the forward-looking statements; accordingly, there can be no assurance that such indicated results will be realized. These factors include:

- the impact of recent and future federal and state regulatory changes, including legislative and regulatory initiatives regarding deregulation and restructuring of the electric utility industry, environmental laws including regulation of water, coal combustion byproducts, and emissions of sulfur, nitrogen, carbon, soot, particulate matter, hazardous air pollutants, including mercury, and other substances, financial reform legislation, and also changes in tax and other laws and regulations to which Southern Company and its subsidiaries are subject, as well as changes in application of existing laws and regulations;
- current and future litigation, regulatory investigations, proceedings, or inquiries, including the pending EPA civil actions against certain Southern Company subsidiaries, FERC matters, and IRS and state tax audits;
- the effects, extent, and timing of the entry of additional competition in the markets in which Southern Company's subsidiaries operate;
- variations in demand for electricity, including those relating to weather, the general economy and recovery from the recent recession, population and business growth (and declines), the effects of energy conservation measures, and any potential economic impacts resulting from federal fiscal decisions;
- available sources and costs of fuels;
- effects of inflation;
- ability to control costs and avoid cost overruns during the development and construction of facilities, including the development and construction of facilities with designs that have not been finalized or previously constructed, to construct facilities in accordance with the requirements of permits and licenses, and to satisfy any operational and environmental performance standards, including the requirements of tax credits and other incentives;
- investment performance of Southern Company's employee benefit plans and the Southern Company system's nuclear decommissioning trust funds;
- advances in technology;
- state and federal rate regulations and the impact of pending and future rate cases and negotiations, including rate actions relating to fuel and other cost recovery mechanisms;
- regulatory approvals and actions related to Plant Vogtle Units 3 and 4, including Georgia PSC approvals, NRC actions, and potential DOE loan guarantees;
- regulatory approvals and actions related to cost recovery for the Kemper IGCC, including Mississippi PSC review of Mississippi Power's proposed rate recovery plan, the prudence review of Kemper IGCC costs and actions relating to proposed securitization; the ability to complete the proposed sale of an interest in the Kemper IGCC to SMEPA as contemplated by Mississippi Power's proposed rate recovery plan; satisfaction of requirements to utilize investment tax credits and grants; and the outcome of any legal or regulatory proceedings regarding the Mississippi PSC's issuance of the CPCN for the Kemper IGCC, the settlement agreement between Mississippi Power and the Mississippi PSC, or the Baseload Act;

- the inherent risks involved in operating and constructing nuclear generating facilities, including environmental, health, regulatory, natural disaster, terrorism, and financial risks;
- the performance of projects undertaken by the non-utility businesses and the success of efforts to invest in and develop new opportunities;
- internal restructuring or other restructuring options that may be pursued;
- potential business strategies, including acquisitions or dispositions of assets or businesses, which cannot be assured to be completed or beneficial to Southern Company or its subsidiaries;
- the ability of counterparties of Southern Company and its subsidiaries to make payments as and when due and to perform as required;
- the ability to obtain new short- and long-term contracts with wholesale customers;
- the direct or indirect effect on the Southern Company system's business resulting from terrorist incidents and the threat of terrorist incidents, including cyber intrusion;
- interest rate fluctuations and financial market conditions and the results of financing efforts, including Southern Company's and its subsidiaries' credit ratings;
- the impacts of any potential U.S. credit rating downgrade or other sovereign financial issues, including impacts on interest rates, access to capital markets, impacts on currency exchange rates, counterparty performance, and the economy in general, as well as potential impacts on the availability or benefits of proposed DOE loan guarantees;
- the ability of Southern Company and its subsidiaries to obtain additional generating capacity at competitive prices;
- catastrophic events such as fires, earthquakes, explosions, floods, hurricanes, droughts, pandemic health events such as influenzas, or other similar occurrences;
- the direct or indirect effects on the Southern Company system's business resulting from incidents affecting the U.S. electric grid or operation of generating resources;
- the effect of accounting pronouncements issued periodically by standard setting bodies; and
- other factors discussed elsewhere herein and in other reports (including the Form 10-K and the Form 10-K/A) filed by the registrants from time to time with the SEC.

The registrants expressly disclaim any obligation to update any forward-looking statements.

THE SOUTHERN COMPANY AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME (UNAUDITED)

	For the Three Months Ended March 31,	
	2013	2012
	(in millions)	
Operating Revenues:		
Retail revenues	**$ 3,298**	$ 3,092
Wholesale revenues	**432**	349
Other electric revenues	**155**	148
Other revenues	**12**	15
Total operating revenues	**3,897**	3,604
Operating Expenses:		
Fuel	**1,262**	1,064
Purchased power	**95**	141
Other operations and maintenance	**974**	967
Depreciation and amortization	**466**	441
Taxes other than income taxes	**235**	225
Estimated loss on Kemper IGCC	**540**	—
Total operating expenses	**3,572**	2,838
Operating Income	**325**	766
Other Income and (Expense):		
Allowance for equity funds used during construction	**41**	31
Leveraged lease income (loss)	**(21)**	6
Interest expense, net of amounts capitalized	**(211)**	(211)
Other income (expense), net	**(6)**	(8)
Total other income and (expense)	**(197)**	(182)
Earnings Before Income Taxes	**128**	584
Income taxes	**31**	200
Consolidated Net Income	**97**	384
Dividends on Preferred and Preference Stock of Subsidiaries	**16**	16
Consolidated Net Income After Dividends on Preferred and Preference Stock of Subsidiaries	**$ 81**	$ 368
Common Stock Data:		
Earnings per share (EPS) -		
Basic EPS	**$ 0.09**	$ 0.42
Diluted EPS	**$ 0.09**	$ 0.42
Average number of shares of common stock outstanding (in millions)		
Basic	**870**	868
Diluted	**875**	877
Cash dividends paid per share of common stock	**$ 0.4900**	$ 0.4725

The accompanying notes as they relate to Southern Company are an integral part of these condensed financial statements.

THE SOUTHERN COMPANY AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (UNAUDITED)

	For the Three Months Ended March 31,	
	2013	2012
	(in millions)	
Consolidated Net Income	**$ 97**	$ 384
Other comprehensive income (loss):		
Qualifying hedges:		
Changes in fair value, net of tax of $- and $2, respectively	**—**	3
Reclassification adjustment for amounts included in net income, net of tax of $2 and $1, respectively	**3**	2
Pension and other post retirement benefit plans:		
Reclassification adjustment for amounts included in net income, net of tax of $1 and $1, respectively	**1**	1
Total other comprehensive income (loss)	**4**	6
Dividends on preferred and preference stock of subsidiaries	**(16)**	(16)
Comprehensive Income	**$ 85**	$ 374

The accompanying notes as they relate to Southern Company are an integral part of these condensed financial statements.

THE SOUTHERN COMPANY AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)

	For the Three Months Ended March 31,	
	2013	2012
	(in millions)	
Operating Activities:		
Consolidated net income	**$ 97**	$ 384
Adjustments to reconcile consolidated net income to net cash provided from operating activities —		
Depreciation and amortization, total	**568**	529
Deferred income taxes	**(92)**	104
Allowance for equity funds used during construction	**(41)**	(31)
Leveraged lease (income) loss	**21**	(6)
Pension, postretirement, and other employee benefits	**22**	16
Stock based compensation expense	**26**	25
Estimated loss on Kemper IGCC	**540**	—
Other, net	**(62)**	8
Changes in certain current assets and liabilities —		
-Receivables	**29**	372
-Fossil fuel stock	**36**	(218)
-Materials and supplies	**52**	4
-Other current assets	**(72)**	(64)
-Accounts payable	**(47)**	(136)
-Accrued taxes	**(98)**	(167)
-Accrued compensation	**(282)**	(305)
-Other current liabilities	**40**	53
Net cash provided from operating activities	**737**	568
Investing Activities:		
Property additions	**(1,197)**	(1,231)
Investment in restricted cash	**(78)**	1
Nuclear decommissioning trust fund purchases	**(262)**	(336)
Nuclear decommissioning trust fund sales	**261**	334
Cost of removal, net of salvage	**(30)**	(32)
Change in construction payables, net	**6**	(153)
Other investing activities	**21**	(10)
Net cash used for investing activities	**(1,279)**	(1,427)
Financing Activities:		
Increase in notes payable, net	**468**	174
Proceeds —		
Long-term debt issuances	**1,035**	1,400
Interest-bearing refundable deposit related to asset sale	**—**	150
Common stock issuances	**42**	116
Redemptions —		
Long-term debt	**(656)**	(827)
Common stock repurchased	**(18)**	—
Payment of common stock dividends	**(426)**	(410)
Payment of dividends on preferred and preference stock of subsidiaries	**(16)**	(16)
Other financing activities	**—**	1
Net cash provided from financing activities	**429**	588
Net Change in Cash and Cash Equivalents	**(113)**	(271)
Cash and Cash Equivalents at Beginning of Period	**628**	1,315
Cash and Cash Equivalents at End of Period	**$ 515**	$ 1,044
Supplemental Cash Flow Information:		
Cash paid (received) during the period for —		
Interest (net of $17 and $21 capitalized for 2013 and 2012, respectively)	**$ 187**	$ 178
Income taxes, net	**4**	2
Noncash transactions — accrued property additions at end of period	**501**	420

The accompanying notes as they relate to Southern Company are an integral part of these condensed financial statements.

THE SOUTHERN COMPANY AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED BALANCE SHEETS (UNAUDITED)

Assets	At March 31, 2013	At December 31, 2012
	(in millions)	
Current Assets:		
Cash and cash equivalents	**$ 515**	$ 628
Restricted cash and cash equivalents	**25**	7
Receivables —		
Customer accounts receivable	**1,011**	961
Unbilled revenues	**390**	441
Under recovered regulatory clause revenues	**26**	29
Other accounts and notes receivable	**223**	235
Accumulated provision for uncollectible accounts	**(15)**	(17)
Fossil fuel stock, at average cost	**1,783**	1,819
Materials and supplies, at average cost	**940**	1,000
Vacation pay	**166**	165
Prepaid expenses	**693**	657
Other regulatory assets, current	**115**	163
Other current assets	**60**	74
Total current assets	**5,932**	6,162
Property, Plant, and Equipment:		
In service	**63,586**	63,251
Less accumulated depreciation	**22,219**	21,964
Plant in service, net of depreciation	**41,367**	41,287
Other utility plant, net	**266**	263
Nuclear fuel, at amortized cost	**861**	851
Construction work in progress	**6,193**	5,989
Total property, plant, and equipment	**48,687**	48,390
Other Property and Investments:		
Nuclear decommissioning trusts, at fair value	**1,365**	1,303
Leveraged leases	**648**	670
Miscellaneous property and investments	**217**	216
Total other property and investments	**2,230**	2,189
Deferred Charges and Other Assets:		
Deferred charges related to income taxes	**1,387**	1,385
Unamortized debt issuance expense	**144**	133
Unamortized loss on reacquired debt	**303**	309
Other regulatory assets, deferred	**4,021**	4,032
Other deferred charges and assets	**570**	549
Total deferred charges and other assets	**6,425**	6,408
Total Assets	**$ 63,274**	$ 63,149

The accompanying notes as they relate to Southern Company are an integral part of these condensed financial statements.

THE SOUTHERN COMPANY AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED BALANCE SHEETS (UNAUDITED)

Liabilities and Stockholders' Equity	At March 31, 2013	At December 31, 2012
	(in millions)	
Current Liabilities:		
Securities due within one year	**$ 1,769**	$ 2,335
Interest-bearing refundable deposit related to asset sale	**150**	150
Notes payable	**1,294**	825
Accounts payable	**1,369**	1,387
Customer deposits	**376**	370
Accrued taxes —		
Accrued income taxes	**38**	10
Other accrued taxes	**208**	391
Accrued interest	**249**	237
Accrued vacation pay	**212**	212
Accrued compensation	**161**	433
Liabilities from risk management activities	**37**	75
Other regulatory liabilities, current	**114**	107
Other current liabilities	**462**	482
Total current liabilities	**6,439**	7,014
Long-term Debt	**20,223**	19,274
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	**9,842**	9,938
Deferred credits related to income taxes	**207**	211
Accumulated deferred investment tax credits	**946**	894
Employee benefit obligations	**2,526**	2,540
Asset retirement obligations	**1,807**	1,748
Other cost of removal obligations	**1,220**	1,194
Other regulatory liabilities, deferred	**312**	289
Other deferred credits and liabilities	**633**	668
Total deferred credits and other liabilities	**17,493**	17,482
Total Liabilities	**44,155**	43,770
Redeemable Preferred Stock of Subsidiaries	**375**	375
Stockholders' Equity:		
Common Stockholders' Equity:		
Common stock, par value $5 per share —		
Authorized — 1.5 billion shares		
Issued — March 31, 2013: 880 million shares		
— December 31, 2012: 878 million shares		
Treasury — March 31, 2013: 10.1 million shares		
— December 31, 2012: 10.0 million shares		
Par value	**4,400**	4,389
Paid-in capital	**4,926**	4,855
Treasury, at cost	**(451)**	(450)
Retained earnings	**9,281**	9,626
Accumulated other comprehensive loss	**(119)**	(123)
Total Common Stockholders' Equity	**18,037**	18,297
Preferred and Preference Stock of Subsidiaries	**707**	707
Total Stockholders' Equity	**18,744**	19,004
Total Liabilities and Stockholders' Equity	**$ 63,274**	$ 63,149

The accompanying notes as they relate to Southern Company are an integral part of these condensed financial statements.

OVERVIEW

Southern Company is a holding company that owns all of the common stock of the traditional operating companies – Alabama Power, Georgia Power, Gulf Power, and Mississippi Power – and Southern Power and other direct and indirect subsidiaries. Discussion of the results of operations is focused on the Southern Company system's primary business of electricity sales by the traditional operating companies and Southern Power. The four traditional operating companies are vertically integrated utilities providing electric service in four Southeastern states. Southern Power constructs, acquires, owns, and manages generation assets, including renewable energy projects, and sells electricity at market-based rates in the wholesale market. Southern Company's other business activities include investments in leveraged lease projects and telecommunications. For additional information on these businesses, see BUSINESS – The Southern Company System – "Traditional Operating Companies," "Southern Power," and "Other Businesses" in Item 1 of the Form 10-K.

In addition, subsidiaries of Southern Company are constructing Plant Vogtle Units 3 and 4 (45.7% ownership interest by Georgia Power in two units, each with approximately 1,100 MWs) and the Kemper IGCC for a total of 582 MWs. See RESULTS OF OPERATIONS – "Estimated Loss on Kemper IGCC," FUTURE EARNINGS POTENTIAL – "Construction Program," and Note (B) to the Condensed Financial Statements under "PSC Matters – Georgia Power – Nuclear Construction" and "Integrated Coal Gasification Combined Cycle" herein for additional information.

Georgia Power is scheduled to file its next base rate case by July 1, 2013, which will determine whether the 2010 ARP should be continued, modified, or discontinued.

Southern Company continues to focus on several key performance indicators. These indicators include customer satisfaction, plant availability, system reliability, and earnings per share. For additional information on these indicators, see MANAGEMENT'S DISCUSSION AND ANALYSIS – OVERVIEW – "Key Performance Indicators" of Southern Company in Item 7 of the Form 10-K. See FUTURE EARNINGS POTENTIAL – "Other Matters" herein for information regarding an explosion at Plant Bowen in April 2013 that is expected to negatively impact the Southern Company system's actual performance on its peak season equivalent forced outage rate, one of its key performance indicators, for 2013, as compared to the target.

RESULTS OF OPERATIONS

Net Income

First Quarter 2013 vs. First Quarter 2012	
(change in millions)	*(% change)*
$(287)	(78.0)

Southern Company's first quarter 2013 net income after dividends on preferred and preference stock of subsidiaries was $81 million ($0.09 per share) compared to $368 million ($0.42 per share) for the first quarter 2012. The decrease was primarily related to a revision of estimated costs expected to be incurred on Mississippi Power's construction of the Kemper IGCC above the $2.88 billion cost cap established by the Mississippi PSC, net of $245 million of grants awarded to the project by the DOE under the Clean Coal Power Initiative Round 2 (DOE Grants) and the cost of the lignite mine and equipment, the cost of the carbon dioxide pipeline facilities, AFUDC, and certain general exceptions, including change of law, force majeure, and beneficial capital (which exists when Mississippi Power demonstrates that the purpose and effect of the construction cost increase is to produce efficiencies that will result in a neutral or favorable effect on customers relative to the original proposal for the CPCN) (Cost Cap Exceptions). Also contributing to the decrease were a reduction in leveraged lease income

resulting from a lease restructuring and an increase in depreciation related to new generating plants in service. The decrease was partially offset by an increase in weather-related revenues due to more favorable weather in the first quarter 2013 as compared to the corresponding period in 2012, an increase in retail base revenues at Georgia Power as authorized under the 2010 ARP and the NCCR tariff, and an increase in capacity revenues at Southern Power.

Retail Revenues

First Quarter 2013 vs. First Quarter 2012	
(change in millions)	*(% change)*
$206	6.7

In the first quarter 2013, retail revenues were $3.3 billion compared to $3.1 billion for the corresponding period in 2012.

Details of the change to retail revenues were as follows:

	First Quarter 2013	
	(in millions)	*(% change)*
Retail – prior year	$ 3,092	
Estimated change in –		
Rates and pricing	46	1.5
Sales growth (decline)	(14)	(0.4)
Weather	66	2.1
Fuel and other cost recovery	108	3.5
Retail – current year	$ 3,298	6.7%

Revenues associated with changes in rates and pricing increased in the first quarter 2013 when compared to the corresponding period in 2012 primarily due to base tariff increases at Georgia Power effective April 2012 and January 1, 2013, as approved by the Georgia PSC, related to placing new generating units at Plant McDonough-Atkinson in service, the financing costs related to the construction of Plant Vogtle Units 3 and 4, and demand-side management costs.

Revenues attributable to changes in sales decreased in the first quarter 2013 when compared to the corresponding period in 2012. The decrease was due to a 2.1% decrease in industrial KWH sales and a 0.9% decrease in weather-adjusted residential KWH sales, partially offset by a 0.4% increase in weather-adjusted commercial KWH sales. The decrease in industrial KWH sales for the first quarter 2013 was primarily due to decreases in the chemicals, paper, and primary metals sectors, partially offset by an increase in the stone, clay, and glass sector. The decrease in weather-adjusted residential KWH sales for the first quarter 2013 was primarily due to a decrease in customer usage, partially offset by customer growth. The increase in weather-adjusted commercial KWH sales for the first quarter 2013 was primarily due to increased customer usage. In addition, an extra day of sales as a result of the leap year in 2012 negatively impacted KWH sales in all customer classes in 2013.

In the first quarter 2012, Georgia Power began using new actual advanced meter data to compute unbilled revenues. The weather-adjusted KWH sales variances shown above reflect an adjustment to the estimated allocation of Georgia Power's unbilled January 2012 KWH sales among customer classes that is consistent with the actual allocation in 2013. Without this adjustment, first quarter 2013 residential weather-adjusted KWH sales decreased 1.9% as compared to the corresponding period in 2012 and commercial weather-adjusted KWH sales increased 1.5% as compared to the corresponding period in 2012.

Revenues resulting from changes in weather increased $66 million in the first quarter 2013 as a result of more favorable weather when compared to the corresponding period in 2012.

Fuel and other cost recovery revenues increased $108 million in the first quarter 2013 when compared to the corresponding period in 2012 primarily due to an increase in fuel costs associated with an increase in KWH

generation. Electric rates for the traditional operating companies include provisions to adjust billings for fluctuations in fuel costs, including the energy component of purchased power costs. Under these provisions, fuel revenues generally equal fuel expenses, including the energy component of purchased power costs, and do not affect net income. The traditional operating companies may also have one or more regulatory mechanisms to recover other costs such as environmental, storm damage, new plants, and PPAs.

Wholesale Revenues

First Quarter 2013 vs. First Quarter 2012	
(change in millions)	*(% change)*
$83	23.8

Wholesale revenues consist of PPAs with investor-owned utilities and electric cooperatives, unit power sales contracts, and short-term opportunity sales. Wholesale revenues from PPAs and unit power sales contracts have both capacity and energy components. Capacity revenues reflect the recovery of fixed costs and a return on investment. Energy revenues will vary depending on fuel prices, the market prices of wholesale energy compared to the Southern Company system's generation, demand for energy within the Southern Company system's service territory, and the availability of the Southern Company system's generation. Increases and decreases in energy revenues that are driven by fuel prices are accompanied by an increase or decrease in fuel costs and do not have a significant impact on net income. Short-term opportunity sales are made at market-based rates that generally provide a margin above the Southern Company system's variable cost to produce the energy.

In the first quarter 2013, wholesale revenues were $432 million compared to $349 million for the corresponding period in 2012, reflecting a $60 million increase in energy revenues and a $23 million increase in capacity revenues. The increase in energy revenues was primarily related to more favorable weather in the first quarter 2013 as compared to the corresponding period in 2012. The increase in capacity revenues was primarily due to the commencement of PPAs at Southern Power for new plants placed in service in 2012.

Fuel and Purchased Power Expenses

	First Quarter 2013 vs. First Quarter 2012	
	(change in millions)	*(% change)*
Fuel	$ 198	18.6
Purchased power	(46)	(32.6)
Total fuel and purchased power expenses	$ 152	

In the first quarter 2013, total fuel and purchased power expenses were $1.4 billion compared to $1.2 billion for the corresponding period in 2012. The increase was primarily the result of a $116 million increase in the volume of KWHs generated as a result of more favorable weather in the first quarter 2013 and a $95 million increase in the average cost of fuel and purchased power, partially offset by a $59 million decrease in the volume of KWHs purchased.

Fuel and purchased power energy transactions at the traditional operating companies are generally offset by fuel revenues and do not have a significant impact on net income. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Retail Fuel Cost Recovery" herein for additional information. Fuel expenses incurred under Southern Power's PPAs are generally the responsibility of the counterparties and do not significantly impact net income.

Details of the Southern Company system's generation and purchased power were as follows:

	First Quarter 2013	First Quarter 2012
Total generation *(billions of KWHs)*	**43**	39
Total purchased power *(billions of KWHs)*	**3**	4
Sources of generation *(percent)* —		
Coal	**34**	35
Nuclear	**17**	19
Gas	**44**	42
Hydro	**5**	4
Cost of fuel, generated *(cents per net KWH)* —		
Coal	**4.14**	4.09
Nuclear	**0.85**	0.80
Gas	**3.11**	2.77
Average cost of fuel, generated *(cents per net KWH)*	**3.08**	2.85
Average cost of purchased power *(cents per net KWH)*[a]	**4.64**	3.88

(a) Average cost of purchased power includes fuel purchased by the electric utilities for tolling agreements where power is generated by the provider.

Fuel

In the first quarter 2013, fuel expense was $1.3 billion compared to $1.1 billion for the corresponding period in 2012. The increase was primarily due to a 12.3% increase in the average cost of natural gas per KWH generated and a 9.3% increase in the volume of KWHs generated as a result of higher demand for generation.

Purchased Power

In the first quarter 2013, purchased power expense was $95 million compared to $141 million for the corresponding period in 2012. The decrease was primarily due to a 33.7% decrease in the volume of KWHs purchased as the marginal cost of generation available was lower than the market cost of available energy, partially offset by a 19.6% increase in the average cost per KWH purchased.

Energy purchases will vary depending on demand for energy within the Southern Company system's service territory, the market prices of wholesale energy as compared to the cost of the Southern Company system's generation, and the availability of the Southern Company system's generation.

Other Operations and Maintenance Expenses

First Quarter 2013 vs. First Quarter 2012	
(change in millions)	*(% change)*
$7	0.7

In the first quarter 2013, other operations and maintenance expenses were $974 million compared to $967 million for the corresponding period in 2012. The increase was primarily the result of a $14 million increase in administrative and general costs primarily due to an increase in pension costs and a $6 million increase in nuclear production expenses primarily at Alabama Power related to the amortization of nuclear outage expenses, partially offset by a $14 million decrease related to scheduled outage and maintenance costs.

Depreciation and Amortization

First Quarter 2013 vs. First Quarter 2012	
(change in millions)	*(% change)*
$25	5.7

In the first quarter 2013, depreciation and amortization was $466 million compared to $441 million for the corresponding period in 2012. The increase was primarily the result of an increase in depreciation related to additional plant in service due to the completion of Georgia Power's Plant McDonough-Atkinson Units 5 and 6 in April 2012 and October 2012, respectively, additional plant in service at Southern Power, as well as transmission, distribution, and environmental projects. These increases were partially offset by amortization of the regulatory liability previously established for state income tax credits at Georgia Power, as authorized by the Georgia PSC.

Taxes Other Than Income Taxes

First Quarter 2013 vs. First Quarter 2012	
(change in millions)	*(% change)*
$10	4.4

In the first quarter 2013, taxes other than income taxes were $235 million compared to $225 million for the corresponding period in 2012. The increase was primarily the result of increases in property taxes and municipal franchise fees.

Estimated Loss on Kemper IGCC

First Quarter 2013 vs. First Quarter 2012	
(change in millions)	*(% change)*
$540	N/M

N/M – Not meaningful

In the first quarter 2013, an estimated probable loss on the Kemper IGCC of $540 million was recorded at Southern Company to reflect a revision of estimated costs expected to be incurred on Mississippi Power's construction of the Kemper IGCC in excess of the $2.88 billion cost cap established by the Mississippi PSC, net of the DOE Grants and the Cost Cap Exceptions.

See FUTURE EARNINGS POTENTIAL – "Construction Program" and Note (B) to the Condensed Financial Statements under "Integrated Coal Gasification Combined Cycle" herein for additional information.

Allowance for Equity Funds Used During Construction

First Quarter 2013 vs. First Quarter 2012	
(change in millions)	*(% change)*
$10	32.3

In the first quarter 2013, AFUDC equity was $41 million compared to $31 million for the corresponding period in 2012. The increase was primarily due to an increase in CWIP related to Mississippi Power's Kemper IGCC, partially offset by the completion of Georgia Power's Plant McDonough-Atkinson Units 5 and 6 in April 2012 and October 2012, respectively. See Note (B) to the Condensed Financial Statements under "Integrated Coal Gasification Combined Cycle" herein for additional information regarding the Kemper IGCC.

Leveraged Lease Income (Loss)

First Quarter 2013 vs. First Quarter 2012	
(change in millions)	*(% change)*
$(27)	N/M

N/M – Not meaningful

In the first quarter 2013, leveraged lease income (loss) was $(21) million compared to $6 million for the corresponding period in 2012. The decrease was primarily due to the restructuring of a leveraged lease investment. See Note (J) to the Condensed Financial Statements under "Investments in Leveraged Leases" herein for additional information.

Income Taxes

First Quarter 2013 vs. First Quarter 2012	
(change in millions)	*(% change)*
$(169)	(84.5)

In the first quarter 2013, income taxes were $31 million compared to $200 million for the corresponding period in 2012. The decrease was primarily due to lower pre-tax earnings.

FUTURE EARNINGS POTENTIAL

The results of operations discussed above are not necessarily indicative of Southern Company's future earnings potential. The level of Southern Company's future earnings depends on numerous factors that affect the opportunities, challenges, and risks of the Southern Company system's primary business of selling electricity. These factors include the traditional operating companies' ability to maintain a constructive regulatory environment that continues to allow for the timely recovery of prudently-incurred costs during a time of increasing costs and the successful completion of ongoing construction projects, including construction of generating facilities. Another major factor is the profitability of the competitive wholesale supply business. Future earnings for the electricity business in the near term will depend, in part, upon maintaining energy sales which is subject to a number of factors. These factors include weather, competition, new energy contracts with neighboring utilities and other wholesale customers, energy conservation practiced by customers, the price of electricity, the price elasticity of demand, and the rate of economic growth or decline in the service territory. In addition, the level of future earnings for the wholesale supply business also depends on numerous factors including creditworthiness of customers, total generating capacity available and related costs, future acquisitions and construction of generating facilities, and the successful remarketing of capacity as current contracts expire. Changes in regional and global economic conditions may impact sales for the traditional operating companies and Southern Power, as the pace of the economic recovery remains uncertain. The timing and extent of the economic recovery will impact growth and may impact future earnings. For additional information relating to these issues, see RISK FACTORS in Item 1A and MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL of Southern Company in Item 7 of the Form 10-K.

Environmental Matters

Compliance costs related to federal and state environmental statutes and regulations could affect earnings if such costs cannot continue to be fully recovered in rates on a timely basis. Environmental compliance spending over the next several years may differ materially from the amounts estimated. The timing, specific requirements, and estimated costs could change as environmental statutes and regulations are adopted or modified. Further, higher costs that are recovered through regulated rates could contribute to reduced demand for electricity, which could negatively affect results of operations, cash flows, and financial condition. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters" of Southern Company in

Item 7 and Note 3 to the financial statements of Southern Company under "Environmental Matters" in Item 8 of the Form 10-K for additional information.

Environmental Statutes and Regulations

Air Quality

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations – Air Quality" of Southern Company in Item 7 of the Form 10-K for additional information regarding Alabama's State Implementation Plan requirements related to opacity, the EPA's MATS rule, and the 2007 State of Georgia Multi-Pollutant Rule.

On March 6, 2013, the U.S. Court of Appeals for the Eleventh Circuit upheld the EPA's 2008 approval of Alabama's opacity requirements and vacated the EPA's 2011 attempt to rescind its approval, thereby resolving Alabama Power's appeal in Alabama Power's favor. The ultimate outcome of this matter will depend on the outcome of any further appellate or regulatory actions and cannot be determined at this time.

On April 24, 2013, the EPA published a final reconsideration rule addressing new source standards within the MATS rule. Although the EPA had considered revisions to the startup and shutdown provisions of the MATS rule, a final decision on these provisions was deferred. The ultimate impact of this rulemaking will depend on the outcome of any additional rulemaking and/or legal challenges and, therefore, cannot be determined at this time.

On April 30, 2013, the State of Georgia finalized revisions to the 2007 State of Georgia Multi-Pollutant Rule and a companion rule requiring a 95% reduction in sulfur dioxide emissions from certain coal-fired generating units. The revisions modify the compliance dates under those two rules for units yet to be controlled to synchronize them with the MATS rule compliance deadline. The revisions also allow natural gas to be used as a compliance alternative at Plant Yates as contemplated by the 2013 IRP. The ultimate outcome of these matters cannot be determined at this time. See Note 3 to the financial statements of Southern Company under "Retail Regulatory Matters – Georgia Power – Integrated Resource Plans" in Item 8 of the Form 10-K for additional information.

Water Quality

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations – Water Quality" of Southern Company in Item 7 of the Form 10-K for additional information regarding the EPA's proposed revision of the current steam electric effluent guidelines. On April 19, 2013, the EPA signed a proposed rule which requests comments on a range of potential regulatory options for addressing certain wastestreams from steam electric power plants. These regulations could result in the installation of additional controls at certain of the facilities of Southern Company's subsidiaries, which could result in significant capital expenditures and compliance costs that could affect future unit retirement and replacement decisions. The ultimate impact of these proposed regulations will, however, depend on the specific requirements of the final rule and the outcome of any legal challenges and cannot be determined at this time.

PSC Matters

Retail Fuel Cost Recovery

The traditional operating companies each have established fuel cost recovery rates approved by their respective state PSCs. The traditional operating companies have experienced lower pricing for natural gas in recent years resulting in an increase in natural gas generation and a decrease in coal generation, which is currently more costly. The lower cost of natural gas has resulted in a total over recovered fuel balance at Alabama Power, Georgia Power, Gulf Power, and Mississippi Power included on Southern Company's Condensed Balance Sheet herein of approximately $269 million at March 31, 2013. At December 31, 2012, a total over recovered fuel balance at Georgia Power, Gulf Power, and Mississippi Power included on Southern Company's Condensed Balance Sheet herein was approximately $303 million.

Fuel cost recovery revenues are adjusted for differences in actual recoverable fuel costs and amounts billed in current regulated rates. Accordingly, changes in the billing factor will not have a significant effect on Southern Company's revenues or net income, but will affect cash flow. The traditional operating companies continuously monitor their under or over recovered fuel cost balances.

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "PSC Matters – Fuel Cost Recovery" of Southern Company in Item 7 and Note 3 to the financial statements of Southern Company under "Retail Regulatory Matters – Alabama Power – Energy Cost Recovery" and "Retail Regulatory Matters – Georgia Power – Fuel Cost Recovery" in Item 8 of the Form 10-K for additional information.

Alabama Power

Rate RSE

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "PSC Matters – Alabama Power – Rate RSE" of Southern Company in Item 7 and Note 3 to the financial statements of Southern Company under "Retail Regulatory Matters – Alabama Power – Rate RSE" in Item 8 of the Form 10-K for additional information regarding Alabama Power's Rate Stabilization and Equalization (Rate RSE). On March 19, 2013, the Alabama PSC issued a notice that the Alabama PSC will hold public proceedings regarding the operation and utilization of Rate RSE. The ultimate outcome of these proceedings cannot be determined at this time.

Natural Disaster Cost Recovery

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "PSC Matters – Alabama Power – Natural Disaster Reserve" of Southern Company in Item 7 and Note 3 to the financial statements of Southern Company under "Retail Regulatory Matters – Alabama Power – Natural Disaster Reserve" in Item 8 of the Form 10-K for additional information regarding natural disaster cost recovery. At March 31, 2013, the NDR had an accumulated balance of $93 million as compared to $103 million at December 31, 2012, which is included on Southern Company's Condensed Balance Sheets herein under other regulatory liabilities, deferred. The decrease in the NDR in the first quarter 2013 is a result of storm activity. The related accruals are reflected as operations and maintenance expenses on Southern Company's Condensed Statement of Income herein.

Georgia Power

Integrated Resource Plans

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations – Air Quality," "– Water Quality," and "– Coal Combustion Byproducts" of Southern Company in Item 7 and Note 3 to the financial statements of Southern Company under "Retail Regulatory Matters – Georgia Power – Rate Plans" and "– Integrated Resource Plans" in Item 8 of the Form 10-K for additional information regarding proposed and final EPA rules and regulations, including the MATS rule for coal- and oil-fired electric utility steam generating units, revisions to effluent guidelines for steam electric power plants, and additional regulation of coal combustion byproducts; the State of Georgia's Multi-Pollutant Rule; Georgia Power's analysis of the potential costs and benefits of installing the required controls on its fossil generating units in light of these regulations; the 2010 ARP; the 2011 IRP; and the 2013 IRP.

On April 17, 2013, the Georgia PSC approved the decertification of Plant Bowen Unit 6 (32 MWs), which was retired on April 25, 2013. The Georgia PSC is scheduled to vote on all other aspects of the 2013 IRP in July 2013. The ultimate outcome of this matter cannot be determined at this time.

Separately, on April 22, 2013, Georgia Power executed two PPAs to purchase energy from two wind farms with capacity totaling 250 MWs in southwest Oklahoma that will commence in 2016 and end in 2035. In addition, on April 29, 2013, Georgia Power executed a PPA for the purchase of 50 MWs of capacity and energy that will commence in 2015 and end in 2035. These PPAs are subject to Georgia PSC approval and, if approved, will result in contractual obligations of approximately $13 million in 2015, $47 million in 2016, $48 million in 2017, and $1.3 billion thereafter.

Construction Program

The subsidiary companies of Southern Company are engaged in continuous construction programs to accommodate existing and estimated future loads on their respective systems. The Southern Company system intends to continue its strategy of developing and constructing new generating facilities, including the ongoing construction of Plant Vogtle Units 3 and 4 at Georgia Power, the Kemper IGCC at Mississippi Power, and solar units at Southern Power, as well as adding or changing fuel sources for certain existing units, adding environmental control equipment, and expanding the transmission and distribution systems. For the traditional operating companies, major generation construction projects are subject to state PSC approvals in order to be included in retail rates. While Southern Power generally constructs and acquires generation assets covered by long-term PPAs, any uncontracted capacity could negatively affect future earnings.

The two largest construction projects currently underway in the Southern Company system are Plant Vogtle Units 3 and 4 (45.7% ownership interest by Georgia Power in two units, each with approximately 1,100 MWs) and the construction of Mississippi Power's Kemper IGCC (for a total of 582 MWs). See FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" herein for the current cost estimate of the Southern Company system's construction program, which includes the revised construction cost estimate to complete the Kemper IGCC. Also see Note 3 to the financial statements of Southern Company under "Retail Regulatory Matters – Georgia Power – Nuclear Construction" and "Integrated Coal Gasification Combined Cycle" in Item 8 of the Form 10-K and Note (B) to the Condensed Financial Statements under "Retail Regulatory Matters – Georgia Power – Nuclear Construction" and "Integrated Coal Gasification Combined Cycle" herein for additional information.

Investments in Leveraged Leases

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Investments in Leveraged Leases" of Southern Company in Item 7 and Note 1 to the financial statements of Southern Company under "Leveraged Leases" in Item 8 of the Form 10-K for additional information.

On March 1, 2013, Southern Company completed the restructuring of the nonrecourse debt and the related rental payments associated with its leveraged lease investment in a 440-MW generation facility located in Choctaw County, Mississippi. In connection with the restructuring, Southern Company has committed, as owner/lessor, to invest approximately $60 million in capital over the next three years to improve the operational performance of the facility and upgrade environmental controls. As part of the restructuring, the interest rate on the nonrecourse debt was significantly reduced, resulting in lower debt payments for Southern Company and lower rental payments for the lessee over the remaining 19-year term of the nonrecourse debt and the lease. As a consequence of the restructuring, Southern Company recalculated its net investment in the lease to reflect changes in the future cash flows to Southern Company as owner/lessor. As a result of the recalculation, Southern Company recorded an after-tax charge to income during the first quarter 2013 of approximately $16 million. This noncash charge reflects a reallocation of previously recognized lease income that will be reflected in income over the remaining term of the lease.

Other Matters

Southern Company and its subsidiaries are involved in various other matters being litigated and regulatory matters that could affect future earnings. In addition, Southern Company and its subsidiaries are subject to certain claims and legal actions arising in the ordinary course of business. The business activities of Southern Company's subsidiaries are subject to extensive governmental regulation related to public health and the environment, such as regulation of air emissions and water discharges. Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements, such as air quality and water standards, has increased generally throughout the U.S. In particular, personal injury, property damage, and other claims for damages alleged to have been caused by carbon dioxide and other emissions, coal combustion byproducts, and alleged exposure to hazardous materials, and/or requests for injunctive relief in connection with such matters, have become more frequent.

The ultimate outcome of such pending or potential litigation against Southern Company and its subsidiaries cannot be predicted at this time; however, for current proceedings not specifically reported in Note (B) to the Condensed Financial Statements herein or in Note 3 to the financial statements of Southern Company in Item 8 of the Form 10-K, management does not anticipate that the ultimate liabilities, if any, arising from such current proceedings would have a material effect on Southern Company's financial statements.

See the Notes to the Condensed Financial Statements herein for a discussion of various other contingencies, regulatory matters, and other matters being litigated which may affect future earnings potential.

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Other Matters" of Southern Company in Item 7 of the Form 10-K for additional information regarding the NRC's performance of additional operational and safety reviews of nuclear facilities in the U.S. following the major earthquake and tsunami that struck Japan in 2011. On March 19, 2013, the NRC issued an order relating to hardened vents for certain classes of containment structures, including the one in use at Plant Hatch. Southern Company is continuing to analyze the impact of this order. The ultimate outcome of this matter cannot be determined at this time; however, management does not currently anticipate that the compliance costs associated with this order would have a material impact on Southern Company's financial statements.

On April 4, 2013, an explosion occurred at Plant Bowen Unit 2 that resulted in substantial damage to the Plant Bowen Unit 2 generator, Plant Bowen's Units 1 and 2 control room and surrounding areas, as well as Plant Bowen's switchyard. The extent of the damage sustained by Plant Bowen Unit 1 is unknown. Plant Bowen Units 1 and 2 (approximately 1,400 MWs) remain offline, pending assessment of the damage and completion of repairs. Georgia Power expects that any material repair costs related to the damage will be covered by property insurance. The ultimate outcome of this matter cannot be determined at this time.

ACCOUNTING POLICIES

Application of Critical Accounting Policies and Estimates

Southern Company prepares its consolidated financial statements in accordance with GAAP. Significant accounting policies are described in Note 1 to the financial statements of Southern Company in Item 8 of the Form 10-K. In the application of these policies, certain estimates are made that may have a material impact on Southern Company's results of operations and related disclosures. Different assumptions and measurements could produce estimates that are significantly different from those recorded in the financial statements. See MANAGEMENT'S DISCUSSION AND ANALYSIS – ACCOUNTING POLICIES – "Application of Critical Accounting Policies and Estimates" of Southern Company in Item 7 of the Form 10-K for a complete discussion of Southern Company's critical accounting policies and estimates related to Electric Utility Regulation, Contingent Obligations, and Pension and Other Postretirement Benefits.

Estimated Construction Costs for the Kemper IGCC

On April 23, 2013, Mississippi Power revised its cost estimate to complete construction of the Kemper IGCC to an amount that exceeds the $2.88 billion cost cap, net of the DOE Grants and the Cost Cap Exceptions. Mississippi Power does not intend to seek any joint owner contributions or rate recovery for any Kemper IGCC construction costs that exceed the $2.88 billion cost cap, except for amounts subject to the Cost Cap Exceptions and net of the DOE Grants. As a result, Southern Company recorded a pretax charge of $540 million in the first quarter 2013. In subsequent periods, any changes in the estimated costs to complete construction of the Kemper IGCC subject to the $2.88 billion cost cap will be reflected in Southern Company's statements of income and these changes could be material. Southern Company's analysis will be ongoing throughout the construction period. It is possible that Southern Company could experience further cost increases and/or schedule delays with respect to the Kemper IGCC as a result of factors including, but not limited to, costs and productivity of labor, adverse weather conditions, shortages and inconsistent quality of equipment, materials, and labor, contractor or supplier delay or non-performance under construction or other agreements, delays associated with start-up activities, and/or unforeseen engineering problems.

Given the significant judgment involved in estimating the future costs to complete construction, schedule, and the ultimate rate recoverability for the Kemper IGCC, and the potential impact on Southern Company's results of operations, Southern Company considers the future total construction costs for the Kemper IGCC to be a critical accounting estimate. See FUTURE EARNINGS POTENTIAL – "Construction Program" of Southern Company in Item 7 of the Form 10-K, Note 3 to the financial statements of Southern Company under "Integrated Coal Gasification Combined Cycle" in Item 8 of the Form 10-K, and Note (B) to the Condensed Financial Statements under "Integrated Coal Gasification Combined Cycle" herein for additional information.

FINANCIAL CONDITION AND LIQUIDITY

Overview

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FINANCIAL CONDITION AND LIQUIDITY – "Overview" of Southern Company in Item 7 of the Form 10-K for additional information. Southern Company's financial condition remained stable at March 31, 2013. Southern Company intends to continue to monitor its access to short-term and long-term capital markets as well as its bank credit arrangements to meet future capital and liquidity needs. See "Capital Requirements and Contractual Obligations," "Sources of Capital," and "Financing Activities" herein for additional information.

Net cash provided from operating activities totaled $737 million for the first three months of 2013, an increase of $169 million from the corresponding period in 2012. The increase in net cash provided from operating activities was primarily due to a reduction in fossil fuel stock. Net cash used for investing activities totaled $1.3 billion for the first three months of 2013 primarily due to property additions to utility plant. Net cash provided from financing activities totaled $429 million for the first three months of 2013. This was primarily due to long-term debt issuances. Fluctuations in cash flow from financing activities vary from year to year based on capital needs and the maturity or redemption of securities.

Significant balance sheet changes for the first three months of 2013 include an increase of $297 million in total property, plant, and equipment for construction of generation, transmission, and distribution facilities and a decrease in cash and cash equivalents of $113 million primarily due to an effort to reduce bank balances. Other significant changes include a $949 million increase in long-term debt (excluding amounts due within a year) to repay maturing debt and to fund the Southern Company subsidiaries' continuous construction programs, a $345 million decrease in retained earnings resulting from the estimated probable loss on the Kemper IGCC, a decrease of $272 million in accrued compensation primarily due to the payout in March of employee performance incentives earned in 2012, and a reduction in other accrued taxes of $183 million primarily due to payments of ad valorem taxes.

The market price of Southern Company's common stock at the end of the first quarter 2013 was $46.92 per share (based on the closing price as reported on the New York Stock Exchange) and the book value was $20.72 per share, representing a market-to-book ratio of 226%, compared to $42.81, $21.09, and 203%, respectively, at the end of 2012. The dividend for the first quarter 2013 was $0.49 per share compared to $0.4725 per share in the first quarter 2012. In April 2013, the quarterly dividend payable in June 2013 was increased to $0.5075 per share.

Capital Requirements and Contractual Obligations

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" of Southern Company in Item 7 of the Form 10-K for a description of Southern Company's capital requirements for the construction programs of the Southern Company system, including estimated capital expenditures for new generating facilities and to comply with existing environmental statutes and regulations, and other funding requirements associated with scheduled maturities of long-term debt, as well as the related interest, preferred and preference stock dividends, leases, trust funding requirements, other purchase commitments, unrecognized tax benefits and interest, and derivative obligations. Approximately $1.8 billion will be required through March 31, 2014 to fund maturities of long-term debt. See FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations" herein for additional information.

The Southern Company system's construction program is currently estimated to be $5.9 billion for 2013, $6.0 billion for 2014, and $5.2 billion for 2015. Included in these estimated amounts are expenditures related to the construction of the Kemper IGCC of $913 million and $358 million in 2013 and 2014, respectively, which include the revised construction cost estimate to complete the Kemper IGCC and are net of SMEPA's 15% proposed ownership share of the Kemper IGCC, which reflects costs of approximately $492 million and $28 million in 2013 and 2014, respectively. The estimated share of SMEPA in 2013 reflects estimated construction costs relating to SMEPA's proposed ownership interest to be incurred through December 31, 2013 (including construction costs for all prior years relating to its proposed ownership interest).

The construction programs are subject to periodic review and revision, and actual construction costs may vary from these estimates because of numerous factors. These factors include: changes in business conditions; changes in load projections; changes in the expected environmental compliance program; changes in environmental statutes and regulations; the outcome of any legal challenges to the environmental rules; changes in generating plants, including unit retirements and replacements and adding or changing fuel sources at existing units, to meet regulatory requirements; changes in FERC rules and regulations; PSC approvals; changes in legislation; the cost and efficiency of construction labor, equipment, and materials; project scope and design changes; storm impacts; and the cost of capital. In addition, there can be no assurance that costs related to capital expenditures will be fully recovered. See Note 3 to the financial statements of Southern Company under "Retail Regulatory Matters – Georgia Power – Nuclear Construction" and "Integrated Coal Gasification Combined Cycle" in Item 8 of the Form 10-K and Note (B) to the Condensed Financial Statements under "PSC Matters – Georgia Power – Nuclear Construction" and "Integrated Coal Gasification Combined Cycle" herein for additional information.

Sources of Capital

Southern Company intends to meet its future capital needs through internal cash flow and external security issuances. Equity capital can be provided from any combination of Southern Company's stock plans, private placements, or public offerings. The amount and timing of additional equity capital to be raised in 2013, as well as in subsequent years, will be contingent on Southern Company's investment opportunities.

Except as described herein, the traditional operating companies and Southern Power plan to obtain the funds required for construction and other purposes from sources similar to those used in the past, which were primarily from operating cash flows, security issuances, term loans, short-term borrowings, and equity contributions from Southern Company. However, the amount, type, and timing of any future financings, if needed, will depend upon prevailing market conditions, regulatory approval, and other factors. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FINANCIAL CONDITION AND LIQUIDITY – "Sources of Capital" of Southern Company in Item 7 of the Form 10-K for additional information.

In 2010, Georgia Power reached an agreement with the DOE to accept terms for a conditional commitment for federal loan guarantees that would apply to future Georgia Power borrowings related to the construction of Plant Vogtle Units 3 and 4. Any borrowings guaranteed by the DOE would be full recourse to Georgia Power and secured by a first priority lien on Georgia Power's 45.7% undivided ownership interest in Plant Vogtle Units 3 and 4. Total guaranteed borrowings would not exceed the lesser of 70% of eligible project costs or approximately $3.46 billion and are expected to be funded by the Federal Financing Bank. Final approval and issuance of loan guarantees by the DOE are subject to negotiation of definitive agreements, completion of due diligence by the DOE, receipt of any necessary regulatory approvals, and satisfaction of other conditions. In the event that the DOE does not issue a loan guarantee or Georgia Power determines that the final terms and conditions of the loan guarantee by the DOE are not in the best interest of its customers, Georgia Power expects to finance the construction of Plant Vogtle Units 3 and 4 through traditional capital markets financings. There can be no assurance that the DOE will issue loan guarantees for Georgia Power. The conditional commitment will expire on June 30, 2013, unless further extended by the DOE. See Note (B) to the Condensed Financial Statements under "Retail Regulatory Matters – Georgia Power – Nuclear Construction" herein for additional information regarding Plant Vogtle Units 3 and 4.

Mississippi Power has received DOE Clean Coal Power Initiative Round 2 (CCPI2) grant funds of $245 million that have been used for the construction of the Kemper IGCC. An additional $25 million in CCPI2 grant funds is

expected to be received for the initial operation of the Kemper IGCC. See Note (B) to the Condensed Financial Statements under "Integrated Coal Gasification Combined Cycle" herein for information regarding legislation related to the securitization of certain costs of the Kemper IGCC.

Southern Company's current liabilities frequently exceed current assets because of the continued use of short-term debt as a funding source to meet scheduled maturities of long-term debt, as well as cash needs, which can fluctuate significantly due to the seasonality of the business of the Southern Company system. To meet short-term cash needs and contingencies, Southern Company has substantial cash flow from operating activities and access to capital markets, including commercial paper programs which are backed by bank credit facilities.

At March 31, 2013, Southern Company and its subsidiaries had approximately $515 million of cash and cash equivalents. Committed credit arrangements with banks at March 31, 2013 were as follows:

	Expires[a]						Executable Term Loans		Due Within One Year	
Company	2013	2014	2016	2018	Total	Unused	One Year	Two Years	Term Out	No Term Out
	(in millions)				*(in millions)*		*(in millions)*		*(in millions)*	
Southern Company	$ —	$ —	$ —	$ 1,000	$ 1,000	$ 1,000	$ —	$ —	$ —	$ —
Alabama Power	156	151	—	1,000	1,307	1,307	56	—	56	102
Georgia Power	—	—	150	1,600	1,750	1,740	—	—	—	—
Gulf Power	45	60	165	—	270	270	45	—	45	30
Mississippi Power	110	25	165	—	300	300	25	40	65	70
Southern Power	—	—	—	500	500	500	—	—	—	—
Other	50	—	—	—	50	50	25	—	25	25
Total	$ 361	$ 236	$ 480	$ 4,100	$ 5,177	$ 5,167	$ 151	$ 40	$ 191	$ 227

(a) No credit arrangements expire in 2015 or 2017.

See Note 6 to the financial statements of Southern Company under "Bank Credit Arrangements" in Item 8 of the Form 10-K and Note (E) to the Condensed Financial Statements under "Bank Credit Arrangements" herein for additional information.

A portion of the unused credit with banks is allocated to provide liquidity support to the traditional operating companies' variable rate pollution control revenue bonds and commercial paper programs. The amount of variable rate pollution control revenue bonds outstanding requiring liquidity support as of March 31, 2013 was approximately $1.8 billion.

In February 2013, Southern Company, Alabama Power, Georgia Power, and Southern Power each amended their multi-year credit arrangements, which extended the maturity dates from 2016 to 2018.

In March 2013, Alabama Power amended a $200 million credit arrangement, which extended the maturity date from 2014 to 2018. In March 2013, Gulf Power also amended a $35 million credit arrangement, which reduced the amount to $30 million and extended the maturity date from 2013 to 2014. In addition, in March 2013, Georgia Power, Gulf Power, and Mississippi Power each amended certain of their credit arrangements, which extended the maturity dates from 2014 to 2016 and, in the case of Mississippi Power, also revised the definition of debt to exclude securitized debt relating to the Kemper IGCC for purposes of calculating the debt covenant under these credit arrangements. See Note (B) to the Condensed Financial Statements under "Integrated Coal Gasification Combined Cycle" herein for information regarding legislation related to the securitization of certain costs of the Kemper IGCC.

Subsequent to March 31, 2013, Gulf Power entered into a new credit arrangement for $5 million with a maturity date of 2014.

Subsequent to March 31, 2013, SEGCO entered into two new $25 million credit arrangements with maturity dates of 2014.

Most of these arrangements contain covenants that limit debt levels and typically contain cross default provisions that are restricted only to the indebtedness of the individual company. Southern Company and its subsidiaries are currently in compliance with all such covenants.

The traditional operating companies may also meet short-term cash needs through a Southern Company subsidiary organized to issue and sell commercial paper at the request and for the benefit of each of the traditional operating companies.

Details of short-term borrowings were as follows:

	Short-term Debt at March 31, 2013[a]		Short-term Debt During the Period[a][b]		
	Amount Outstanding	Weighted Average Interest Rate	Average Outstanding	Weighted Average Interest Rate	Maximum Amount Outstanding
	(in millions)		*(in millions)*		*(in millions)*
Commercial paper	$ 989	0.3%	$ 955	0.3%	$ 1,119
Short-term bank debt	300	0.9%	87	0.9%	300
Total	$ 1,289	0.4%	$ 1,042	0.3%	

(a) Excludes notes payable related to other energy service contracts of $2 million.
(b) Average and maximum amounts are based upon daily balances during the three-month period ended March 31, 2013.

Management believes that the need for working capital can be adequately met by utilizing commercial paper programs, lines of credit, and cash.

Credit Rating Risk

Southern Company and its subsidiaries do not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. There are certain contracts that could require collateral, but not accelerated payment, in the event of a credit rating change of certain subsidiaries to BBB and Baa2, or BBB- and/or Baa3 or below. These contracts are for physical electricity purchases and sales, fuel purchases, fuel transportation and storage, emissions allowances, energy price risk management, and construction of new generation.

The maximum potential collateral requirements under these contracts at March 31, 2013 were as follows:

Credit Ratings	Maximum Potential Collateral Requirements
	(in millions)
At BBB and Baa2	$ 9
At BBB- and/or Baa3	625
Below BBB- and/or Baa3	2,571

In March 2012, Mississippi Power received a $150 million interest-bearing refundable deposit from SMEPA to be applied to the sale price for the pending sale of an undivided interest in the Kemper IGCC. Until the acquisition is closed, the deposit bears interest at Mississippi Power's AFUDC rate adjusted for income taxes, which was 9.967% per annum for 2012 and 9.962% per annum at March 31, 2013, and is refundable to SMEPA upon termination of the asset purchase agreement related to such purchase, within 60 days of a request by SMEPA for a full or partial refund, or within 15 days at SMEPA's discretion in the event that Mississippi Power is assigned a

senior unsecured credit rating of BBB+ or lower by S&P or Baa1 or lower by Moody's or ceases to be rated by either of these rating agencies.

Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. Additionally, any credit rating downgrade could impact the ability of Southern Company and its subsidiaries to access capital markets, particularly the short-term debt market and the variable rate pollution control revenue bond market.

Market Price Risk

The Southern Company system is exposed to market risks, primarily commodity price risk and interest rate risk. The Southern Company system may also occasionally have limited exposure to foreign currency exchange rates. To manage the volatility attributable to these exposures, the applicable company nets the exposures, where possible, to take advantage of natural offsets and enters into various derivative transactions for the remaining exposures pursuant to the applicable company's policies in areas such as counterparty exposure and risk management practices. The Southern Company system's policy is that derivatives are to be used primarily for hedging purposes and mandates strict adherence to all applicable risk management policies. Derivative positions are monitored using techniques including, but not limited to, market valuation, value at risk, stress testing, and sensitivity analysis.

Due to cost-based rate regulation and other various cost recovery mechanisms, the traditional operating companies continue to have limited exposure to market volatility in interest rates, foreign currency, commodity fuel prices, and prices of electricity. In addition, Southern Power's exposure to market volatility in commodity fuel prices and prices of electricity is limited because its long-term sales contracts shift substantially all fuel cost responsibility to the purchaser. However, Southern Power has been and may continue to be exposed to market volatility in energy-related commodity prices as a result of sales of uncontracted generating capacity. To mitigate residual risks relative to movements in electricity prices, the traditional operating companies enter into physical fixed-price contracts for the purchase and sale of electricity through the wholesale electricity market and, to a lesser extent, financial hedge contracts for natural gas purchases. The traditional operating companies continue to manage fuel-hedging programs implemented per the guidelines of their respective state PSCs. Southern Company had no material change in market risk exposure for the first quarter 2013 when compared to the December 31, 2012 reporting period.

The changes in fair value of energy-related derivative contracts, the majority of which are composed of regulatory hedges, for the three months ended March 31, 2013 were as follows:

	First Quarter 2013 Changes
	Fair Value
	(in millions)
Contracts outstanding at the beginning of the period, assets (liabilities), net	$ (85)
Contracts realized or settled	25
Current period changes[(a)]	47
Contracts outstanding at the end of the period, assets (liabilities), net	$ (13)

(a) Current period changes also include the changes in fair value of new contracts entered into during the period, if any.

The changes in the fair value positions of the energy-related derivative contracts, which are substantially all attributable to both the volume and the price of natural gas, for the three months ended March 31, 2013 were as follows:

	First Quarter 2013 Changes
	Fair Value
	(in millions)
Natural gas swaps	$ 57
Natural gas options	15
Total changes	$ 72

The net hedge volumes of energy-related derivative contracts were as follows:

	March 31, 2013	December 31, 2012
	mmBtu Volume	
	(in millions)	
Commodity – Natural gas swaps	**170**	171
Commodity – Natural gas options	**89**	105
Total hedge volume	**259**	276

The weighted average swap contract cost above market prices was approximately $0.05 per mmBtu as of March 31, 2013 and $0.39 per mmBtu as of December 31, 2012. The change in option fair value is primarily attributable to the volatility of the market and the underlying change in the natural gas price. The majority of the natural gas hedge gains and losses are recovered through the traditional operating companies' fuel cost recovery clauses.

The net fair value of energy-related derivative contracts by hedge designation was reflected in the financial statements as follows:

Asset (Liability) Derivatives	**March 31, 2013**	December 31, 2012
	(in millions)	
Regulatory hedges	**$ (17)**	$ (86)
Cash flow hedges	**—**	—
Not designated	**4**	1
Total fair value	**$ (13)**	$ (85)

Energy-related derivative contracts which are designated as regulatory hedges relate to the traditional operating companies' fuel-hedging programs, where gains and losses are initially recorded as regulatory liabilities and assets, respectively, and then are included in fuel expense as they are recovered through the fuel cost recovery clauses. Gains and losses on energy-related derivatives that are designated as cash flow hedges are mainly used by Southern Power to hedge anticipated purchases and sales and are initially deferred in OCI before being recognized in income in the same period as the hedged transaction. Gains and losses on energy-related derivative contracts that are not designated or fail to qualify as hedges are recognized in the statements of income as incurred.

Total net unrealized pre-tax gains (losses) recognized in the statements of income for the three months ended March 31, 2013 and 2012 were not material.

Southern Company uses over-the-counter contracts that are not exchange traded but are fair valued using prices which are market observable, and thus fall into Level 2. See Note (C) to the Condensed Financial Statements herein for further discussion on fair value measurements. The maturities of the energy-related derivative contracts, which are all Level 2 of the fair value hierarchy, at March 31, 2013 were as follows:

	March 31, 2013 Fair Value Measurements			
	Total Fair Value	Maturity		
		Year 1	Years 2&3	Years 4&5
		(in millions)		
Level 1	$ —	$ —	$ —	$ —
Level 2	(13)	(8)	(5)	—
Level 3	—	—	—	—
Fair value of contracts outstanding at end of period	$ (13)	$ (8)	$ (5)	$ —

For additional information, see MANAGEMENT'S DISCUSSION AND ANALYSIS – FINANCIAL CONDITION AND LIQUIDITY – "Market Price Risk" of Southern Company in Item 7 and Note 1 under "Financial Instruments" and Note 11 to the financial statements of Southern Company in Item 8 of the Form 10-K and Note (H) to the Condensed Financial Statements herein.

Financing Activities

During the first quarter 2013, Southern Company issued approximately 2.6 million shares of common stock for approximately $54 million through the employee and director stock plans, of which 0.7 million shares related to Southern Company's performance share plan. Since mid-2011, Southern Company has issued additional equity only through its employee and director stock plans. In July 2012, Southern Company announced a program to repurchase shares to partially offset the incremental shares issued under its employee and director stock plans. As of December 31, 2012, Southern Company had repurchased a total of approximately 9 million shares at a total cost of approximately $430 million under this program. In January 2013, Southern Company announced that it plans to continue this program through 2015. There were no repurchases under this program in the first quarter 2013. Pursuant to approval by the Southern Company Board of Directors, Southern Company may repurchase shares through open market purchases or privately negotiated transactions, in accordance with applicable securities laws.

In addition, Southern Company is not currently issuing shares of common stock through the Southern Investment Plan or its employee savings plan. All sales under the Southern Investment Plan and the employee savings plan are currently being funded with shares acquired on the open market by the independent plan administrators.

The following table outlines the long-term debt financing activities for Southern Company, the traditional operating companies, and Southern Power for the first three months of 2013:

Company[a]	Senior Note Issuances	Senior Note Redemptions and Maturities	Revenue Bond Issuances	Other Long-Term Debt Issuances
			(in millions)	
Georgia Power	$ 650	$ 650	$ 18	$ —
Mississippi Power	—	—	16	350
Southern Power	—	—	—	2
Total	$ 650	$ 650	$ 34	$ 352

(a) Southern Company, Alabama Power, and Gulf Power did not issue or redeem any long-term debt during the first quarter 2013.

Southern Company's subsidiaries used the proceeds of the debt issuances shown in the table above for the redemptions and maturities shown in the table above, to repay short-term indebtedness, and for general corporate purposes, including their respective continuous construction programs.

In March 2013, Georgia Power entered into three 60-day floating rate bank loans bearing interest based on one-month LIBOR. Each of these short-term loans was for $100 million aggregate principal amount and the proceeds were used for working capital and other general corporate purposes, including Georgia Power's continuous construction program.

Subsequent to March 31, 2013, $17.5 million aggregate principal amount of Development Authority of Monroe County Pollution Control Revenue Bonds (Georgia Power Company Plant Scherer Project), Second Series 1997 were redeemed.

Also subsequent to March 31, 2013, Southern Power issued a $5.6 million promissory note, due April 30, 2033, to Turner Renewable Energy, LLC related to the financing of the acquisition by Southern Power of Campo Verde Solar, LLC, which is constructing a 139-MW solar photovoltaic facility in Southern California. See Note (I) to the Condensed Financial Statements herein for additional information.

In addition to any financings that may be necessary to meet capital requirements and contractual obligations, Southern Company and its subsidiaries plan to continue, when economically feasible, a program to retire higher-cost securities and replace these obligations with lower-cost capital if market conditions permit.

PART I

Item 3. Quantitative And Qualitative Disclosures About Market Risk.

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FINANCIAL CONDITION AND LIQUIDITY – "Market Price Risk" herein for each registrant and Note 1 to the financial statements of each registrant under "Financial Instruments," Note 11 to the financial statements of Southern Company, Alabama Power, and Georgia Power, Note 10 to the financial statements of Gulf Power and Mississippi Power, and Note 9 to the financial statements of Southern Power in Item 8 of the Form 10-K. Also, see Note (H) to the Condensed Financial Statements herein for information relating to derivative instruments.

Item 4. Controls and Procedures.

(a) Evaluation of disclosure controls and procedures.

Southern Company, Alabama Power, Georgia Power, Gulf Power, and Southern Power

As of the end of the period covered by this quarterly report, Southern Company, Alabama Power, Georgia Power, Gulf Power, and Southern Power conducted separate evaluations under the supervision and with the participation of each company's management, including the Chief Executive Officer and the Chief Financial Officer, of the effectiveness of the design and operation of the disclosure controls and procedures (as defined in Sections 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934). Based upon these evaluations, the Chief Executive Officer and the Chief Financial Officer, in each case, concluded that the disclosure controls and procedures are effective.

Mississippi Power

As described further in Notes 3 and 12 to the financial statements of Mississippi Power in Item 8 and Management's Report on Internal Control Over Financial Reporting in Item 9A of the Form 10-K/A, Mississippi Power restated and corrected its previously issued financial statements for the year ended December 31, 2012 to recognize a pretax charge for an estimated probable loss relating to the Kemper IGCC. Management believes Mississippi Power's failure to maintain sufficient evidence supporting certain estimated amounts included in the Kemper IGCC cost estimate and to fully communicate the related effects in the development of the Kemper IGCC cost estimate would constitute a material weakness in internal control over financial reporting under standards adopted by the Public Company Accounting Oversight Board and concluded Mississippi Power's internal control over financial reporting was not effective as of December 31, 2012.

As of the end of the period covered by this quarterly report, Mississippi Power conducted an evaluation under the supervision and with the participation of management, including the Chief Executive Officer and the Chief Financial Officer, of the effectiveness of the design and operation of the disclosure controls and procedures (as defined in Sections 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934). Based upon this evaluation, which considered the material weakness described above, the Chief Executive Officer and the Chief Financial Officer concluded that the disclosure controls and procedures were not effective.

Management has initiated appropriate actions to remediate the material weakness in internal control over financial reporting. Such actions include, but are not limited to, the following:

- establishing a new governance team focused on accounting, legal, and regulatory affairs that will meet regularly with the Kemper IGCC project and construction teams and will provide further oversight of the Kemper IGCC cost estimation process;
- reemphasizing and enhancing communication across functional areas and departments; and
- applying appropriate performance management actions.

Remediation of the material weakness is expected to be completed during the second quarter 2013.

(b) Changes in internal controls.

There have been no changes in Southern Company's, Alabama Power's, Georgia Power's, Gulf Power's, Mississippi Power's, or Southern Power's internal control over financial reporting (as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934) during the first quarter 2013 that have materially affected or are reasonably likely to materially affect Southern Company's, Alabama Power's, Georgia Power's, Gulf Power's, Mississippi Power's, or Southern Power's internal control over financial reporting.

ALABAMA POWER COMPANY

ALABAMA POWER COMPANY
CONDENSED STATEMENTS OF INCOME (UNAUDITED)

	For the Three Months Ended March 31,	
	2013	2012
	(in millions)	
Operating Revenues:		
Retail revenues	**$ 1,141**	$ 1,092
Wholesale revenues, non-affiliates	**59**	61
Wholesale revenues, affiliates	**56**	14
Other revenues	**52**	49
Total operating revenues	**1,308**	1,216
Operating Expenses:		
Fuel	**372**	306
Purchased power, non-affiliates	**20**	15
Purchased power, affiliates	**31**	40
Other operations and maintenance	**330**	321
Depreciation and amortization	**158**	157
Taxes other than income taxes	**90**	86
Total operating expenses	**1,001**	925
Operating Income	**307**	291
Other Income and (Expense):		
Allowance for equity funds used during construction	**8**	5
Interest expense, net of amounts capitalized	**(66)**	(73)
Other income (expense), net	**(1)**	(3)
Total other income and (expense)	**(59)**	(71)
Earnings Before Income Taxes	**248**	220
Income taxes	**97**	84
Net Income	**151**	136
Dividends on Preferred and Preference Stock	**10**	10
Net Income After Dividends on Preferred and Preference Stock	**$ 141**	$ 126

CONDENSED STATEMENTS OF COMPREHENSIVE INCOME (UNAUDITED)

	For the Three Months Ended March 31,	
	2013	2012
	(in millions)	
Net Income	**$ 151**	$ 136
Other comprehensive income (loss):		
Qualifying hedges:		
Changes in fair value, net of tax of $- and $3, respectively	**—**	4
Total other comprehensive income (loss)	**—**	4
Comprehensive Income	**$ 151**	$ 140

The accompanying notes as they relate to Alabama Power are an integral part of these condensed financial statements.

ALABAMA POWER COMPANY
CONDENSED STATEMENTS OF CASH FLOWS (UNAUDITED)

	For the Three Months Ended March 31,	
	2013	2012
	(in millions)	
Operating Activities:		
Net income	**$ 151**	$ 136
Adjustments to reconcile net income to net cash provided from operating activities —		
Depreciation and amortization, total	**206**	189
Deferred income taxes	**25**	31
Allowance for equity funds used during construction	**(8)**	(5)
Stock based compensation expense	**4**	4
Other, net	**5**	(11)
Changes in certain current assets and liabilities —		
-Receivables	**(13)**	89
-Fossil fuel stock	**28**	(81)
-Materials and supplies	**16**	2
-Other current assets	**(71)**	(51)
-Accounts payable	**(124)**	(149)
-Accrued taxes	**90**	43
-Accrued compensation	**(61)**	(63)
-Retail fuel cost over recovery	**21**	1
-Other current liabilities	**1**	5
Net cash provided from operating activities	**270**	140
Investing Activities:		
Property additions	**(274)**	(244)
Nuclear decommissioning trust fund purchases	**(57)**	(49)
Nuclear decommissioning trust fund sales	**57**	49
Cost of removal, net of salvage	**(9)**	(6)
Change in construction payables	**(1)**	14
Other investing activities	**37**	1
Net cash used for investing activities	**(247)**	(235)
Financing Activities:		
Increase in notes payable, net	**45**	—
Proceeds —		
Capital contributions from parent company	**5**	5
Senior notes issuances	**—**	250
Payment of preferred and preference stock dividends	**(10)**	(10)
Payment of common stock dividends	**(132)**	(135)
Other financing activities	**(3)**	(4)
Net cash provided from (used for) financing activities	**(95)**	106
Net Change in Cash and Cash Equivalents	**(72)**	11
Cash and Cash Equivalents at Beginning of Period	**137**	344
Cash and Cash Equivalents at End of Period	**$ 65**	$ 355
Supplemental Cash Flow Information:		
Cash paid (received) during the period for —		
Interest (net of $3 and $2 capitalized for 2013 and 2012, respectively)	**$ 64**	$ 66
Income taxes, net	**(3)**	22
Noncash transactions—accrued property additions at end of period	**30**	32

The accompanying notes as they relate to Alabama Power are an integral part of these condensed financial statements.

ALABAMA POWER COMPANY
CONDENSED BALANCE SHEETS (UNAUDITED)

Assets	At March 31, 2013	At December 31, 2012
	(in millions)	
Current Assets:		
Cash and cash equivalents	**$ 65**	$ 137
Receivables —		
Customer accounts receivable	**349**	321
Unbilled revenues	**122**	138
Under recovered regulatory clause revenues	**11**	23
Other accounts and notes receivable	**35**	42
Affiliated companies	**74**	55
Accumulated provision for uncollectible accounts	**(8)**	(8)
Fossil fuel stock, at average cost	**447**	475
Materials and supplies, at average cost	**370**	395
Vacation pay	**61**	61
Prepaid expenses	**121**	81
Other regulatory assets, current	**13**	24
Other current assets	**14**	13
Total current assets	**1,674**	1,757
Property, Plant, and Equipment:		
In service	**21,508**	21,407
Less accumulated provision for depreciation	**7,816**	7,761
Plant in service, net of depreciation	**13,692**	13,646
Nuclear fuel, at amortized cost	**356**	354
Construction work in progress	**535**	438
Total property, plant, and equipment	**14,583**	14,438
Other Property and Investments:		
Equity investments in unconsolidated subsidiaries	**54**	53
Nuclear decommissioning trusts, at fair value	**642**	605
Miscellaneous property and investments	**78**	78
Total other property and investments	**774**	736
Deferred Charges and Other Assets:		
Deferred charges related to income taxes	**524**	525
Deferred under recovered regulatory clause revenues	**15**	11
Other regulatory assets, deferred	**1,071**	1,083
Other deferred charges and assets	**128**	162
Total deferred charges and other assets	**1,738**	1,781
Total Assets	**$ 18,769**	$ 18,712

The accompanying notes as they relate to Alabama Power are an integral part of these condensed financial statements.

ALABAMA POWER COMPANY
CONDENSED BALANCE SHEETS (UNAUDITED)

Liabilities and Stockholder's Equity	**At March 31, 2013**	At December 31, 2012
	(in millions)	
Current Liabilities:		
Securities due within one year	**$ 250**	$ 250
Notes payable	**45**	—
Accounts payable —		
Affiliated	**188**	191
Other	**204**	318
Customer deposits	**86**	85
Accrued taxes —		
Accrued income taxes	**73**	5
Other accrued taxes	**56**	33
Accrued interest	**60**	62
Accrued vacation pay	**50**	50
Accrued compensation	**36**	94
Liabilities from risk management activities	**5**	14
Other regulatory liabilities, current	**29**	3
Other current liabilities	**38**	38
Total current liabilities	**1,120**	1,143
Long-term Debt	**5,929**	5,929
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	**3,418**	3,404
Deferred credits related to income taxes	**78**	79
Accumulated deferred investment tax credits	**139**	141
Employee benefit obligations	**319**	321
Asset retirement obligations	**599**	589
Other cost of removal obligations	**773**	759
Other regulatory liabilities, deferred	**203**	183
Other deferred credits and liabilities	**91**	81
Total deferred credits and other liabilities	**5,620**	5,557
Total Liabilities	**12,669**	12,629
Redeemable Preferred Stock	**342**	342
Preference Stock	**343**	343
Common Stockholder's Equity:		
Common stock, par value $40 per share —		
Authorized - 40,000,000 shares		
Outstanding - 30,537,500 shares	**1,222**	1,222
Paid-in capital	**2,236**	2,227
Retained earnings	**1,984**	1,976
Accumulated other comprehensive loss	**(27)**	(27)
Total common stockholder's equity	**5,415**	5,398
Total Liabilities and Stockholder's Equity	**$ 18,769**	$ 18,712

The accompanying notes as they relate to Alabama Power are an integral part of these condensed financial statements.

FIRST QUARTER 2013 vs. FIRST QUARTER 2012

OVERVIEW

Alabama Power operates as a vertically integrated utility providing electricity to retail and wholesale customers within its traditional service territory located within the State of Alabama in addition to wholesale customers in the Southeast. Many factors affect the opportunities, challenges, and risks of Alabama Power's business of selling electricity. These factors include the ability to maintain a constructive regulatory environment, to maintain and grow energy sales given economic conditions, and to effectively manage and secure timely recovery of costs. These costs include those related to projected long-term demand growth, increasingly stringent environmental standards, fuel, capital expenditures, and restoration following major storms. Appropriately balancing required costs and capital expenditures with customer prices will continue to challenge Alabama Power for the foreseeable future.

Alabama Power continues to focus on several key performance indicators. These indicators include customer satisfaction, plant availability, system reliability, and net income after dividends on preferred and preference stock. For additional information on these indicators, see MANAGEMENT'S DISCUSSION AND ANALYSIS – OVERVIEW – "Key Performance Indicators" of Alabama Power in Item 7 of the Form 10-K.

RESULTS OF OPERATIONS

Net Income

First Quarter 2013 vs. First Quarter 2012	
(change in millions)	*(% change)*
$15	11.9

Alabama Power's net income after dividends on preferred and preference stock for the first quarter 2013 was $141 million compared to $126 million for the corresponding period in 2012. The increase for the first quarter 2013 was primarily related to an increase in weather-related revenues due to more favorable weather in the first quarter 2013 as compared to the corresponding period in 2012, partially offset by increases in other operations and maintenance expenses.

Retail Revenues

First Quarter 2013 vs. First Quarter 2012	
(change in millions)	*(% change)*
$49	4.5

In the first quarter 2013, retail revenues were $1.14 billion compared to $1.09 billion for the corresponding period in 2012.

Details of the change to retail revenues were as follows:

	First Quarter 2013	
	(in millions)	*(% change)*
Retail – prior year	$ 1,092	
Estimated change in –		
Rates and pricing	(1)	(0.1)
Sales growth (decline)	(9)	(0.9)
Weather	39	3.6
Fuel and other cost recovery	20	1.9
Retail – current year	$ 1,141	4.5%

Revenues associated with changes in rates and pricing decreased slightly in the first quarter 2013 when compared to the corresponding period in 2012. The decrease was not material.

Revenues attributable to changes in sales decreased in the first quarter 2013 when compared to the corresponding period in 2012. Weather-adjusted residential and commercial KWH energy sales decreased 2.4% and 0.4%, respectively, due to decreases in customer usage. Industrial KWH energy sales increased 0.4% due to an increase in usage resulting from changes in production levels primarily in the stone, clay, and glass and primary metal sectors. In addition, an extra day of sales as a result of the leap year in 2012 negatively impacted KWH sales in all customer classes in 2013.

Revenues resulting from changes in weather increased in the first quarter 2013 when compared to the corresponding period in 2012. Alabama Power's service territory experienced more favorable weather in the first quarter 2013 as compared to the corresponding period in 2012. As a result, residential sales revenues increased 8.5% in the first quarter 2013 as compared to the corresponding period in 2012.

Fuel and other cost recovery revenues increased in the first quarter 2013 when compared to the corresponding period in 2012 primarily due to an increase in fuel costs associated with an increase in KWH generation. Electric rates include provisions to recognize the full recovery of fuel costs, purchased power costs, PPAs certificated by the Alabama PSC, and costs associated with the NDR. Under these provisions, fuel and other cost recovery revenues generally equal fuel and other cost recovery expenses and do not affect net income.

Wholesale Revenues – Non-Affiliates

First Quarter 2013 vs. First Quarter 2012	
(change in millions)	*(% change)*
$(2)	(3.3)

Wholesale revenues from sales to non-affiliates will vary depending on the market prices of available wholesale energy compared to the cost of Alabama Power's and the Southern Company system's generation, demand for energy within the Southern Company system's service territory, and availability of the Southern Company system's generation. Increases and decreases in energy revenues that are driven by fuel prices are accompanied by an increase or decrease in fuel costs and do not have a significant impact on net income.

In the first quarter 2013, the decrease in wholesale revenues from non-affiliates compared to the corresponding period in 2012 was not material.

Wholesale Revenues – Affiliates

First Quarter 2013 vs. First Quarter 2012	
(change in millions)	*(% change)*
$42	300.0

Wholesale revenues from sales to affiliated companies will vary depending on demand and the availability and cost of generating resources at each company. These affiliate sales are made in accordance with the IIC, as approved by the FERC. These transactions do not have a significant impact on earnings since this energy is generally sold at marginal cost and energy purchases are generally offset by energy revenues through Alabama Power's energy cost recovery clauses.

In the first quarter 2013, wholesale revenues from affiliates were $56 million compared to $14 million for the corresponding period in 2012. The increase was primarily due to a 262.4% increase in KWH sales and a 9.5% increase in the price of energy.

Fuel and Purchased Power Expenses

	First Quarter 2013 vs. First Quarter 2012	
	(change in millions)	*(% change)*
Fuel	$ 66	21.6
Purchased power – non-affiliates	5	33.3
Purchased power – affiliates	(9)	(22.5)
Total fuel and purchased power expenses	$ 62	

In the first quarter 2013, total fuel and purchased power expenses were $423 million compared to $361 million for the corresponding period in 2012. The increase was primarily due to a $62 million increase associated with an increase in the volume of KWHs generated as a result of more favorable weather in first quarter 2013, a $5 million increase in the average cost of fuel, and a $4 million increase in the average cost of purchased power, partially offset by an $8 million decrease related to the volume of KWHs purchased.

Fuel and purchased power energy transactions do not have a significant impact on earnings, since energy expenses are generally offset by energy revenues through Alabama Power's energy cost recovery clauses. Alabama Power, along with the Alabama PSC, continuously monitors the under/over recovered balance to determine whether adjustments to billings rates are required. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Retail Energy Cost Recovery" herein for additional information.

Details of Alabama Power's generation and purchased power were as follows:

	First Quarter 2013	First Quarter 2012
Total generation *(billions of KWHs)*	**16**	14
Total purchased power *(billions of KWHs)*	**1**	1
Sources of generation *(percent)* –		
Coal	**47**	42
Nuclear	**24**	27
Gas	**17**	20
Hydro	**12**	11
Cost of fuel, generated *(cents per net KWH)* –		
Coal	**3.35**	3.43
Nuclear	**0.81**	0.74
Gas	**3.31**	3.00
Average cost of fuel, generated *(cents per net KWH)*[(a)]	**2.65**	2.51
Average cost of purchased power *(cents per net KWH)*[(b)]	**4.96**	4.60

(a) KWHs generated by hydro are excluded from the average cost of fuel, generated.
(b) Average cost of purchased power includes fuel purchased by Alabama Power for tolling agreements where power is generated by the provider.

Fuel

In the first quarter 2013, fuel expense was $372 million compared to $306 million for the corresponding period in 2012. The $66 million increase was primarily due to a 31.4% increase in KWHs generated by coal and a 10.3% increase in the average cost of natural gas per KWH generated, which excludes fuel associated with tolling agreements. This increase was offset by a 31.5% increase in the volume of KWHs generated by hydro facilities resulting from greater rainfall.

Purchased Power – Non-Affiliates

In the first quarter 2013, purchased power expense from non-affiliates was $20 million compared to $15 million for the corresponding period in 2012. The increase was related to a 73.0% increase in the amount of energy purchased, partially offset by a 23.4% decrease in the average cost per KWH.

Energy purchases from non-affiliates will vary depending on the market prices of wholesale energy as compared to the cost of the Southern Company system's generation, demand for energy within the Southern Company system's service territory, and the availability of the Southern Company system's generation.

Purchased Power – Affiliates

In the first quarter 2013, purchased power expense from affiliates was $31 million compared to $40 million for the corresponding period in 2012. The decrease was related to a 48.2% decrease in the volume of KWHs purchased, partially offset by a 47.5% increase in the average cost per KWH.

Energy purchases from affiliates will vary depending on demand for energy and the availability and cost of generating resources at each company within the Southern Company system. These purchases are made in accordance with the IIC or other contractual agreements, as approved by the FERC.

Other Operations and Maintenance Expenses

First Quarter 2013 vs. First Quarter 2012	
(change in millions)	*(% change)*
$9	2.8

In the first quarter 2013, other operations and maintenance expenses were $330 million compared to $321 million for the corresponding period in 2012. Nuclear production expenses increased $6 million primarily due to the amortization of nuclear outage expenses. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "PSC Matters – Nuclear Outage Accounting Order" of Alabama Power in Item 7 of the Form 10-K for additional information. Administrative and general expenses increased $3 million primarily due to increases in employee medical and pension expenses, partially offset by a decrease in labor and other general expenses.

Allowance for Funds Used During Construction Equity

First Quarter 2013 vs. First Quarter 2012	
(change in millions)	*(% change)*
$3	60.0

In the first quarter 2013, AFUDC equity was $8 million compared to $5 million for the corresponding period in 2012. The increase was primarily due to an increase in capital expenditures for steam generating and environmental, transmission, and nuclear generating facilities.

Interest Expense, Net of Amounts Capitalized

First Quarter 2013 vs. First Quarter 2012	
(change in millions)	*(% change)*
$(7)	(9.6)

In the first quarter 2013, interest expense, net of amounts capitalized was $66 million compared to $73 million for the corresponding period in 2012. The decrease was primarily due to a decrease in interest rates and the timing of issuances and redemptions of long term-debt.

Other Income (Expense), Net

First Quarter 2013 vs. First Quarter 2012	
(change in millions)	*(% change)*
$2	66.7

In the first quarter 2013, other income (expense), net was $(1) million compared to $(3) million for the corresponding period in 2012. The change was primarily due to an increase in non-operating income related to gains on sales of non-utility property.

Income Taxes

First Quarter 2013 vs. First Quarter 2012	
(change in millions)	*(% change)*
$13	15.5

In the first quarter 2013, income taxes were $97 million compared to $84 million for the corresponding period in 2012. The increase was primarily due to higher pre-tax income as a result of increased weather-related revenues.

FUTURE EARNINGS POTENTIAL

The results of operations discussed above are not necessarily indicative of Alabama Power's future earnings potential. The level of Alabama Power's future earnings depends on numerous factors that affect the opportunities, challenges, and risks of Alabama Power's primary business of selling electricity. These factors include Alabama Power's ability to maintain a constructive regulatory environment that continues to allow for the timely recovery of prudently incurred costs during a time of increasing costs. Future earnings in the near term will depend, in part, upon maintaining energy sales which is subject to a number of factors. These factors include weather, competition, new energy contracts with neighboring utilities, energy conservation practiced by customers, the price of electricity, the price elasticity of demand, and the rate of economic growth or decline in Alabama Power's service territory. Changes in regional and global economic conditions may impact sales for Alabama Power as the pace of the economic recovery remains uncertain. The timing and extent of the economic recovery will impact growth and may impact future earnings. For additional information relating to these issues, see RISK FACTORS in Item 1A and MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL of Alabama Power in Item 7 of the Form 10-K.

Environmental Matters

Compliance costs related to federal and state environmental statutes and regulations could affect earnings if such costs cannot continue to be fully recovered in rates on a timely basis. Environmental compliance spending over the next several years may differ materially from the amounts estimated. The timing, specific requirements, and estimated costs could change as environmental statutes and regulations are adopted or modified. Further, higher costs that are recovered through regulated rates could contribute to reduced demand for electricity, which could negatively affect results of operations, cash flows, and financial condition. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters" of Alabama Power in Item 7 and Note 3 to the financial statements of Alabama Power under "Environmental Matters" in Item 8 of the Form 10-K for additional information.

Environmental Statutes and Regulations

Air Quality

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations – Air Quality" of Alabama Power in Item 7 of the Form 10-K for additional information regarding Alabama's State Implementation Plan requirements related to opacity and the EPA's MATS rule.

On March 6, 2013, the U.S. Court of Appeals for the Eleventh Circuit upheld the EPA's 2008 approval of Alabama's opacity requirements and vacated the EPA's 2011 attempt to rescind its approval, thereby resolving Alabama Power's appeal in Alabama Power's favor. The ultimate outcome of this matter will depend on the outcome of any further appellate or regulatory actions and cannot be determined at this time.

On April 24, 2013, the EPA published a final reconsideration rule addressing new source standards within the MATS rule. Although the EPA had considered revisions to the startup and shutdown provisions of the MATS rule, a final decision on these provisions was deferred. The ultimate impact of this rulemaking will depend on the outcome of any additional rulemaking and/or legal challenges and, therefore, cannot be determined at this time.

Water Quality

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations – Water Quality" of Alabama Power in Item 7 of the Form 10-K for additional information regarding the EPA's proposed revision of the current steam electric effluent guidelines. On April 19, 2013, the EPA signed a proposed rule which requests comments on a range of potential regulatory options for addressing certain wastestreams from steam electric power plants. These regulations could result in the installation of additional controls at certain of Alabama Power's facilities, which could result in significant capital expenditures and compliance costs that could affect future unit retirement and replacement decisions. The ultimate

impact of these proposed regulations will, however, depend on the specific requirements of the final rule and the outcome of any legal challenges and cannot be determined at this time.

FERC Matters

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "FERC Matters" of Alabama Power in Item 7 of the Form 10-K for additional information on Alabama Power's Warrior River hydroelectric license.

On March 18, 2013, the Smith Lake Improvement and Stakeholders' Association filed an appeal to the U.S. Court of Appeals for the District of Columbia Circuit regarding the FERC's orders related to the Warrior River relicensing proceedings. The ultimate outcome of this matter cannot be determined at this time.

PSC Matters

Rate RSE

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "PSC Matters – Rate RSE" of Alabama Power in Item 7 and Note 3 to the financial statements of Alabama Power under "Retail Regulatory Matters – Rate RSE" in Note 8 of the Form 10-K for additional information on Alabama Power's Rate Stabilization and Equalization (Rate RSE). On March 19, 2013, the Alabama PSC issued a notice that the Alabama PSC will hold public proceedings regarding the operation and utilization of Rate RSE. The ultimate outcome of these proceedings cannot be determined at this time.

Rate CNP

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "PSC Matters – Retail Rate Adjustments – Rate CNP" of Alabama Power in Item 7 and Note 3 to the financial statements of Alabama Power under "Retail Regulatory Matters – Rate CNP" in Item 8 of the Form 10-K for additional information regarding Alabama Power's recovery of retail costs through Rate Certificated New Plant Power Purchase Agreement (Rate CNP PPA) and Rate Certificated New Plant Environmental (Rate CNP Environmental). Alabama Power's under recovered Rate CNP PPA balance at March 31, 2013 was $7 million as compared to $9 million at December 31, 2012. This under recovered balance at March 31, 2013 is included in deferred under recovered regulatory clause revenues on Alabama Power's Condensed Balance Sheet herein. For Rate CNP PPA, this classification is based on an estimate, which includes such factors as purchased power capacity and energy demand. A change in any of these factors could have a material impact on the timing of any recovery of the under recovered retail costs. Alabama Power's under recovered Rate CNP Environmental balance at March 31, 2013 was $19 million as compared to $21 million at December 31, 2012. This under recovered balance at March 31, 2013 consists of $11 million in under recovered regulatory clause revenues and $8 million in deferred under recovered regulatory clause revenues on Alabama Power's Condensed Balance Sheet herein. For Rate CNP Environmental, this classification is based on an estimate, which includes such factors as costs to comply with environmental mandates and energy demand. A change in any of these factors could have a material impact on the timing of any recovery of the under recovered retail costs.

Retail Energy Cost Recovery

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "PSC Matters – Energy Cost Recovery" of Alabama Power in Item 7 and Note 3 to the financial statements of Alabama Power under "Retail Regulatory Matters – Energy Cost Recovery" in Item 8 of the Form 10-K for information regarding Alabama Power's energy cost recovery. Alabama Power's over recovered fuel costs at March 31, 2013 totaled $21 million as compared to an under recovered balance of $4 million at December 31, 2012. The over recovered fuel costs at March 31, 2013 are included in other regulatory liabilities, current and the under recovered fuel costs at December 31, 2012 are included in deferred under recovered regulatory clause revenues on Alabama Power's Condensed Balance Sheet herein. These classifications are based on estimates, which include such factors as

weather, generation availability, energy demand, and the price of energy. A change in any of these factors could have a material impact on the timing of any return of the over recovered fuel costs.

Natural Disaster Cost Recovery

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "PSC Matters – Natural Disaster Reserve" of Alabama Power in Item 7 and Note 3 to the financial statements of Alabama Power under "Retail Regulatory Matters – Natural Disaster Reserve" in Item 8 of the Form 10-K for additional information regarding natural disaster cost recovery. At March 31, 2013, the NDR had an accumulated balance of $93 million as compared to $103 million at December 31, 2012, which is included on Alabama Power's Condensed Balance Sheet herein under other regulatory liabilities, deferred. The decrease in the NDR in the first quarter 2013 is a result of storm activity. The related accruals are reflected as operations and maintenance expenses on Alabama Power's Condensed Statement of Income herein.

Other Matters

Alabama Power is involved in various other matters being litigated and regulatory matters that could affect future earnings. In addition, Alabama Power is subject to certain claims and legal actions arising in the ordinary course of business. Alabama Power's business activities are subject to extensive governmental regulation related to public health and the environment, such as regulation of air emissions and water discharges. Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements, such as air quality and water standards, has increased generally throughout the U.S. In particular, personal injury, property damage, and other claims for damages alleged to have been caused by carbon dioxide and other emissions, coal combustion byproducts, and alleged exposure to hazardous materials, and/or requests for injunctive relief in connection with such matters, have become more frequent.

The ultimate outcome of such pending or potential litigation against Alabama Power cannot be predicted at this time; however, for current proceedings not specifically reported in Note (B) to the Condensed Financial Statements herein or in Note 3 to the financial statements of Alabama Power in Item 8 of the Form 10-K, management does not anticipate that the ultimate liabilities, if any, arising from such current proceedings would have a material effect on Alabama Power's financial statements.

See the Notes to the Condensed Financial Statements herein for a discussion of various other contingencies, regulatory matters, and other matters being litigated which may affect future earnings potential.

ACCOUNTING POLICIES

Application of Critical Accounting Policies and Estimates

Alabama Power prepares its financial statements in accordance with GAAP. Significant accounting policies are described in Note 1 to the financial statements of Alabama Power in Item 8 of the Form 10-K. In the application of these policies, certain estimates are made that may have a material impact on Alabama Power's results of operations and related disclosures. Different assumptions and measurements could produce estimates that are significantly different from those recorded in the financial statements. See MANAGEMENT'S DISCUSSION AND ANALYSIS – ACCOUNTING POLICIES – "Application of Critical Accounting Policies and Estimates" of Alabama Power in Item 7 of the Form 10-K for a complete discussion of Alabama Power's critical accounting policies and estimates related to Electric Utility Regulation, Contingent Obligations, and Pension and Other Postretirement Benefits.

FINANCIAL CONDITION AND LIQUIDITY

Overview

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FINANCIAL CONDITION AND LIQUIDITY – "Overview" of Alabama Power in Item 7 of the Form 10-K for additional information. Alabama Power's financial condition remained stable at March 31, 2013. Alabama Power intends to continue to monitor its access to short-term and long-term capital markets as well as its bank credit arrangements to meet future capital and liquidity needs. See "Sources of Capital," "Financing Activities," and "Capital Requirements and Contractual Obligations" herein for additional information.

Net cash provided from operating activities totaled $270 million for the first three months of 2013, an increase of $130 million as compared to the first three months of 2012. The increase in net cash provided from operating activities was primarily due to a decrease in fossil fuel stock, an increase in accounts payable as compared to the first three months of 2012, and the timing of income tax payments and refunds. This was partially offset by an increase in receivables. Net cash used for investing activities totaled $247 million for the first three months of 2013 primarily due to gross property additions related to steam generation, transmission, and distribution equipment. Net cash used for financing activities totaled $95 million for the first three months of 2013 primarily due to the payment of common stock dividends, partially offset by an increase in notes payable. Fluctuations in cash flow from financing activities vary year to year based on capital needs and the maturity or redemption of securities.

Significant balance sheet changes for the first three months of 2013 include increases of $145 million in property, plant, and equipment associated with routine property additions and $68 million in accrued income taxes and decreases of $114 million in other accounts payable and $72 million in cash and cash equivalents.

Capital Requirements and Contractual Obligations

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" of Alabama Power in Item 7 of the Form 10-K for a description of Alabama Power's capital requirements for its construction program, including estimated capital expenditures to comply with existing environmental statutes and regulations, scheduled maturities of long-term debt, as well as the related interest, derivative obligations, preferred and preference stock dividends, leases, purchase commitments, trust funding requirements, and unrecognized tax benefits. See FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations" herein for additional information. Approximately $250 million will be required through March 31, 2014 to fund maturities of long-term debt.

The construction program is subject to periodic review and revision, and actual construction costs may vary from these estimates because of numerous factors. These factors include: changes in business conditions; changes in load projections; changes in environmental statutes and regulations; the outcome of any legal challenges to the environmental rules; changes in generating plants, including unit retirements and replacements and adding or changing fuel sources at existing units, to meet regulatory requirements; changes in the expected environmental compliance program; changes in FERC rules and regulations; Alabama PSC approvals; changes in legislation; the cost and efficiency of construction labor, equipment, and materials; project scope and design changes; storm impacts; and the cost of capital. In addition, there can be no assurance that costs related to capital expenditures will be fully recovered.

Sources of Capital

Alabama Power plans to obtain the funds required for construction and other purposes from sources similar to those used in the past. Alabama Power has primarily utilized funds from operating cash flows, short-term debt, security issuances, and equity contributions from Southern Company. However, the amount, type, and timing of any future financings, if needed, will depend upon regulatory approval, prevailing market conditions, and other factors. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FINANCIAL CONDITION AND LIQUIDITY – "Sources of Capital" of Alabama Power in Item 7 of the Form 10-K for additional information.

Alabama Power's current liabilities sometimes exceed current assets because of Alabama Power's debt due within one year and the periodic use of short-term debt as a funding source primarily to meet scheduled maturities of long-term debt, as well as cash needs, which can fluctuate significantly due to the seasonality of the business.

At March 31, 2013, Alabama Power had approximately $65 million of cash and cash equivalents. Committed credit arrangements with banks at March 31, 2013 were as follows:

Expires[a]					Executable Term Loans		Due Within One Year	
2013	2014	2018	Total	Unused	One Year	Two Years	Term Out	No Term Out
(in millions)			*(in millions)*		*(in millions)*		*(in millions)*	
$ 156	$ 151	$ 1,000	$ 1,307	$ 1,307	$ 56	$ —	$ 56	$ 102

(a) No credit arrangements expire in 2015, 2016, or 2017.

See Note 6 to the financial statements of Alabama Power under "Bank Credit Arrangements" in Item 8 of the Form 10-K and Note (E) to the Condensed Financial Statements under "Bank Credit Arrangements" herein for additional information.

These credit arrangements provide liquidity support to Alabama Power's commercial paper borrowings and variable rate pollution control revenue bonds. The amount of variable rate pollution control revenue bonds outstanding requiring liquidity support as of March 31, 2013 was approximately $793 million. In addition, Alabama Power has substantial cash flow from operating activities and access to capital markets, including a commercial paper program, to meet liquidity needs.

In February 2013, Alabama Power amended an $800 million multi-year credit arrangement, which extended the maturity date from 2016 to 2018. In addition, in March 2013, Alabama Power amended a $200 million credit arrangement, which extended the maturity date from 2014 to 2018.

Alabama Power may meet short-term cash needs through its commercial paper program. Alabama Power may also meet short-term cash needs through a Southern Company subsidiary organized to issue and sell commercial paper at the request and for the benefit of Alabama Power and the other traditional operating companies. Proceeds from such issuances for the benefit of Alabama Power are loaned directly to Alabama Power. The obligations of each company under these arrangements are several and there is no cross affiliate credit support.

Most of these arrangements contain covenants that limit debt levels and contain cross default provisions that are restricted only to the indebtedness (including guarantee obligations) of Alabama Power. Alabama Power is currently in compliance with all such covenants. Alabama Power expects to renew its credit arrangements, as needed, prior to expiration.

Details of short-term borrowings were as follows:

	Short-term Debt at March 31, 2013		Short-term Debt During the Period[a]		
	Amount Outstanding	Weighted Average Interest Rate	Average Outstanding	Weighted Average Interest Rate	Maximum Amount Outstanding
	(in millions)		*(in millions)*		*(in millions)*
Commercial paper	$45	0.2%	$18	0.2%	$85

(a) Average and maximum amounts are based upon daily balances during the three-month period ended March 31, 2013.

Management believes that the need for working capital can be adequately met by utilizing commercial paper programs, lines of credit, and cash.

Credit Rating Risk

Alabama Power does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. There are certain contracts that could require collateral, but not accelerated payment, in the event of a credit rating change to below BBB- and/or Baa3. These contracts are primarily for physical electricity purchases, fuel purchases, fuel transportation and storage, and energy price risk management. At March 31, 2013, the maximum potential collateral requirements under these contracts at a rating below BBB- and/or Baa3 were approximately $268 million. Included in these amounts are certain agreements that could require collateral in the event that one or more Power Pool participant has a credit rating change to below investment grade. Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. Additionally, any credit rating downgrade could impact Alabama Power's ability to access capital markets, particularly the short-term debt market.

Market Price Risk

Alabama Power's market risk exposure relative to interest rate changes for the first quarter 2013 has not changed materially compared to the December 31, 2012 reporting period. Since a significant portion of outstanding indebtedness is at fixed rates, Alabama Power is not aware of any facts or circumstances that would significantly affect exposures on existing indebtedness in the near term. However, the impact on future financing costs cannot now be determined.

Due to cost-based rate regulation and other various cost recovery mechanisms, Alabama Power continues to have limited exposure to market volatility in interest rates, commodity fuel prices, and prices of electricity. To mitigate residual risks relative to movements in electricity prices, Alabama Power enters into physical fixed-price contracts for the purchase and sale of electricity through the wholesale electricity market and, to a lesser extent, financial hedge contracts for natural gas purchases. Alabama Power continues to manage a retail fuel-hedging program implemented per the guidelines of the Alabama PSC. As a result, Alabama Power had no material change in market risk exposure for the first quarter 2013 when compared with the December 31, 2012 reporting period.

The changes in fair value of energy-related derivative contracts, substantially all of which are composed of regulatory hedges, for the three months ended March 31, 2013 were as follows:

	First Quarter 2013 Changes
	Fair Value
	(in millions)
Contracts outstanding at the beginning of the period, assets (liabilities), net	$ (13)
Contracts realized or settled	6
Current period changes[(a)]	12
Contracts outstanding at the end of the period, assets (liabilities), net	$ 5

(a) Current period changes also include the changes in fair value of new contracts entered into during the period, if any.

The changes in the fair value positions of the energy-related derivative contracts, which are substantially all attributable to both the volume and the price of natural gas, for the three months ended March 31, 2013 were as follows:

	First Quarter 2013 Changes
	Fair Value
	(in millions)
Natural gas swaps	$ 15
Natural gas options	3
Total changes	$ 18

The net hedge volumes of energy-related derivative contracts were as follows:

	March 31, 2013	December 31, 2012
	mmBtu Volume	
	(in millions)	
Commodity – Natural gas swaps	**47**	45
Commodity – Natural gas options	**10**	12
Total hedge volume	**57**	57

The weighted average swap contract cost below market prices was approximately $0.04 per mmBtu as of March 31, 2013. The weighted average swap contract cost above market prices was approximately $0.30 per mmBtu as of December 31, 2012. The change in option fair value is primarily attributable to the volatility of the market and the underlying change in the natural gas price. The majority of the natural gas hedge gains and losses are recovered through Alabama Power's retail fuel cost recovery clause.

Regulatory hedges relate to Alabama Power's fuel hedging program where gains and losses are initially recorded as regulatory liabilities and assets, respectively, and then are included in fuel expense as they are recovered through Alabama Power's energy recovery clause.

Unrealized pre-tax gains and losses recognized in income for the three months ended March 31, 2013 and 2012 for energy-related derivative contracts that are not hedges were not material.

Alabama Power uses over-the-counter contracts that are not exchange traded but are fair valued using prices which are market observable, and thus fall into Level 2. See Note (C) to the Condensed Financial Statements herein for further discussion on fair value measurements. The maturities of the energy-related derivative contracts, which are all Level 2 of the fair value hierarchy, at March 31, 2013 were as follows:

	March 31, 2013 Fair Value Measurements			
	Total Fair Value	Maturity		
		Year 1	Years 2&3	Years 4&5
		(in millions)		
Level 1	$ —	$ —	$ —	$ —
Level 2	5	2	3	—
Level 3	—	—	—	—
Fair value of contracts outstanding at end of period	$ 5	$ 2	$ 3	$ —

For additional information, see MANAGEMENT'S DISCUSSION AND ANALYSIS – FINANCIAL CONDITION AND LIQUIDITY – "Market Price Risk" of Alabama Power in Item 7 and Note 1 under "Financial Instruments" and Note 11 to the financial statements of Alabama Power in Item 8 of the Form 10-K and Note (H) to the Condensed Financial Statements herein.

Financing Activities

Alabama Power did not issue or redeem any securities during the three months ended March 31, 2013.

In addition to any financings that may be necessary to meet capital requirements and contractual obligations, Alabama Power plans to continue, when economically feasible, a program to retire higher-cost securities and replace these obligations with lower-cost capital if market conditions permit.

GEORGIA POWER COMPANY

GEORGIA POWER COMPANY
CONDENSED STATEMENTS OF INCOME (UNAUDITED)

	For the Three Months Ended March 31,	
	2013	2012
	(in millions)	
Operating Revenues:		
Retail revenues	**$ 1,729**	$ 1,594
Wholesale revenues, non-affiliates	**62**	66
Wholesale revenues, affiliates	**6**	3
Other revenues	**85**	82
Total operating revenues	**1,882**	1,745
Operating Expenses:		
Fuel	**519**	440
Purchased power, non-affiliates	**50**	93
Purchased power, affiliates	**175**	159
Other operations and maintenance	**431**	434
Depreciation and amortization	**200**	188
Taxes other than income taxes	**95**	87
Total operating expenses	**1,470**	1,401
Operating Income	**412**	344
Other Income and (Expense):		
Allowance for equity funds used during construction	**6**	13
Interest expense, net of amounts capitalized	**(91)**	(91)
Other income (expense), net	**(2)**	(3)
Total other income and (expense)	**(87)**	(81)
Earnings Before Income Taxes	**325**	263
Income taxes	**124**	92
Net Income	**201**	171
Dividends on Preferred and Preference Stock	**4**	4
Net Income After Dividends on Preferred and Preference Stock	**$ 197**	$ 167

CONDENSED STATEMENTS OF COMPREHENSIVE INCOME (UNAUDITED)

	For the Three Months Ended March 31,	
	2013	2012
	(in millions)	
Net Income	**$ 201**	$ 171
Other comprehensive income (loss):		
Qualifying hedges:		
Reclassification adjustment for amounts included in net income, net of tax of $- and $-, respectively	**1**	1
Total other comprehensive income (loss)	**1**	1
Comprehensive Income	**$ 202**	$ 172

The accompanying notes as they relate to Georgia Power are an integral part of these condensed financial statements.

GEORGIA POWER COMPANY
CONDENSED STATEMENTS OF CASH FLOWS (UNAUDITED)

	For the Three Months	
	2013	2012
	(in millions)	
Operating Activities:		
Net income	**$ 201**	$ 171
Adjustments to reconcile net income to net cash provided from operating activities —		
Depreciation and amortization, total	**239**	229
Deferred income taxes	**59**	38
Allowance for equity funds used during construction	**(6)**	(13)
Retail fuel cost over recovery—long-term	**(58)**	—
Deferred expenses	**31**	23
Other, net	**(27)**	10
Changes in certain current assets and liabilities —		
-Receivables	**40**	258
-Fossil fuel stock	**(4)**	(122)
-Prepaid income taxes	**11**	10
-Other current assets	**42**	(4)
-Accounts payable	**78**	(62)
-Accrued taxes	**(127)**	(206)
-Accrued compensation	**(66)**	(80)
-Retail fuel cost over recovery—short-term	**10**	22
-Other current liabilities	**5**	38
Net cash provided from operating activities	**428**	312
Investing Activities:		
Property additions	**(419)**	(476)
Investment in restricted cash from pollution control bonds	**(18)**	—
Nuclear decommissioning trust fund purchases	**(205)**	(287)
Nuclear decommissioning trust fund sales	**204**	285
Cost of removal, net of salvage	**(17)**	(15)
Change in construction payables, net of joint owner portion	**(25)**	(203)
Other investing activities	**1**	15
Net cash used for investing activities	**(479)**	(681)
Financing Activities:		
Increase in notes payable, net	**300**	99
Proceeds —		
Capital contributions from parent company	**11**	9
Pollution control revenue bonds issuances	**18**	—
Senior notes issuances	**650**	750
Redemptions —		
Senior notes	**(650)**	—
Other long-term debt	**—**	(250)
Payment of preferred and preference stock dividends	**(4)**	(4)
Payment of common stock dividends	**(227)**	(227)
Other financing activities	**(13)**	(8)
Net cash provided from financing activities	**85**	369
Net Change in Cash and Cash Equivalents	**34**	—
Cash and Cash Equivalents at Beginning of Period	**45**	13
Cash and Cash Equivalents at End of Period	**$ 79**	$ 13
Supplemental Cash Flow Information:		
Cash paid (received) during the period for —		
Interest (net of $3 and $6 capitalized for 2013 and 2012, respectively)	**$ 72**	$ 58
Income taxes, net	**3**	28
Noncash transactions—accrued property additions at end of period	**212**	178

The accompanying notes as they relate to Georgia Power are an integral part of these condensed financial statements.

GEORGIA POWER COMPANY
CONDENSED BALANCE SHEETS (UNAUDITED)

Assets	At March 31, 2013	At December 31, 2012
	(in millions)	
Current Assets:		
Cash and cash equivalents	**$ 79**	$ 45
Restricted cash and cash equivalents	**18**	—
Receivables —		
Customer accounts receivable	**500**	484
Unbilled revenues	**187**	217
Joint owner accounts receivable	**52**	51
Other accounts and notes receivable	**53**	68
Affiliated companies	**25**	23
Accumulated provision for uncollectible accounts	**(6)**	(6)
Fossil fuel stock, at average cost	**996**	992
Materials and supplies, at average cost	**409**	452
Vacation pay	**86**	85
Prepaid income taxes	**151**	164
Other regulatory assets, current	**48**	72
Other current assets	**48**	104
Total current assets	**2,646**	2,751
Property, Plant, and Equipment:		
In service	**29,462**	29,244
Less accumulated provision for depreciation	**10,574**	10,431
Plant in service, net of depreciation	**18,888**	18,813
Other utility plant, net	**266**	263
Nuclear fuel, at amortized cost	**506**	497
Construction work in progress	**3,079**	2,893
Total property, plant, and equipment	**22,739**	22,466
Other Property and Investments:		
Equity investments in unconsolidated subsidiaries	**46**	45
Nuclear decommissioning trusts, at fair value	**723**	698
Miscellaneous property and investments	**42**	44
Total other property and investments	**811**	787
Deferred Charges and Other Assets:		
Deferred charges related to income taxes	**726**	733
Other regulatory assets, deferred	**1,794**	1,798
Other deferred charges and assets	**279**	268
Total deferred charges and other assets	**2,799**	2,799
Total Assets	**$ 28,995**	$ 28,803

The accompanying notes as they relate to Georgia Power are an integral part of these condensed financial statements.

GEORGIA POWER COMPANY
CONDENSED BALANCE SHEETS (UNAUDITED)

Liabilities and Stockholder's Equity	**At March 31, 2013**	At December 31, 2012
	(in millions)	
Current Liabilities:		
Securities due within one year	**$ 1,047**	$ 1,680
Notes payable	**302**	2
Accounts payable —		
Affiliated	**419**	417
Other	**503**	436
Customer deposits	**241**	237
Accrued taxes —		
Accrued income taxes	**43**	6
Other accrued taxes	**96**	260
Accrued interest	**113**	100
Accrued vacation pay	**60**	61
Accrued compensation	**48**	113
Liabilities from risk management activities	**17**	30
Other regulatory liabilities, current	**56**	73
Over recovered regulatory clause revenues, current	**117**	107
Other current liabilities	**119**	146
Total current liabilities	**3,181**	3,668
Long-term Debt	**8,641**	7,994
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	**4,914**	4,861
Deferred credits related to income taxes	**113**	115
Accumulated deferred investment tax credits	**206**	208
Employee benefit obligations	**945**	950
Asset retirement obligations	**1,148**	1,097
Other cost of removal obligations	**63**	63
Other deferred credits and liabilities	**260**	308
Total deferred credits and other liabilities	**7,649**	7,602
Total Liabilities	**19,471**	19,264
Preferred Stock	**45**	45
Preference Stock	**221**	221
Common Stockholder's Equity:		
Common stock, without par value —		
Authorized — 20,000,000 shares		
Outstanding — 9,261,500 shares	**398**	398
Paid-in capital	**5,599**	5,585
Retained earnings	**3,267**	3,297
Accumulated other comprehensive loss	**(6)**	(7)
Total common stockholder's equity	**9,258**	9,273
Total Liabilities and Stockholder's Equity	**$ 28,995**	$ 28,803

The accompanying notes as they relate to Georgia Power are an integral part of these condensed financial statements.

FIRST QUARTER 2013 vs. FIRST QUARTER 2012

OVERVIEW

Georgia Power operates as a vertically integrated utility providing electricity to retail customers within its traditional service area located within the State of Georgia and to wholesale customers in the Southeast. Many factors affect the opportunities, challenges, and risks of Georgia Power's business of selling electricity. These factors include the ability to maintain a constructive regulatory environment, to maintain and grow energy sales given economic conditions, and to effectively manage and secure timely recovery of costs. These costs include those related to projected long-term demand growth, increasingly stringent environmental standards, reliability, and fuel. In addition, Georgia Power is currently constructing Plant Vogtle Units 3 and 4 to increase its generation diversity. Appropriately balancing required costs and capital expenditures with customer prices will continue to challenge Georgia Power for the foreseeable future. Georgia Power is scheduled to file its next base rate case by July 1, 2013, which will determine whether the 2010 ARP should be continued, modified, or discontinued.

Georgia Power continues to focus on several key performance indicators. These indicators include customer satisfaction, plant availability, system reliability, and net income after dividends on preferred and preference stock. For additional information on these indicators, see MANAGEMENT'S DISCUSSION AND ANALYSIS – OVERVIEW – "Key Performance Indicators" of Georgia Power in Item 7 of the Form 10-K. See FUTURE EARNINGS POTENTIAL – "Other Matters" herein for information regarding an explosion at Plant Bowen in April 2013 that is expected to negatively impact Georgia Power's actual performance on its peak season equivalent forced outage rate, one of its key performance indicators, for 2013, as compared to the target.

RESULTS OF OPERATIONS

Net Income

First Quarter 2013 vs. First Quarter 2012	
(change in millions)	*(% change)*
$30	18.0

Georgia Power's net income after dividends on preferred and preference stock for the first quarter 2013 was $197 million compared to $167 million for the corresponding period in 2012. The increase was primarily due to an increase in retail base revenues as authorized under the 2010 ARP and the NCCR tariff and more favorable weather in the first quarter 2013 as compared to the corresponding period in 2012, partially offset by higher income taxes and an increase in depreciation related to new generating units at Plant McDonough-Atkinson.

Retail Revenues

First Quarter 2013 vs. First Quarter 2012	
(change in millions)	*(% change)*
$135	8.5

In the first quarter 2013, retail revenues were $1.73 billion compared to $1.59 billion for the corresponding period in 2012.

Details of the change to retail revenues were as follows:

	First Quarter 2013	
	(in millions)	*(% change)*
Retail – prior year	$ 1,594	
Estimated change in –		
Rates and pricing	45	2.8
Sales growth (decline)	2	0.1
Weather	20	1.3
Fuel cost recovery	68	4.3
Retail – current year	$ 1,729	8.5%

Revenues associated with changes in rates and pricing increased in the first quarter 2013 when compared to the corresponding period in 2012 primarily due to base tariff increases effective April 2012 and January 1, 2013, as approved by the Georgia PSC, related to placing new generating units at Plant McDonough-Atkinson in service, the financing costs related to the construction of Plant Vogtle Units 3 and 4, and demand-side management costs, partially offset by the pricing effect of increased customer demand.

Revenues attributable to changes in sales increased slightly in the first quarter 2013 when compared to the corresponding period in 2012. Weather-adjusted residential KWH sales increased 0.7%, weather-adjusted commercial KWH sales increased 1.0%, and weather-adjusted industrial KWH sales decreased 3.0% in the first quarter 2013 when compared to the corresponding period in 2012. Decreased demand in the chemicals, paper, and primary metals sectors was the main contributor to the decreases in weather-adjusted industrial KWH sales. In addition, an extra day of sales as a result of the leap year in 2012 negatively impacted KWH sales in all customer classes in 2013.

In the first quarter 2012, Georgia Power began using new actual advanced meter data to compute unbilled revenues. The weather-adjusted KWH sales variances shown above reflect an adjustment to the estimated allocation of Georgia Power's unbilled January 2012 KWH sales among customer classes that is consistent with the actual allocation in 2013. Without this adjustment, first quarter 2013 residential and industrial weather-adjusted KWH sales decreased 1.3% and 3.1%, respectively, as compared to the corresponding period in 2012 and commercial weather-adjusted KWH sales increased 2.8% as compared to the corresponding period in 2012.

Revenues resulting from changes in weather increased in the first quarter 2013 when compared to the corresponding period in 2012 due to more favorable weather in the first quarter 2013 as compared to the corresponding period in 2012.

Fuel revenues and costs are allocated between retail and wholesale jurisdictions. Retail fuel cost recovery revenues increased $68 million in the first quarter 2013 when compared to the corresponding period in 2012 due to increased KWH energy sales and higher fuel costs.

Electric rates include provisions to adjust billings for fluctuations in fuel costs, including the energy component of purchased power costs. Under these fuel cost recovery provisions, fuel revenues generally equal fuel expenses and do not affect net income. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Fuel Cost Recovery" herein for additional information.

Fuel and Purchased Power Expenses

	First Quarter 2013 vs. First Quarter 2012	
	(change in millions)	*(% change)*
Fuel	$ 79	18.0
Purchased power — non-affiliates	(43)	(46.2)
Purchased power — affiliates	16	10.1
Total fuel and purchased power expenses	$ 52	

In the first quarter 2013, total fuel and purchased power expenses were $744 million compared to $692 million in the corresponding period in 2012. The increase was primarily due to a $62 million increase in the average cost of fuel and purchased power due to higher fuel prices and a $65 million increase in the volume of KWHs generated as a result of higher customer demand, partially offset by a $75 million decrease in the volume of KWHs purchased as the market cost of available energy was higher than Georgia Power-owned generation.

Fuel and purchased power energy transactions do not have a significant impact on earnings since these fuel expenses are generally offset by fuel revenues through Georgia Power's fuel cost recovery mechanism. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Fuel Cost Recovery" herein for additional information.

Details of Georgia Power's generation and purchased power were as follows:

	First Quarter 2013	First Quarter 2012
Total generation *(billions of KWHs)*	**15**	13
Total purchased power *(billions of KWHs)*	**6**	8
Sources of generation *(percent)* —		
Coal	**29**	42
Nuclear	**22**	30
Gas	**46**	26
Hydro	**3**	2
Cost of fuel, generated *(cents per net KWH)* —		
Coal	**5.28**	4.67
Nuclear	**0.90**	0.86
Gas	**3.14**	3.16
Average cost of fuel, generated *(cents per net KWH)*	**3.28**	3.10
Average cost of purchased power *(cents per net KWH)*[(a)]	**4.44**	3.86

(a) Average cost of purchased power includes fuel purchased by Georgia Power for tolling agreements where power is generated by the provider.

Fuel

In the first quarter 2013, fuel expense was $519 million compared to $440 million in the corresponding period in 2012. The increase was primarily due to a 16.8% increase in the volume of KWHs generated as a result of higher KWH demand and a 5.8% increase in the average cost of fuel per KWH generated primarily due to higher coal and nuclear fuel prices.

Purchased Power – Non-Affiliates

In the first quarter 2013, purchased power expense from non-affiliates was $50 million compared to $93 million in the corresponding period in 2012. The decrease was due to a 68.3% decrease in the volume of KWHs purchased as the cost of Georgia Power-owned generation was lower than the market cost of available energy, partially offset by an increase of 70.8% in the average cost per KWH purchased primarily due to fixed capacity payment provisions in the PPAs.

Energy purchases from non-affiliates will vary depending on the market prices of wholesale energy as compared to the cost of the Southern Company system's generation, demand for energy within the Southern Company system's service territory, and the availability of the Southern Company system's generation.

Purchased Power – Affiliates

In the first quarter 2013, purchased power expense from affiliates was $175 million compared to $159 million in the corresponding period in 2012. The increase was due to a 16.4% increase in the average cost per KWH purchased, reflecting higher fuel prices, partially offset by a 12.3% decrease in the volume of KWHs purchased as Georgia Power units generally dispatched at a lower cost than other Southern Company system resources.

Energy purchases from affiliates will vary depending on the demand and the availability and cost of generating resources at each company within the Southern Company system. These purchases are made in accordance with the IIC or other contractual agreements, all as approved by the FERC.

Other Operations and Maintenance Expenses

First Quarter 2013 vs. First Quarter 2012	
(change in millions)	*(% change)*
$(3)	(0.7)

In the first quarter 2013, other operations and maintenance expenses were $431 million compared to $434 million in the corresponding period in 2012. The decrease was primarily due to a $10 million decrease in fossil generating maintenance due to timing of plant outages and a $2 million decrease in uncollectible account expense, partially offset by a $10 million increase in pension and other employee benefit-related expenses.

Depreciation and Amortization

First Quarter 2013 vs. First Quarter 2012	
(change in millions)	*(% change)*
$12	6.4

In the first quarter 2013, depreciation and amortization was $200 million compared to $188 million in the corresponding period in 2012. The increase was primarily due to an increase of $23 million in depreciation as a result of additional plant in service primarily due to the completion of Plant McDonough-Atkinson Units 5 and 6 in April 2012 and October 2012, respectively, partially offset by $9 million in amortization of the regulatory liability previously established for state income tax credits, as authorized by the Georgia PSC. See Note 1 to the financial statements of Georgia Power under "Regulatory Assets and Liabilities" in Item 8 of the Form 10-K for additional information.

Taxes Other Than Income Taxes

First Quarter 2013 vs. First Quarter 2012	
(change in millions)	*(% change)*
$8	9.2

In the first quarter 2013, taxes other than income taxes were $95 million compared to $87 million in the corresponding period in 2012. The increase was due to a $4 million increase in property taxes and a $4 million increase in municipal franchise fees related to higher retail revenues in 2013.

Allowance for Equity Funds Used During Construction

First Quarter 2013 vs. First Quarter 2012	
(change in millions)	*(% change)*
$(7)	(53.8)

In the first quarter 2013, AFUDC equity was $6 million compared to $13 million in the corresponding period in 2012. The decrease was primarily due to the completion of Plant McDonough-Atkinson Units 5 and 6 in April 2012 and October 2012, respectively.

Income Taxes

First Quarter 2013 vs. First Quarter 2012	
(change in millions)	*(% change)*
$32	34.8

In the first quarter 2013, income taxes were $124 million compared to $92 million in the corresponding period in 2012. The increase was primarily due to higher pre-tax earnings, the recognition in 2012 of previously unrecognized tax positions as a result of a settlement with the IRS related to the production activities deduction, and a decrease in non-taxable AFUDC equity.

FUTURE EARNINGS POTENTIAL

The results of operations discussed above are not necessarily indicative of Georgia Power's future earnings potential. The level of Georgia Power's future earnings depends on numerous factors that affect the opportunities, challenges, and risks of Georgia Power's business of selling electricity. These factors include Georgia Power's ability to maintain a constructive regulatory environment that continues to allow for the timely recovery of prudently-incurred costs during a time of increasing costs and the successful completion of ongoing construction projects. Future earnings in the near term will depend, in part, upon maintaining energy sales which is subject to a number of factors. These factors include weather, competition, new energy contracts with neighboring utilities, energy conservation practiced by customers, the price of electricity, the price elasticity of demand, and the rate of economic growth or decline in Georgia Power's service territory. Changes in regional and global economic conditions may impact sales for Georgia Power as the pace of the economic recovery remains uncertain. The timing and extent of the economic recovery will impact growth and may impact future earnings. For additional information relating to these issues, see RISK FACTORS in Item 1A and MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL of Georgia Power in Item 7 of the Form 10-K.

Environmental Matters

Compliance costs related to federal and state environmental statutes and regulations could affect earnings if such costs cannot continue to be fully recovered in rates on a timely basis. Environmental compliance spending over the next several years may differ materially from the amounts estimated. The timing, specific requirements, and estimated costs could change as environmental statutes and regulations are adopted or modified. Further, higher costs that are recovered through regulated rates could contribute to reduced demand for electricity, which could

negatively affect results of operations, cash flows, and financial condition. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters" of Georgia Power in Item 7 and Note 3 to the financial statements of Georgia Power under "Environmental Matters" in Item 8 of the Form 10-K for additional information.

Environmental Statutes and Regulations

Air Quality

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations – Air Quality" of Georgia Power in Item 7 of the Form 10-K for information regarding the EPA's MATS rule and the 2007 State of Georgia Multi-Pollutant Rule.

On April 24, 2013, the EPA published a final reconsideration rule addressing new source standards within the MATS rule. Although the EPA had considered revisions to the startup and shutdown provisions of the MATS rule, a final decision on these provisions was deferred. The ultimate impact of this rulemaking will depend on the outcome of any additional rulemaking and/or legal challenges and, therefore, cannot be determined at this time.

On April 30, 2013, the State of Georgia finalized revisions to the 2007 State of Georgia Multi-Pollutant Rule and a companion rule requiring a 95% reduction in sulfur dioxide emissions from certain coal-fired generating units. The revisions modify the compliance dates under those two rules for units yet to be controlled to synchronize them with the MATS rule compliance deadline. The revisions also allow natural gas to be used as a compliance alternative at Plant Yates as contemplated by the 2013 IRP. The ultimate outcome of these matters cannot be determined at this time. See Note 3 to the financial statements of Georgia Power under "Retail Regulatory Matters – Integrated Resource Plans" in Item 8 of the Form 10-K for additional information.

Water Quality

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations – Water Quality" of Georgia Power in Item 7 of the Form 10-K for additional information regarding the EPA's proposed revision of the current steam electric effluent guidelines. On April 19, 2013, the EPA signed a proposed rule which requests comments on a range of potential regulatory options for addressing certain wastestreams from steam electric power plants. These regulations could result in the installation of additional controls at certain of Georgia Power's facilities, which could result in significant capital expenditures and compliance costs that could affect future unit retirement and replacement decisions. The ultimate impact of these proposed regulations will, however, depend on the specific requirements of the final rule and the outcome of any legal challenges and cannot be determined at this time.

PSC Matters

Fuel Cost Recovery

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "PSC Matters – Fuel Cost Recovery" of Georgia Power in Item 7 and Note 3 to the financial statements of Georgia Power under "Retail Regulatory Matters – Fuel Cost Recovery" in Item 8 of the Form 10-K for additional information.

As of March 31, 2013, Georgia Power's fuel cost over recovery balance totaled $182 million and is included in current liabilities and other deferred credits and liabilities on Georgia Power's Condensed Balance Sheet herein.

Fuel cost recovery revenues as recorded on the financial statements are adjusted for differences in actual recoverable fuel costs and amounts billed in current regulated rates. Accordingly, any changes in the billing factor will not have a significant effect on Georgia Power's revenues or net income, but will affect cash flow. See Note (B) to the Condensed Financial Statements under "Retail Regulatory Matters – Georgia Power – Fuel Cost Recovery" herein for additional information.

Integrated Resource Plans

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations – Air Quality," " – Water Quality," and " – Coal Combustion Byproducts" of Georgia Power in Item 7 and Note 3 to the financial statements of Georgia Power under "Retail Regulatory Matters – Rate Plans" and " – Integrated Resource Plans" in Item 8 of the Form 10-K for additional information regarding proposed and final EPA rules and regulations, including the MATS rule for coal- and oil-fired electric utility steam generating units, revisions to effluent guidelines for steam electric power plants, and additional regulation of coal combustion byproducts; the State of Georgia's Multi-Pollutant Rule; Georgia Power's analysis of the potential costs and benefits of installing the required controls on its fossil generating units in light of these regulations; the 2010 ARP; the 2011 IRP; and the 2013 IRP.

On April 17, 2013, the Georgia PSC approved the decertification of Plant Bowen Unit 6 (32 MWs), which was retired on April 25, 2013. The Georgia PSC is scheduled to vote on all other aspects of the 2013 IRP in July 2013. The ultimate outcome of this matter cannot be determined at this time.

Separately, on April 22, 2013, Georgia Power executed two PPAs to purchase energy from two wind farms with capacity totaling 250 MWs in southwest Oklahoma that will commence in 2016 and end in 2035. In addition, on April 29, 2013, Georgia Power executed a PPA for the purchase of 50 MWs of capacity and energy that will commence in 2015 and end in 2035. These PPAs are subject to Georgia PSC approval and, if approved, will result in contractual obligations of approximately $13 million in 2015, $47 million in 2016, $48 million in 2017, and $1.3 billion thereafter.

Nuclear Construction

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "PSC Matters – Nuclear Construction" of Georgia Power in Item 7 and Note 3 to the financial statements of Georgia Power under "Retail Regulatory Matters – Nuclear Construction" in Item 8 of the Form 10-K and Note (B) to the Condensed Financial Statements under "Retail Regulatory Matters – Georgia Power – Nuclear Construction" herein for additional information regarding the construction of Plant Vogtle Units 3 and 4, the eighth Vogtle Construction Monitoring (VCM) report, and pending litigation.

In 2009, the Georgia PSC approved inclusion of the Plant Vogtle Units 3 and 4 related CWIP accounts in rate base, and the State of Georgia enacted the Georgia Nuclear Energy Financing Act, which allows Georgia Power to recover financing costs for nuclear construction projects through annual adjustments to an NCCR tariff by including the related CWIP accounts in rate base during the construction period.

The Georgia PSC approved increases to the NCCR tariff of approximately $223 million, $35 million, and $50 million, effective January 1, 2011, 2012, and 2013, respectively. Through the NCCR tariff, Georgia Power is collecting and amortizing to earnings approximately $91 million of financing costs, capitalized in 2009 and 2010, over the five-year period ending December 31, 2015, in addition to the ongoing financing costs. At March 31, 2013, approximately $50 million of these 2009 and 2010 costs remained unamortized in CWIP.

Georgia Power is required to file semi-annual VCM reports with the Georgia PSC by February 28 and August 31 each year. On February 19, 2013, the Georgia PSC voted to approve Georgia Power's seventh VCM report, including construction capital costs incurred through June 30, 2012 of approximately $2.0 billion. Georgia Power's eighth VCM report requests approval for an additional $0.2 billion of construction capital costs incurred through December 31, 2012. If the projected certified construction capital costs to be borne by Georgia Power increase by 5% or the projected in-service dates are significantly extended, Georgia Power is required to seek an amendment to the Plant Vogtle Units 3 and 4 certificate from the Georgia PSC. Accordingly, the eighth VCM also requests an amendment to the certificate to increase the estimated in-service capital cost of Plant Vogtle Units 3 and 4 to $4.8 billion and to extend the estimated in-service dates to the fourth quarter 2017 and the fourth quarter 2018 for Plant Vogtle Units 3 and 4, respectively. Associated financing costs during the construction period are estimated to total approximately $2.0 billion. The Georgia PSC is expected to vote on the eighth VCM by October 2013.

In addition, processes are in place that are designed to assure compliance with the requirements specified in the Westinghouse Design Control Document, as amended (DCD), and the combined construction and operating licenses (COLs), including rigorous inspections by Southern Nuclear and the NRC that occur throughout construction. During the fourth quarter 2012, certain details of the rebar design for the Plant Vogtle Unit 3 nuclear island were evaluated for consistency with the DCD and deviations were identified. On February 26, 2013 and March 1, 2013, the NRC approved the two license amendment requests required to conform the rebar design details to NRC requirements and, on March 14, 2013, the placement of basemat structural concrete for the nuclear island of Plant Vogtle Unit 3 was completed. Additional license amendment requests are pending before the NRC. Various design and other issues are expected to arise as construction proceeds, which may result in additional license amendments or require other resolution. If any license amendment requests are not resolved in a timely manner, there may be delays in the project schedule that could result in increased costs either to the Owners, the Contractor, or both.

As construction continues, additional delays in the fabrication and assembly of structural modules, the failure of such modules to meet applicable standards, or other issues may further impact project schedule and cost. Additional claims by the Contractor or Georgia Power (on behalf of the Owners) are also likely to arise throughout construction. These claims may be resolved through formal and informal dispute resolution procedures under the engineering, procurement, and construction agreement for Plant Vogtle Units 3 and 4, but also may be resolved through litigation.

See RISK FACTORS of Georgia Power in Item 1A of the Form 10-K for a discussion of certain risks associated with the licensing, construction, and operation of nuclear generating units, including potential impacts that could result from a major incident at a nuclear facility anywhere in the world.

The ultimate outcome of these matters cannot be determined at this time.

Other Matters

Georgia Power is involved in various other matters being litigated and regulatory matters that could affect future earnings. In addition, Georgia Power is subject to certain claims and legal actions arising in the ordinary course of business. Georgia Power's business activities are subject to extensive governmental regulation related to public health and the environment, such as regulation of air emissions and water discharges. Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements, such as air quality and water standards, has increased generally throughout the U.S. In particular, personal injury, property damage, and other claims for damages alleged to have been caused by carbon dioxide and other emissions, coal combustion byproducts, and alleged exposure to hazardous materials, and/or requests for injunctive relief in connection with such matters, have become more frequent.

The ultimate outcome of such pending or potential litigation against Georgia Power cannot be predicted at this time; however, for current proceedings not specifically reported in Note (B) to the Condensed Financial Statements herein or in Note 3 to the financial statements of Georgia Power in Item 8 of the Form 10-K, management does not anticipate that the ultimate liabilities, if any, arising from such current proceedings would have a material effect on Georgia Power's financial statements.

See the Notes to the Condensed Financial Statements herein for a discussion of various other contingencies, regulatory matters, and other matters being litigated which may affect future earnings potential.

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Other Matters" of Georgia Power in Item 7 of the Form 10-K for additional information regarding the NRC's performance of additional operational and safety reviews of nuclear facilities in the U.S. following the major earthquake and tsunami that struck Japan in 2011. On March 19, 2013, the NRC issued an order relating to hardened vents for certain classes of containment structures, including the one in use at Plant Hatch. Georgia Power is continuing to analyze the impact of this order. The ultimate outcome of this matter cannot be determined at this time; however, management does not currently anticipate that the compliance costs associated with this order would have a material impact on Georgia Power's financial statements.

On April 4, 2013, an explosion occurred at Plant Bowen Unit 2 that resulted in substantial damage to the Plant Bowen Unit 2 generator, Plant Bowen's Units 1 and 2 control room and surrounding areas, as well as Plant Bowen's switchyard. The extent of the damage sustained by Plant Bowen Unit 1 is unknown. Plant Bowen Units 1 and 2 (approximately 1,400 MWs) remain offline, pending assessment of the damage and completion of repairs. Georgia Power expects that any material repair costs related to the damage will be covered by property insurance. The ultimate outcome of this matter cannot be determined at this time.

ACCOUNTING POLICIES

Application of Critical Accounting Policies and Estimates

Georgia Power prepares its financial statements in accordance with GAAP. Significant accounting policies are described in Note 1 to the financial statements of Georgia Power in Item 8 of the Form 10-K. In the application of these policies, certain estimates are made that may have a material impact on Georgia Power's results of operations and related disclosures. Different assumptions and measurements could produce estimates that are significantly different from those recorded in the financial statements. See MANAGEMENT'S DISCUSSION AND ANALYSIS – ACCOUNTING POLICIES – "Application of Critical Accounting Policies and Estimates" of Georgia Power in Item 7 of the Form 10-K for a complete discussion of Georgia Power's critical accounting policies and estimates related to Electric Utility Regulation, Contingent Obligations, and Pension and Other Postretirement Benefits.

FINANCIAL CONDITION AND LIQUIDITY

Overview

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FINANCIAL CONDITION AND LIQUIDITY – "Overview" of Georgia Power in Item 7 of the Form 10-K for additional information. Georgia Power's financial condition remained stable at March 31, 2013. Georgia Power intends to continue to monitor its access to short-term and long-term capital markets as well as its bank credit arrangements to meet future capital and liquidity needs. See "Capital Requirements and Contractual Obligations," "Sources of Capital," and "Financing Activities" herein for additional information.

Net cash provided from operating activities totaled $428 million for the first three months of 2013 compared to $312 million for the corresponding period in 2012. The increase was primarily due to lower fuel inventory additions in 2013. Net cash used for investing activities totaled $479 million compared to $681 million used in the corresponding period in 2012. The decrease was primarily due to higher cash payments for construction expenditures in 2012. Net cash provided from financing activities totaled $85 million for the first three months of 2013 compared to $369 million in the corresponding period in 2012. The decrease is primarily due to additional net issuances of debt in 2012. Fluctuations in cash flow from financing activities vary from year to year based on capital needs and the maturity or redemption of securities.

Significant balance sheet changes for the first three months of 2013 include increases of $273 million in total property, plant, and equipment and $314 million in debt, as well as a $164 million decrease in other accrued taxes.

Capital Requirements and Contractual Obligations

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" of Georgia Power in Item 7 of the Form 10-K for a description of Georgia Power's capital requirements for its construction program, including estimated capital expenditures for new generating facilities and to comply with existing environmental statutes and regulations, scheduled maturities of long-term debt, as well as related interest, derivative obligations, preferred and preference stock dividends, leases, purchase commitments, trust funding requirements, and unrecognized tax benefits. See FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations" herein for additional information. Approximately $1.0 billion will be required through March 31, 2014 to fund maturities of long-term debt.

The construction program is subject to periodic review and revision, and actual construction costs may vary from these estimates because of numerous factors. These factors include: changes in business conditions; changes in load projections; changes in environmental statutes and regulations; the outcome of any legal challenges to the environmental rules; changes in generating plants, including unit retirements and replacements and adding or changing fuel sources at existing units, to meet regulatory requirements; changes in FERC rules and regulations; Georgia PSC approvals; changes in the expected environmental compliance program; changes in legislation; the cost and efficiency of construction labor, equipment, and materials; project scope and design changes; storm impacts; and the cost of capital. In addition, there can be no assurance that costs related to capital expenditures will be fully recovered.

Sources of Capital

Except as described below with respect to potential DOE loan guarantees, Georgia Power plans to obtain the funds required for construction and other purposes from sources similar to those used in the past, which were primarily from operating cash flows, short-term debt, security issuances, term loans, and equity contributions from Southern Company. However, the amount, type, and timing of any future financings, if needed, will depend upon regulatory approval, prevailing market conditions, and other factors. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FINANCIAL CONDITION AND LIQUIDITY – "Sources of Capital" of Georgia Power in Item 7 of the Form 10-K for additional information.

In 2010, Georgia Power reached an agreement with the DOE to accept terms for a conditional commitment for federal loan guarantees that would apply to future borrowings by Georgia Power related to the construction of Plant Vogtle Units 3 and 4. Any borrowings guaranteed by the DOE would be full recourse to Georgia Power and secured by a first priority lien on Georgia Power's 45.7% undivided ownership interest in Plant Vogtle Units 3 and 4. Total guaranteed borrowings would not exceed the lesser of 70% of eligible project costs or approximately $3.46 billion and are expected to be funded by the Federal Financing Bank. Final approval and issuance of loan guarantees by the DOE are subject to negotiation of definitive agreements, completion of due diligence by the DOE, receipt of any necessary regulatory approvals, and satisfaction of other conditions. In the event that the DOE does not issue a loan guarantee or Georgia Power determines that the final terms and conditions of the loan guarantee by the DOE are not in the best interest of its customers, Georgia Power expects to finance the construction of Plant Vogtle Units 3 and 4 through traditional capital markets financings. There can be no assurance that the DOE will issue loan guarantees for Georgia Power. The conditional commitment will expire on June 30, 2013, unless further extended by the DOE. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Nuclear Construction" herein for more information on Plant Vogtle Units 3 and 4.

Georgia Power's current liabilities frequently exceed current assets because of the continued use of short-term debt as a funding source to meet scheduled maturities of long-term debt, as well as cash needs, which can fluctuate significantly due to the seasonality of the business. Georgia Power has substantial cash flow from operating activities and access to the capital markets to meet liquidity needs.

At March 31, 2013, Georgia Power had approximately $79 million of cash and cash equivalents. Committed credit arrangements with banks at March 31, 2013 were as follows:

Expires[a]						Executable Term Loans		Due Within One Year	
2013	2014	2016	2018	Total	Unused	One Year	Two Years	Term Out	No Term Out
(in millions)				*(in millions)*		*(in millions)*		*(in millions)*	
$ —	$ —	$ 150	$ 1,600	$ 1,750	$ 1,740	$ —	$ —	$ —	$ —

(a) No credit arrangements expire in 2015 or 2017.

See Note 6 to the financial statements of Georgia Power under "Bank Credit Arrangements" in Item 8 of the Form 10-K and Note (E) to the Condensed Financial Statements under "Bank Credit Arrangements" herein for additional information.

These credit arrangements provide liquidity support to Georgia Power's commercial paper borrowings and variable rate pollution control revenue bonds. The amount of variable rate pollution control revenue bonds outstanding requiring liquidity support as of March 31, 2013 was approximately $874 million.

In February 2013, Georgia Power amended its multi-year credit arrangement, which extended the maturity date from 2016 to 2018. In addition, in March 2013, Georgia Power amended certain of its credit arrangements, which extended the maturity dates from 2014 to 2016.

Georgia Power may also meet short-term cash needs through a Southern Company subsidiary organized to issue and sell commercial paper at the request and for the benefit of Georgia Power and the other traditional operating companies. Proceeds from such issuances for the benefit of Georgia Power are loaned directly to Georgia Power. The obligations of each company under these arrangements are several and there is no cross affiliate credit support.

These arrangements contain covenants that limit debt levels and contain cross default provisions that are restricted only to the indebtedness of Georgia Power. Georgia Power is currently in compliance with all such covenants. Georgia Power expects to renew its credit arrangements, as needed, prior to expiration.

Details of short-term borrowings were as follows:

	Short-term Debt at March 31, 2013[a]		Short-term Debt During the Period[a][b]		
	Amount Outstanding	Weighted Average Interest Rate	Average Outstanding	Weighted Average Interest Rate	Maximum Amount Outstanding
	(in millions)		*(in millions)*		*(in millions)*
Commercial paper	$ —	—%	$ 110	0.3%	$ 296
Short-term bank debt	300	0.9%	87	0.9%	300
Total	$ 300	0.9%	$ 197	0.5%	

(a) Excludes notes payable related to other energy service contracts of $2 million.
(b) Average and maximum amounts are based upon daily balances during the three-month period ended March 31, 2013.

Management believes that the need for working capital can be adequately met by utilizing commercial paper programs, lines of credit, and cash.

Credit Rating Risk

Georgia Power does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. There are certain contracts that could require collateral, but not accelerated payment, in the event of a credit rating change to BBB- and/or Baa3 or below. These contracts are for physical electricity purchases and sales, fuel purchases, fuel transportation and storage, energy price risk management, and construction of new generation. The maximum potential collateral requirements under these contracts at March 31, 2013 were as follows:

Credit Ratings	Maximum Potential Collateral Requirements
	(in millions)
At BBB- and/or Baa3	$ 65
Below BBB- and/or Baa3	1,298

Included in these amounts are certain agreements that could require collateral in the event that one or more Power Pool participant has a credit rating change to below investment grade. Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. Additionally, any credit rating downgrade could impact Georgia Power's ability to access capital markets, particularly the short-term debt market.

Market Price Risk

Georgia Power's market risk exposure relative to interest rate changes for the first quarter 2013 has not changed materially compared with the December 31, 2012 reporting period. Since a significant portion of outstanding indebtedness is at fixed rates, Georgia Power is not aware of any facts or circumstances that would significantly affect exposures on existing indebtedness in the near term. However, the impact on future financing costs cannot now be determined.

Due to cost-based rate regulation and other various cost recovery mechanisms, Georgia Power continues to have limited exposure to market volatility in interest rates, commodity fuel prices, and prices of electricity. To mitigate residual risks relative to movements in electricity prices, Georgia Power enters into physical fixed-price contracts for the purchase and sale of electricity through the wholesale electricity market and, to a lesser extent, financial hedge contracts for natural gas purchases. Georgia Power continues to manage a fuel-hedging program implemented per the guidelines of the Georgia PSC. As a result, Georgia Power had no material change in market risk exposure for the first quarter 2013 relative to fuel and electricity prices when compared with the December 31, 2012 reporting period.

The changes in fair value of energy-related derivative contracts, substantially all of which are composed of regulatory hedges, for the three months ended March 31, 2013 were as follows:

	First Quarter 2013 Changes
	Fair Value
	(in millions)
Contracts outstanding at the beginning of the period, assets (liabilities), net	$ (33)
Contracts realized or settled	10
Current period changes[(a)]	8
Contracts outstanding at the end of the period, assets (liabilities), net	$ (15)

(a) Current period changes also include the changes in fair value of new contracts entered into during the period, if any.

The changes in the fair value positions of the energy-related derivative contracts, which are substantially all attributable to both the volume and the price of natural gas, for the three months ended March 31, 2013 were as follows:

	First Quarter 2013 Changes
	Fair Value
	(in millions)
Natural gas swaps	$ 6
Natural gas options	12
Total changes	$ 18

The net hedge volumes of energy-related derivative contracts were as follows:

	March 31, 2013	December 31, 2012
	mmBtu Volume	
	(in millions)	
Commodity – Natural gas swaps	**11**	12
Commodity – Natural gas options	**79**	93
Total hedge volume	**90**	105

The weighted average swap contract cost above market prices was approximately $0.64 per mmBtu as of March 31, 2013 and $1.09 per mmBtu as of December 31, 2012. The change in option fair value is primarily attributable to the volatility of the market and the underlying change in the natural gas price. All natural gas hedge gains and losses are recovered through Georgia Power's fuel cost recovery mechanism.

Regulatory hedges relate to Georgia Power's fuel-hedging program where gains and losses are initially recorded as regulatory liabilities and assets, respectively, and then are included in fuel expense as they are recovered through Georgia Power's fuel cost recovery mechanism.

Unrealized pre-tax gains and losses recognized in income for the three months ended March 31, 2013 and 2012 for energy-related derivative contracts that are not hedges were not material.

Georgia Power uses over-the-counter contracts that are not exchange traded but are fair valued using prices which are market observable, and thus fall into Level 2. See Note (C) to the Condensed Financial Statements herein for further discussion on fair value measurements. The maturities of the energy-related derivative contracts, which are all Level 2 of the fair value hierarchy, at March 31, 2013 were as follows:

	March 31, 2013 Fair Value Measurements		
	Total	Maturity	
	Fair Value	Year 1	Years 2&3
		(in millions)	
Level 1	$ —	$ —	$ —
Level 2	(15)	(11)	(4)
Level 3	—	—	—
Fair value of contracts outstanding at end of period	$ (15)	$ (11)	$ (4)

For additional information, see MANAGEMENT'S DISCUSSION AND ANALYSIS – FINANCIAL CONDITION AND LIQUIDITY – "Market Price Risk" of Georgia Power in Item 7 and Note 1 under "Financial Instruments" and Note 11 to the financial statements of Georgia Power in Item 8 of the Form 10-K and Note (H) to the Condensed Financial Statements herein.

Financing Activities

In January 2013, Georgia Power's $300 million aggregate principal amount of Series 2011A Floating Rate Senior Notes due January 15, 2013 matured.

In March 2013, Georgia Power entered into three 60-day floating rate bank loans bearing interest based on one-month LIBOR. Each of these short-term loans was for $100 million aggregate principal amount, and the proceeds were used for working capital and other general corporate purposes, including Georgia Power's continuous construction program.

In March 2013, Georgia Power issued $400 million aggregate principal amount of Series 2013A 4.30% Senior Notes due March 15, 2043. Also in March 2013, Georgia Power issued $250 million aggregate principal amount of Series 2013B Floating Rate Senior Notes due March 15, 2016. The proceeds from the sale of the Series 2013A Senior Notes, together with the proceeds from the sale of the Series 2013B Senior Notes, were used to repay at maturity $350 million aggregate principal amount of Georgia Power's Series 2010A Floating Rate Senior Notes due March 15, 2013, to repay a portion of its outstanding short-term indebtedness, and for general corporate purposes, including Georgia Power's continuous construction program.

In March 2013, the Development Authority of Monroe County issued $17.5 million aggregate principal amount of Pollution Control Revenue Bonds (Georgia Power Company Plant Scherer Project), First Series 2013 due April 1, 2043 for the benefit of Georgia Power. The proceeds were used to redeem, in April 2013, $17.5 million aggregate principal amount of Development Authority of Monroe County Pollution Control Revenue Bonds (Georgia Power Company Plant Scherer Project), Second Series 1997.

In addition to any financings that may be necessary to meet capital requirements and contractual obligations, Georgia Power plans to continue, when economically feasible, a program to retire higher-cost securities and replace these obligations with lower-cost capital if market conditions permit.

GULF POWER COMPANY

GULF POWER COMPANY
CONDENSED STATEMENTS OF INCOME (UNAUDITED)

	For the Three Months Ended March 31,	
	2013	2012
	(in thousands)	
Operating Revenues:		
Retail revenues	**$ 259,877**	$ 238,520
Wholesale revenues, non-affiliates	**21,208**	27,118
Wholesale revenues, affiliates	**29,455**	36,364
Other revenues	**15,734**	14,243
Total operating revenues	**326,274**	316,245
Operating Expenses:		
Fuel	**120,846**	121,088
Purchased power, non-affiliates	**11,135**	11,225
Purchased power, affiliates	**3,312**	2,513
Other operations and maintenance	**78,662**	75,230
Depreciation and amortization	**37,053**	33,307
Taxes other than income taxes	**23,626**	23,784
Total operating expenses	**274,634**	267,147
Operating Income	**51,640**	49,098
Other Income and (Expense):		
Allowance for equity funds used during construction	**1,134**	1,237
Interest expense, net of amounts capitalized	**(14,369)**	(15,368)
Other income (expense), net	**(976)**	(1,009)
Total other income and (expense)	**(14,211)**	(15,140)
Earnings Before Income Taxes	**37,429**	33,958
Income taxes	**14,086**	11,741
Net Income	**23,343**	22,217
Dividends on Preference Stock	**1,551**	1,551
Net Income After Dividends on Preference Stock	**$ 21,792**	$ 20,666

CONDENSED STATEMENTS OF COMPREHENSIVE INCOME (UNAUDITED)

	For the Three Months Ended March 31,	
	2013	2012
	(in thousands)	
Net Income	**$ 23,343**	$ 22,217
Other comprehensive income (loss):		
Qualifying hedges:		
Reclassification adjustment for amounts included in net income, net of tax of $90 and $90, respectively	**143**	143
Total other comprehensive income (loss)	**143**	143
Comprehensive Income	**$ 23,486**	$ 22,360

The accompanying notes as they relate to Gulf Power are an integral part of these condensed financial statements.

GULF POWER COMPANY
CONDENSED STATEMENTS OF CASH FLOWS (UNAUDITED)

	For the Three Months Ended March 31,	
	2013	2012
	(in thousands)	
Operating Activities:		
Net income	**$ 23,343**	$ 22,217
Adjustments to reconcile net income to net cash provided from operating activities —		
Depreciation and amortization, total	**38,794**	34,844
Deferred income taxes	**16,777**	32,505
Allowance for equity funds used during construction	**(1,134)**	(1,237)
Pension, postretirement, and other employee benefits	**2,889**	1,315
Stock based compensation expense	**669**	685
Other, net	**2,485**	5,478
Changes in certain current assets and liabilities —		
-Receivables	**(2,305)**	14,754
-Prepayments	**934**	1,559
-Fossil fuel stock	**1,423**	1,543
-Materials and supplies	**(513)**	(1,476)
-Prepaid income taxes	**(7,667)**	17,324
-Accounts payable	**(17,812)**	(21,516)
-Accrued taxes	**5,380**	(1,453)
-Accrued compensation	**(9,451)**	(9,190)
-Over recovered regulatory clause revenues	**(10,186)**	14,516
-Other current liabilities	**6,073**	5,637
Net cash provided from operating activities	**49,699**	117,505
Investing Activities:		
Property additions	**(66,696)**	(94,879)
Cost of removal, net of salvage	**(3,469)**	(9,342)
Change in construction payables	**1,787**	7,773
Payments pursuant to long-term service agreements	**(1,558)**	(2,274)
Other investing activities	**243**	(76)
Net cash used for investing activities	**(69,693)**	(98,798)
Financing Activities:		
Increase (decrease) in notes payable, net	**5,809**	(27,338)
Proceeds —		
Common stock issued to parent	**40,000**	40,000
Capital contributions from parent company	**556**	732
Redemptions —		
Senior notes	**—**	(16)
Payment of preference stock dividends	**(1,551)**	(1,551)
Payment of common stock dividends	**(28,850)**	(28,950)
Other financing activities	**(206)**	198
Net cash provided from (used for) financing activities	**15,758**	(16,925)
Net Change in Cash and Cash Equivalents	**(4,236)**	1,782
Cash and Cash Equivalents at Beginning of Period	**32,167**	17,328
Cash and Cash Equivalents at End of Period	**$ 27,931**	$ 19,110
Supplemental Cash Flow Information:		
Cash paid (received) during the period for —		
Interest (net of $601 and $493 capitalized for 2013 and 2012, respectively)	**$ 8,306**	$ 9,352
Income taxes, net	**3,886**	(35,742)
Noncash transactions — accrued property additions at end of period	**22,462**	28,788

The accompanying notes as they relate to Gulf Power are an integral part of these condensed financial statements.

GULF POWER COMPANY
CONDENSED BALANCE SHEETS (UNAUDITED)

Assets	At March 31, 2013	At December 31, 2012
	(in thousands)	
Current Assets:		
Cash and cash equivalents	**$ 27,931**	$ 32,167
Receivables —		
Customer accounts receivable	**61,190**	58,449
Unbilled revenues	**47,817**	53,363
Under recovered regulatory clause revenues	**15,153**	6,138
Other accounts and notes receivable	**13,019**	11,859
Affiliated companies	**8,709**	13,624
Accumulated provision for uncollectible accounts	**(1,261)**	(1,490)
Fossil fuel stock, at average cost	**152,287**	153,710
Materials and supplies, at average cost	**53,877**	53,365
Other regulatory assets, current	**20,475**	30,576
Prepaid expenses	**63,697**	62,877
Other current assets	**10,682**	2,690
Total current assets	**473,576**	477,328
Property, Plant, and Equipment:		
In service	**4,261,604**	4,260,844
Less accumulated provision for depreciation	**1,170,499**	1,168,055
Plant in service, net of depreciation	**3,091,105**	3,092,789
Construction work in progress	**178,025**	136,062
Total property, plant, and equipment	**3,269,130**	3,228,851
Other Property and Investments	**15,494**	15,737
Deferred Charges and Other Assets:		
Deferred charges related to income taxes	**50,664**	50,139
Other regulatory assets, deferred	**373,289**	372,294
Other deferred charges and assets	**33,531**	33,053
Total deferred charges and other assets	**457,484**	455,486
Total Assets	**$ 4,215,684**	$ 4,177,402

The accompanying notes as they relate to Gulf Power are an integral part of these condensed financial statements.

GULF POWER COMPANY
CONDENSED BALANCE SHEETS (UNAUDITED)

Liabilities and Stockholder's Equity	**At March 31, 2013**	At December 31, 2012
	(in thousands)	
Current Liabilities:		
Securities due within one year	**$ 60,000**	$ 60,000
Notes payable	**132,811**	127,002
Accounts payable —		
Affiliated	**60,226**	66,161
Other	**44,953**	54,551
Customer deposits	**34,950**	34,749
Accrued taxes —		
Accrued income taxes	**4,094**	45
Other accrued taxes	**12,302**	7,036
Accrued interest	**18,098**	12,364
Accrued compensation	**5,514**	14,966
Other regulatory liabilities, current	**18,903**	25,887
Liabilities from risk management activities	**7,782**	16,529
Other current liabilities	**20,429**	19,930
Total current liabilities	**420,062**	439,220
Long-term Debt	**1,186,022**	1,185,870
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	**660,762**	648,952
Accumulated deferred investment tax credits	**5,070**	5,408
Employee benefit obligations	**127,254**	126,871
Other cost of removal obligations	**218,801**	213,413
Other regulatory liabilities, deferred	**50,027**	47,863
Deferred capacity expense	**148,213**	137,568
Other deferred credits and liabilities	**86,514**	93,497
Total deferred credits and other liabilities	**1,296,641**	1,273,572
Total Liabilities	**2,902,725**	2,898,662
Preference Stock	**97,998**	97,998
Common Stockholder's Equity:		
Common stock, without par value—		
Authorized — 20,000,000 shares		
Outstanding — March 31, 2013: 4,942,717 shares		
— December 31, 2012: 4,542,717 shares	**433,060**	393,060
Paid-in capital	**548,933**	547,798
Retained earnings	**234,406**	241,465
Accumulated other comprehensive loss	**(1,438)**	(1,581)
Total common stockholder's equity	**1,214,961**	1,180,742
Total Liabilities and Stockholder's Equity	**$ 4,215,684**	$ 4,177,402

The accompanying notes as they relate to Gulf Power are an integral part of these condensed financial statements.

FIRST QUARTER 2013 vs. FIRST QUARTER 2012

OVERVIEW

Gulf Power operates as a vertically integrated utility providing electricity to retail customers within its traditional service area located in northwest Florida and to wholesale customers in the Southeast. Many factors affect the opportunities, challenges, and risks of Gulf Power's business of selling electricity. These factors include the ability to maintain a constructive regulatory environment, to maintain and grow energy sales given economic conditions, and to effectively manage and secure timely recovery of costs. These costs include those related to projected long-term demand growth, increasingly stringent environmental standards, reliability, restoration following major storms, and fuel. Appropriately balancing required costs and capital expenditures with customer prices will continue to challenge Gulf Power for the foreseeable future.

On May 9, 2013, in accordance with the Florida Administrative Code Rules, Gulf Power notified the Florida PSC of Gulf Power's intent to file for an increase in Gulf Power's base rates. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Retail Base Rate Case" herein for additional information.

Gulf Power continues to focus on several key performance indicators. These indicators include customer satisfaction, plant availability, system reliability, and net income after dividends on preference stock. For additional information on these indicators, see MANAGEMENT'S DISCUSSION AND ANALYSIS – OVERVIEW – "Key Performance Indicators" of Gulf Power in Item 7 of the Form 10-K.

RESULTS OF OPERATIONS

Net Income

First Quarter 2013 vs. First Quarter 2012	
(change in millions)	*(% change)*
$1.1	5.4

Gulf Power's net income after dividends on preference stock for the first quarter 2013 was $21.8 million compared to $20.7 million for the corresponding period in 2012. The increase was primarily due to higher retail base revenues resulting from the retail base rate increase effective April 2012 and more favorable weather in the first quarter 2013 compared to the corresponding period in 2012. The increase was partially offset by a decrease in customer usage in 2013, lower wholesale capacity revenues from non-affiliates in 2013, and an increase in depreciation in 2013.

Retail Revenues

First Quarter 2013 vs. First Quarter 2012	
(change in millions)	*(% change)*
$21.4	9.0

In the first quarter 2013, retail revenues were $259.9 million compared to $238.5 million for the corresponding period in 2012.

Details of the change to retail revenues were as follows:

	First Quarter 2013	
	(in millions)	*(% change)*
Retail – prior year	$ 238.5	
Estimated change in –		
Rates and pricing	5.8	2.4
Sales growth (decline)	(2.7)	(1.1)
Weather	3.6	1.5
Fuel and other cost recovery	14.7	6.2
Retail – current year	$ 259.9	9.0

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "PSC Matters" of Gulf Power in Item 7 and Note 1 to the financial statements of Gulf Power under "Revenues" and Note 3 to the financial statements of Gulf Power under "Retail Regulatory Matters" in Item 8 of the Form 10-K for additional information regarding Gulf Power's retail base rate case and cost recovery clauses, including Gulf Power's fuel cost recovery, purchased power capacity recovery, environmental cost recovery, and energy conservation cost recovery clauses.

Revenues associated with changes in rates and pricing increased in the first quarter 2013 when compared to the corresponding period in 2012 primarily due to an increase in retail base revenues resulting from the retail base rate increase effective April 2012.

Revenues attributable to changes in sales decreased in the first quarter 2013 when compared to the corresponding period in 2012. Weather-adjusted KWH energy sales to residential and commercial customers decreased 2.7% and 1.1%, respectively, primarily due to a decrease in customer usage. KWH energy sales to industrial customers decreased 2.8% primarily due to increased customer co-generation.

Revenues attributable to changes in weather increased in the first quarter 2013 when compared to the corresponding period in 2012 due to more favorable weather in the first quarter 2013.

Fuel and other cost recovery revenues increased in the first quarter 2013 when compared to the corresponding period in 2012 primarily due to higher revenues associated with recoverable fuel costs for generation and purchased power costs generally due to higher natural gas prices. Fuel and other cost recovery provisions include fuel expenses, the energy component of purchased power costs, purchased power capacity costs, and the difference between projected and actual costs and revenues related to energy conservation and environmental compliance. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Cost Recovery Clauses – Fuel Cost Recovery" herein for additional information.

Wholesale Revenues – Non-Affiliates

First Quarter 2013 vs. First Quarter 2012	
(change in millions)	*(% change)*
$(5.9)	(21.8)

Wholesale revenues from sales to non-affiliates will vary depending on fuel prices, the market prices of wholesale energy compared to the cost of Gulf Power's and the Southern Company system's generation, demand for energy within the Southern Company system's service territory, and the availability of the Southern Company system's generation. Wholesale revenues from sales to non-affiliates include unit power sales under long-term contracts to other utilities in Florida and Georgia. Wholesale revenues from these contracts have both capacity and energy components. Capacity revenues reflect the recovery of fixed costs and a return on investment under the contracts. Energy is generally sold at variable cost.

In the first quarter 2013, wholesale revenues from non-affiliates were $21.2 million compared to $27.1 million for the corresponding period in 2012. The decrease primarily resulted from lower energy revenues related to a 47.0% decrease in KWH sales as a result of less energy scheduled by unit power customers to serve their loads. The decrease was also due to a 12.6% decrease in revenues primarily related to certain contract provisions that allow for cost adjustments related to compliance with new environmental requirements.

Wholesale Revenues – Affiliates

First Quarter 2013 vs. First Quarter 2012	
(change in millions)	*(% change)*
$(6.9)	(19.0)

Wholesale revenues from sales to affiliated companies will vary depending on demand and the availability and cost of generating resources at each company. These affiliate sales are made in accordance with the IIC, as approved by the FERC. These transactions do not have a significant impact on earnings since the revenue related to these energy sales generally offsets the cost of energy sold.

In the first quarter 2013, wholesale revenues from sales to affiliates were $29.5 million compared to $36.4 million for the corresponding period in 2012. The decrease was primarily due to lower energy revenues related to a 32.4% decrease in KWH sales resulting from lower Gulf Power generation dispatched to serve affiliated companies' demand in the first quarter 2013 compared to the corresponding period in 2012. This decrease was partially offset by a 19.9% increase in the price of energy in the first quarter 2013.

Fuel and Purchased Power Expenses

	First Quarter 2013 vs. First Quarter 2012	
	(change in millions)	*(% change)*
Fuel	$ (0.2)	(0.2)
Purchased power – non-affiliates	(0.1)	(0.8)
Purchased power – affiliates	0.8	31.8
Total fuel and purchased power expenses	$ 0.5	

In the first quarter 2013, total fuel and purchased power expenses were $135.3 million compared to $134.8 million for the corresponding period in 2012. The increase in fuel and purchased power expenses was due to a $21.5 million increase in the average cost of fuel and purchased power, partially offset by a $21.0 million decrease related to the volume of KWHs generated and purchased.

Fuel and purchased power transactions do not have a significant impact on earnings since energy and capacity expenses are generally offset by energy and capacity revenues through Gulf Power's fuel cost and purchased power capacity recovery clauses. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Cost Recovery Clauses – Fuel Cost Recovery" and "– Purchased Power Capacity Recovery" herein for additional information.

Details of Gulf Power's generation and purchased power were as follows:

	First Quarter 2013	First Quarter 2012
Total generation *(millions of KWHs)*	**1,861**	2,341
Total purchased power *(millions of KWHs)*	**1,663**	1,750
Sources of generation *(percent)* –		
Coal	**52**	53
Gas	**48**	47
Cost of fuel, generated *(cents per net KWH)* –		
Coal	**4.68**	4.29
Gas	**3.72**	3.44
Average cost of fuel, generated *(cents per net KWH)*	**4.22**	3.89
Average cost of purchased power *(cents per net KWH)*[(a)]	**3.42**	2.50

(a) Average cost of purchased power includes fuel purchased by Gulf Power for tolling agreements where power is generated by the provider.

Fuel

In the first quarter 2013, fuel expense was $120.9 million compared to $121.1 million for the corresponding period in 2012. The decrease was not material.

Purchased Power – Non-Affiliates

In the first quarter 2013, purchased power expense from non-affiliates was $11.1 million compared to $11.2 million for the corresponding period in 2012. The decrease was not material.

Energy purchases from non-affiliates will vary depending on the market prices of wholesale energy as compared to the cost of the Southern Company system's generation, demand for energy within the Southern Company system's service territory, and the availability of the Southern Company system's generation.

Purchased Power – Affiliates

In the first quarter 2013, purchased power expense from affiliates was $3.3 million compared to $2.5 million for the corresponding period in 2012. The increase reflects an increase of $1.3 million in energy costs, offset by a decrease of $0.5 million in capacity costs. The increase in energy costs was due to an increase in the volume of KWHs purchased and a higher average cost per KWH purchased.

Energy purchases from affiliates will vary depending on demand and the availability and cost of generating resources at each company within the Southern Company system. These purchases are made in accordance with the IIC or other contractual agreements, all as approved by the FERC.

Other Operations and Maintenance Expenses

First Quarter 2013 vs. First Quarter 2012	
(change in millions)	*(% change)*
$3.4	4.6

In the first quarter 2013, other operations and maintenance expenses were $78.6 million compared to $75.2 million for the corresponding period in 2012. The increase was primarily due to increases of $1.5 million for transmission service related to a third party PPA, $1.3 million for labor and benefit-related expenses, and $1.3 million in marketing programs. The increased expense from transmission service did not have a significant impact on earnings since the expense was offset by purchased power capacity revenues through Gulf Power's purchased power capacity recovery clause. The increased expense from marketing programs did not have a significant impact on earnings

since the expense was offset by energy conservation revenues through Gulf Power's energy conservation cost recovery clause. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Cost Recovery Clauses – Purchased Power Capacity Recovery" and "– Energy Conservation Cost Recovery" herein for additional information.

Depreciation and Amortization

First Quarter 2013 vs. First Quarter 2012	
(change in millions)	*(% change)*
$3.7	11.2

In the first quarter 2013, depreciation and amortization was $37.0 million compared to $33.3 million for the corresponding period in 2012. The increase was primarily due to the addition of environmental control projects at generation facilities and other net additions to transmission and distribution facilities.

Interest Expense, Net of Amounts Capitalized

First Quarter 2013 vs. First Quarter 2012	
(change in millions)	*(% change)*
$(1.0)	(6.5)

In the first quarter 2013, interest expense, net of amounts capitalized was $14.4 million compared to $15.4 million for the corresponding period in 2012. The decrease was primarily due to lower interest rates on pollution control bonds, senior notes, and customer deposits.

Income Taxes

First Quarter 2013 vs. First Quarter 2012	
(change in millions)	*(% change)*
$2.4	20.0

In the first quarter 2013, income taxes were $14.1 million compared to $11.7 million for the corresponding period in 2012. The increase was primarily due to higher pre-tax earnings and the recognition in 2012 of previously unrecognized tax benefits.

FUTURE EARNINGS POTENTIAL

The results of operations discussed above are not necessarily indicative of Gulf Power's future earnings potential. The level of Gulf Power's future earnings depends on numerous factors that affect the opportunities, challenges, and risks of Gulf Power's business of selling electricity. These factors include Gulf Power's ability to maintain a constructive regulatory environment that continues to allow for the timely recovery of prudently-incurred costs during a time of increasing costs. Future earnings in the near term will depend, in part, upon maintaining energy sales which is subject to a number of factors. These factors include weather, competition, new energy contracts with neighboring utilities, energy conservation practiced by customers, the price of electricity, the price elasticity of demand, and the rate of economic growth or decline in Gulf Power's service territory. Changes in regional and global economic conditions may impact sales for Gulf Power as the pace of the economic recovery remains uncertain. The timing and extent of the economic recovery will impact growth and may impact future earnings. For additional information relating to these issues, see RISK FACTORS in Item 1A and MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL of Gulf Power in Item 7 of the Form 10-K.

Environmental Matters

Compliance costs related to federal and state environmental statutes and regulations could affect earnings if such costs cannot continue to be fully recovered in rates on a timely basis. Environmental compliance spending over the next several years may differ materially from the amounts estimated. The timing, specific requirements, and estimated costs could change as environmental statutes and regulations are adopted or modified. Further, higher costs that are recovered through regulated rates could contribute to reduced demand for electricity, which could negatively affect results of operations, cash flows, and financial condition. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters" of Gulf Power in Item 7 and Note 3 to the financial statements of Gulf Power under "Environmental Matters" in Item 8 of the Form 10-K for additional information.

Gulf Power has determined it is not economical to add the environmental controls at Plant Scholz necessary to comply with the MATS rule and that coal-fired generation at Plant Scholz will cease by April 2015. The plant is scheduled to be fully depreciated by April 2015.

Environmental Statutes and Regulations

Air Quality

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations – Air Quality" of Gulf Power in Item 7 of the Form 10-K for information regarding the EPA's MATS rule. On April 24, 2013, the EPA published a final reconsideration rule addressing new source standards within the MATS rule. Although the EPA had considered revisions to the startup and shutdown provisions of the MATS rule, a final decision on these provisions was deferred. The ultimate impact of this rulemaking will depend on the outcome of any additional rulemaking and/or legal challenges and, therefore, cannot be determined at this time.

Water Quality

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations – Water Quality" of Gulf Power in Item 7 of the Form 10-K for additional information regarding the EPA's proposed revision of the current steam electric effluent guidelines. On April 19, 2013, the EPA signed a proposed rule which requests comments on a range of potential regulatory options for addressing certain wastestreams from steam electric power plants. These regulations could result in the installation of additional controls at certain of Gulf Power's facilities, which could result in significant capital expenditures and compliance costs that could affect future unit retirement and replacement decisions. The ultimate impact of these proposed regulations will, however, depend on the specific requirements of the final rule and the outcome of any legal challenges and cannot be determined at this time.

PSC Matters

Retail Base Rate Case

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "PSC Matters – Retail Base Rate Case" of Gulf Power in Item 7 and Note 3 to the financial statements of Gulf Power under "Retail Regulatory Matters – Retail Base Rate Case" in Item 8 of the Form 10-K for additional information.

On May 9, 2013, in accordance with the Florida Administrative Code Rules, Gulf Power notified the Florida PSC of Gulf Power's intent to file for an increase in Gulf Power's base rates, not sooner than July 8, 2013 (60 days after the notification) and not later than July 22, 2013. Gulf Power is proposing the projected 12 months ending December 31, 2014 as the test year for the anticipated rate case filing. The proposed test year is a calendar year that corresponds to Gulf Power's fiscal year and largely corresponds with the first fiscal period that new, permanent rates could be in effect. Gulf Power currently estimates that an increase in annual revenues between $75 million and $80 million will be requested. The ultimate outcome of this matter cannot be determined at this time.

Cost Recovery Clauses

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "PSC Matters – Cost Recovery Clauses" of Gulf Power in Item 7 and Note 3 to the financial statements of Gulf Power under "Retail Regulatory Matters – Cost Recovery Clauses" in Item 8 of the Form 10-K for additional information.

Fuel Cost Recovery

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "PSC Matters – Cost Recovery Clauses – Fuel Cost Recovery" of Gulf Power in Item 7 and Notes 1 and 3 to the financial statements of Gulf Power under "Revenues" and "Retail Regulatory Matters – Cost Recovery Clauses – Fuel Cost Recovery," respectively, in Item 8 of the Form 10-K for additional information.

Over recovered fuel costs at March 31, 2013 totaled $5.1 million compared to $17.1 million at December 31, 2012. These amounts are included in other regulatory liabilities, current on Gulf Power's Condensed Balance Sheets herein.

Purchased Power Capacity Recovery

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "PSC Matters – Cost Recovery Clauses – Purchased Power Capacity Recovery" of Gulf Power in Item 7 and Notes 1 and 3 to the financial statements of Gulf Power under "Revenues" and "Retail Regulatory Matters – Cost Recovery Clauses – Purchased Power Capacity Recovery," respectively, in Item 8 of the Form 10-K for additional information.

At March 31, 2013, the over recovered purchased power capacity costs totaled $1.8 million, which is included in other regulatory liabilities, current on Gulf Power's Condensed Balance Sheets herein. At December 31, 2012, the under recovered purchased power capacity costs totaled $0.8 million, which is included in under recovered regulatory clause revenues on Gulf Power's Condensed Balance Sheets herein.

Environmental Cost Recovery

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "PSC Matters – Cost Recovery Clauses – Environmental Cost Recovery" of Gulf Power in Item 7 and Note 3 to the financial statements of Gulf Power under "Retail Regulatory Matters – Cost Recovery Clauses – Environmental Cost Recovery" in Item 8 of the Form 10-K for additional information.

Under recovered environmental costs at March 31, 2013 totaled $8.9 million compared to $1.9 million at December 31, 2012. These amounts are included in under recovered regulatory clause revenues on Gulf Power's Condensed Balance Sheets herein.

Energy Conservation Cost Recovery

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "PSC Matters – Cost Recovery Clauses – Energy Conservation Cost Recovery" of Gulf Power in Item 7 and Note 3 to the financial statements of Gulf Power under "Retail Regulatory Matters – Cost Recovery Clauses – Energy Conservation Cost Recovery" in Item 8 of the Form 10-K for additional information.

Under recovered energy conservation costs at March 31, 2013 totaled $3.0 million compared to $0.8 million at December 31, 2012. These amounts are included in under recovered regulatory clause revenues on Gulf Power's Condensed Balance Sheets herein.

Other Matters

Gulf Power is involved in various other matters being litigated and regulatory matters that could affect future earnings. In addition, Gulf Power is subject to certain claims and legal actions arising in the ordinary course of business. Gulf Power's business activities are subject to extensive governmental regulation related to public health and the environment, such as regulation of air emissions and water discharges. Litigation over environmental issues

and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements, such as air quality and water standards, has increased generally throughout the U.S. In particular, personal injury, property damage, and other claims for damages alleged to have been caused by carbon dioxide and other emissions, coal combustion byproducts, and alleged exposure to hazardous materials, and/or requests for injunctive relief in connection with such matters, have become more frequent. The ultimate outcome of such pending or potential litigation against Gulf Power cannot be predicted at this time; however, for current proceedings not specifically reported in Note (B) to the Condensed Financial Statements herein or in Note 3 to the financial statements of Gulf Power in Item 8 of the Form 10-K, management does not anticipate that the ultimate liabilities, if any, arising from such current proceedings would have a material effect on Gulf Power's financial statements.

See the Notes to the Condensed Financial Statements herein for a discussion of various other contingencies, regulatory matters, and other matters being litigated which may affect future earnings potential.

ACCOUNTING POLICIES

Application of Critical Accounting Policies and Estimates

Gulf Power prepares its financial statements in accordance with GAAP. Significant accounting policies are described in Note 1 to the financial statements of Gulf Power in Item 8 of the Form 10-K. In the application of these policies, certain estimates are made that may have a material impact on Gulf Power's results of operations and related disclosures. Different assumptions and measurements could produce estimates that are significantly different from those recorded in the financial statements. See MANAGEMENT'S DISCUSSION AND ANALYSIS – ACCOUNTING POLICIES – "Application of Critical Accounting Policies and Estimates" of Gulf Power in Item 7 of the Form 10-K for a complete discussion of Gulf Power's critical accounting policies and estimates related to Electric Utility Regulation, Contingent Obligations, and Pension and Other Postretirement Benefits.

FINANCIAL CONDITION AND LIQUIDITY

Overview

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FINANCIAL CONDITION AND LIQUIDITY – "Overview" of Gulf Power in Item 7 of the Form 10-K for additional information. Gulf Power's financial condition remained stable at March 31, 2013. Gulf Power intends to continue to monitor its access to short-term and long-term capital markets as well as its bank credit arrangements to meet future capital and liquidity needs. See "Sources of Capital," "Financing Activities," and "Capital Requirements and Contractual Obligations" herein for additional information.

Net cash provided from operating activities totaled $49.7 million for the first three months of 2013 compared to $117.5 million for the corresponding period in 2012. The $67.8 million decrease was primarily due to decreases in deferred income taxes related to bonus depreciation, prepaid income taxes, and the recovery of fuel costs. Net cash used for investing activities totaled $69.7 million in the first three months of 2013 primarily due to property additions to utility plant and costs of removal. Net cash provided from financing activities totaled $15.8 million for the first three months of 2013. This was primarily due to issuances of common stock and an increase in notes payable, partially offset by payment of common stock dividends. Fluctuations in cash flow from financing activities vary from year to year based on capital needs and the maturity or redemption of securities.

Significant balance sheet changes for the first three months of 2013 include a net increase of $40.3 million in property, plant, and equipment, primarily due to the addition of environmental control projects at generation facilities and other net additions to transmission and distribution facilities and an increase in common stock due to the issuance of common stock to Southern Company for $40 million.

Capital Requirements and Contractual Obligations

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" of Gulf Power in Item 7 of the Form 10-K for a description of Gulf Power's capital requirements for its construction program, including estimated capital expenditures to comply with existing environmental statutes and regulations, scheduled maturities of long-term debt, as well as the related interest, leases, derivative obligations, preference stock dividends, purchase commitments, trust funding requirements, and unrecognized tax benefits. See FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations" herein for additional information. Approximately $60 million will be required through March 31, 2014 to fund maturities of long-term debt.

The construction program is subject to periodic review and revision, and actual construction costs may vary from these estimates because of numerous factors. These factors include: changes in business conditions; changes in load projections; storm impacts; changes in environmental statutes and regulations; the outcome of any legal challenges to the environmental rules; changes in generating plants, including unit retirements and replacements and adding or changing fuel sources at existing units, to meet regulatory requirements; changes in the expected environmental compliance programs; changes in FERC rules and regulations; Florida PSC approvals; changes in legislation; the cost and efficiency of construction labor, equipment, and materials; project scope and design changes; and the cost of capital. In addition, there can be no assurance that costs related to capital expenditures will be fully recovered.

Sources of Capital

Gulf Power plans to obtain the funds required for construction and other purposes from sources similar to those used in the past, which were primarily from operating cash flows, short-term debt, security issuances, term loans, and equity contributions from Southern Company. However, the amount, type, and timing of any future financings, if needed, will depend upon regulatory approval, prevailing market conditions, and other factors. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FINANCIAL CONDITION AND LIQUIDITY – "Sources of Capital" of Gulf Power in Item 7 of the Form 10-K for additional information.

Gulf Power's current liabilities frequently exceed current assets because of the continued use of short-term debt as a funding source to meet scheduled maturities of long-term debt, as well as cash needs, which can fluctuate significantly due to the seasonality of the business.

At March 31, 2013, Gulf Power had approximately $27.9 million of cash and cash equivalents. Committed credit arrangements with banks at March 31, 2013 were as follows:

Expires[a]					Executable Term Loans		Due Within One Year	
2013	2014	2016	Total	Unused	One Year	Two Years	Term Out	No Term Out
(in millions)			*(in millions)*		*(in millions)*		*(in millions)*	
$ 45	$ 60	$ 165	$ 270	$ 270	$ 45	$ —	$ 45	$ 30

(a) No credit arrangements expire in 2015.

See Note 6 to the financial statements of Gulf Power under "Bank Credit Arrangements" in Item 8 of the Form 10-K and Note (E) to the Condensed Financial Statements under "Bank Credit Arrangements" herein for additional information.

These credit arrangements provide liquidity support to Gulf Power's commercial paper borrowings and variable rate pollution control revenue bonds. The amount of variable rate pollution control revenue bonds outstanding requiring liquidity support as of March 31, 2013 was approximately $69 million. In addition, Gulf Power has substantial cash flows from operating activities and access to the capital markets to meet liquidity needs.

In March 2013, Gulf Power amended several credit arrangements, which extended the maturity dates from 2014 to 2016. Gulf Power also amended a $35 million credit arrangement, which reduced the amount to $30 million and

extended the maturity date from 2013 to 2014. Subsequent to March 31, 2013, Gulf Power entered into a new credit arrangement for $5 million with a maturity date of 2014.

Most of these arrangements contain covenants that limit debt levels and contain cross default provisions that are restricted only to the indebtedness of Gulf Power. Gulf Power is currently in compliance with all such covenants. Gulf Power expects to renew its credit arrangements, as needed, prior to expiration.

Gulf Power may also meet short-term cash needs through a Southern Company subsidiary organized to issue and sell commercial paper at the request and for the benefit of Gulf Power and the other traditional operating companies. Proceeds from such issuances for the benefit of Gulf Power are loaned directly to Gulf Power. The obligations of each company under these arrangements are several and there is no cross affiliate credit support.

Details of short-term borrowings were as follows:

	Short-term Debt at March 31, 2013		Short-term Debt During the Period[a]		
	Amount Outstanding	Weighted Average Interest Rate	Average Outstanding	Weighted Average Interest Rate	Maximum Amount Outstanding
	(in millions)		*(in millions)*		*(in millions)*
Commercial paper	$ 130	0.3%	$ 114	0.3%	$ 130

(a) Average and maximum amounts are based upon daily balances during the three-month period ended March 31, 2013.

Management believes that the need for working capital can be adequately met by utilizing the commercial paper program, lines of credit, and cash.

Credit Rating Risk

Gulf Power does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. There are certain contracts that could require collateral, but not accelerated payment, in the event of a credit rating change to BBB- and/or Baa3 or below. These contracts are for physical electricity purchases and sales, fuel transportation and storage, and energy price risk management. The maximum potential collateral requirements under these contracts at March 31, 2013 were as follows:

Credit Ratings	Maximum Potential Collateral Requirements
	(in millions)
At BBB- and/or Baa3	$ 117
Below BBB- and/or Baa3	484

Included in these amounts are certain agreements that could require collateral in the event that one or more Power Pool participant has a credit rating change to below investment grade. Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. Additionally, any credit rating downgrade could impact Gulf Power's ability to access capital markets, particularly the short-term debt market and the variable rate pollution control revenue bond markets.

Market Price Risk

Gulf Power's market risk exposure relative to interest rate changes for the first quarter 2013 has not changed materially compared with the December 31, 2012 reporting period. Since a significant portion of outstanding indebtedness is at fixed rates, Gulf Power is not aware of any facts or circumstances that would significantly affect exposures on existing indebtedness in the near term. However, the impact on future financing costs cannot now be determined.

Due to cost-based rate regulation and other various cost recovery mechanisms, Gulf Power continues to have limited exposure to market volatility in interest rates, commodity fuel prices, and prices of electricity. To mitigate residual risks relative to natural gas purchases, Gulf Power continues to manage a financial hedging program for fuel purchased to operate its electric generating fleet implemented per the guidelines of the Florida PSC. As a result, Gulf Power had no material change in market risk exposure for the first quarter 2013 when compared with the December 31, 2012 reporting period.

The changes in fair value of energy-related derivative contracts, substantially all of which are composed of regulatory hedges, for the three months ended March 31, 2013 were as follows:

	First Quarter 2013 Changes
	Fair Value
	(in millions)
Contracts outstanding at the beginning of the period, assets (liabilities), net	$ (23)
Contracts realized or settled	5
Current period changes[(a)]	16
Contracts outstanding at the end of the period, assets (liabilities), net	$ (2)

(a) Current period changes also include the changes in fair value of new contracts entered into during the period, if any.

The changes in the fair value positions of the energy-related derivative contracts, which are substantially all attributable to both the volume and the price of natural gas, for the three months ended March 31, 2013 were as follows:

	First Quarter 2013 Changes
	Fair Value
	(in millions)
Natural gas swaps	$ 21
Natural gas options	—
Total changes	$ 21

The net hedge volumes of energy-related derivative contracts were as follows:

	March 31, 2013	December 31, 2012
	mmBtu Volume	
	(in millions)	
Commodity – Natural gas swaps	**70**	71
Commodity – Natural gas options	—	—
Total hedge volume	**70**	71

The weighted average swap contract cost above market prices was approximately $0.02 per mmBtu as of March 31, 2013 and $0.32 per mmBtu as of December 31, 2012. The change in option fair value is primarily attributable to the volatility of the market and the underlying change in the natural gas price. Natural gas settlements are recovered through Gulf Power's fuel cost recovery clause.

Regulatory hedges relate to Gulf Power's fuel-hedging program where gains and losses are initially recorded as regulatory liabilities and assets, respectively, and then are included in fuel expense as they are recovered through Gulf Power's fuel cost recovery clause.

Unrealized pre-tax gains and losses recognized in income for the three months ended March 31, 2013 and 2012 for energy-related derivative contracts that are not hedges were not material.

Gulf Power uses over-the-counter contracts that are not exchange traded but are fair valued using prices which are market observable, and thus fall into Level 2. See Note (C) to the Condensed Financial Statements herein for further discussion on fair value measurements. The maturities of the energy-related derivative contracts, which are all Level 2 of the fair value hierarchy, at March 31, 2013 were as follows:

	March 31, 2013 Fair Value Measurements			
	Total Fair Value	Maturity		
		Year 1	Years 2&3	Years 4&5
		(in millions)		
Level 1	$ —	$ —	$ —	$ —
Level 2	(2)	1	(2)	(1)
Level 3	—	—	—	—
Fair value of contracts outstanding at end of period	$ (2)	$ 1	$ (2)	$ (1)

For additional information, see MANAGEMENT'S DISCUSSION AND ANALYSIS – FINANCIAL CONDITION AND LIQUIDITY – "Market Price Risk" of Gulf Power in Item 7 and Note 1 under "Financial Instruments" and Note 10 to the financial statements of Gulf Power in Item 8 of the Form 10-K and Note (H) to the Condensed Financial Statements herein.

Financing Activities

In February 2013, Gulf Power issued to Southern Company 400,000 shares of Gulf Power's common stock and realized proceeds of $40 million. The proceeds were used to repay a portion of Gulf Power's short-term debt and for other general corporate purposes, including Gulf Power's continuous construction program.

In addition to any financings that may be necessary to meet capital requirements, contractual obligations, and storm-recovery, Gulf Power plans to continue, when economically feasible, a program to retire higher-cost securities and replace these obligations with lower-cost capital if market conditions permit.

MISSISSIPPI POWER COMPANY

MISSISSIPPI POWER COMPANY
CONDENSED STATEMENTS OF OPERATIONS (UNAUDITED)

	For the Three Months Ended March 31,	
	2013	2012
	(in thousands)	
Operating Revenues:		
Retail revenues	**$ 168,310**	$ 166,271
Wholesale revenues, non-affiliates	**65,109**	54,231
Wholesale revenues, affiliates	**8,341**	4,040
Other revenues	**4,174**	4,172
Total operating revenues	**245,934**	228,714
Operating Expenses:		
Fuel	**104,564**	88,619
Purchased power, non-affiliates	**1,367**	1,943
Purchased power, affiliates	**9,689**	8,860
Other operations and maintenance	**54,812**	54,895
Depreciation and amortization	**23,233**	22,481
Taxes other than income taxes	**19,417**	21,703
Estimated loss on Kemper IGCC	**462,000**	—
Total operating expenses	**675,082**	198,501
Operating Income (Loss)	**(429,148)**	30,213
Other Income and (Expense):		
Allowance for equity funds used during construction	**26,074**	11,827
Interest expense, net of amounts capitalized	**(10,409)**	(7,805)
Other income (expense), net	**(1,547)**	(122)
Total other income and (expense)	**14,118**	3,900
Earnings (Loss) Before Income Taxes	**(415,030)**	34,113
Income taxes (benefit)	**(169,142)**	8,425
Net Income (Loss)	**(245,888)**	25,688
Dividends on Preferred Stock	**433**	433
Net Income (Loss) After Dividends on Preferred Stock	**$ (246,321)**	$ 25,255

CONDENSED STATEMENTS OF COMPREHENSIVE INCOME (LOSS) (UNAUDITED)

	For the Three Months Ended March 31,	
	2013	2012
	(in thousands)	
Net Income (Loss)	**$ (245,888)**	$ 25,688
Other comprehensive income (loss):		
Qualifying hedges:		
Changes in fair value, net of tax of $- and $(296), respectively	**—**	(478)
Reclassification adjustment for amounts included in net income, net of tax of $131 and $16, respectively	**212**	26
Total other comprehensive income (loss)	**212**	(452)
Comprehensive Income (Loss)	**$ (245,676)**	$ 25,236

The accompanying notes as they relate to Mississippi Power are an integral part of these condensed financial statements.

MISSISSIPPI POWER COMPANY
CONDENSED STATEMENTS OF CASH FLOWS (UNAUDITED)

	For the Three Months Ended March 31,	
	2013	2012
	(in thousands)	
Operating Activities:		
Net income (loss)	**$ (245,888)**	$ 25,688
Adjustments to reconcile net income (loss) to net cash provided from (used for) operating activities —		
Depreciation and amortization, total	**21,692**	21,931
Deferred income taxes	**(174,082)**	(1,210)
Investment tax credits received	**—**	13,974
Allowance for equity funds used during construction	**(26,074)**	(11,827)
Pension, postretirement, and other employee benefits	**2,926**	2,268
Hedge settlements	**—**	(15,983)
Stock based compensation expense	**1,033**	957
Regulatory assets associated with Kemper IGCC	**(6,843)**	(2,243)
Estimated loss on Kemper IGCC	**462,000**	—
Other, net	**(628)**	1,117
Changes in certain current assets and liabilities —		
-Receivables	**(5,226)**	14,536
-Fossil fuel stock	**8,415**	(16,188)
-Materials and supplies	**(4,744)**	(538)
-Prepaid income taxes	**1,573**	4,168
-Other current assets	**(2,389)**	(4,357)
-Accounts payable	**(13,783)**	(11,558)
-Accrued taxes	**(45,429)**	(31,434)
-Accrued interest	**6,570**	9,514
-Accrued compensation	**(10,247)**	(10,803)
-Over recovered regulatory clause revenues	**2,996**	12,627
-Other current liabilities	**2,971**	(35)
Net cash provided from (used for) operating activities	**(25,157)**	604
Investing Activities:		
Property additions	**(369,313)**	(370,923)
Cost of removal, net of salvage	**(902)**	(1,149)
Construction payables	**23,150**	30,080
Capital grant proceeds	**1,784**	1,816
Other investing activities	**(7,145)**	(4,207)
Net cash used for investing activities	**(352,426)**	(344,383)
Financing Activities:		
Proceeds —		
Capital contributions from parent company	**100,552**	150,735
Bonds-Other	**15,814**	—
Senior notes issuances	**—**	400,000
Interest-bearing refundable deposit related to asset sale	**—**	150,000
Other long-term debt issuances	**350,000**	—
Redemptions —		
Capital leases	**—**	(377)
Other long-term debt	**—**	(75,000)
Payment of preferred stock dividends	**(433)**	(433)
Payment of common stock dividends	**(44,190)**	(26,700)
Other financing activities	**(1,409)**	715
Net cash provided from financing activities	**420,334**	598,940
Net Change in Cash and Cash Equivalents	**42,751**	255,161
Cash and Cash Equivalents at Beginning of Period	**145,008**	211,585
Cash and Cash Equivalents at End of Period	**$ 187,759**	$ 466,746
Supplemental Cash Flow Information:		
Cash paid (received) during the period for —		
Interest (paid $16,001 and $5,965, net of $11,141 and $6,565 capitalized for 2013 and 2012, respectively)	**$ 4,860**	$ —
Income taxes, net	**(25)**	(11,994)
Noncash transactions—accrued property additions at end of period	**238,013**	165,982

The accompanying notes as they relate to Mississippi Power are an integral part of these condensed financial statements.

MISSISSIPPI POWER COMPANY
CONDENSED BALANCE SHEETS (UNAUDITED)

Assets	At March 31, 2013	At December 31, 2012
	(in thousands)	
Current Assets:		
Cash and cash equivalents	**$ 187,759**	$ 145,008
Receivables —		
Customer accounts receivable	**32,288**	29,561
Unbilled revenues	**33,324**	32,688
Other accounts and notes receivable	**5,851**	7,517
Affiliated companies	**31,475**	27,160
Accumulated provision for uncollectible accounts	**(298)**	(373)
Fossil fuel stock, at average cost	**167,963**	176,378
Materials and supplies, at average cost	**39,004**	34,260
Other regulatory assets, current	**53,058**	55,302
Prepaid income taxes	**173,818**	129,835
Other current assets	**33,268**	17,170
Total current assets	**757,510**	654,506
Property, Plant, and Equipment:		
In service	**3,073,750**	3,036,159
Less accumulated provision for depreciation	**1,083,639**	1,065,474
Plant in service, net of depreciation	**1,990,111**	1,970,685
Construction work in progress	**2,289,256**	2,393,145
Total property, plant, and equipment	**4,279,367**	4,363,830
Other Property and Investments	**4,836**	4,887
Deferred Charges and Other Assets:		
Deferred charges related to income taxes	**81,855**	71,869
Other regulatory assets, deferred	**244,585**	236,225
Other deferred charges and assets	**36,943**	42,304
Total deferred charges and other assets	**363,383**	350,398
Total Assets	**$ 5,405,096**	$ 5,373,621

The accompanying notes as they relate to Mississippi Power are an integral part of these condensed financial statements.

MISSISSIPPI POWER COMPANY
CONDENSED BALANCE SHEETS (UNAUDITED)

Liabilities and Stockholder's Equity	**At March 31, 2013**	At December 31, 2012
	(in thousands)	
Current Liabilities:		
Securities due within one year	**$ 342,285**	$ 276,471
Interest-bearing refundable deposit related to asset sale	**150,000**	150,000
Accounts payable —		
Affiliated	**53,795**	54,769
Other	**273,305**	262,992
Customer deposits	**14,415**	14,202
Accrued taxes —		
Accrued income taxes	**4,750**	2,339
Other accrued taxes	**21,951**	69,376
Accrued interest	**36,946**	30,376
Accrued compensation	**5,459**	15,706
Other regulatory liabilities, current	**10,863**	5,376
Over recovered regulatory clause liabilities	**80,333**	77,338
Liabilities from risk management activities	**6,671**	13,116
Other current liabilities	**19,200**	18,766
Total current liabilities	**1,019,973**	990,827
Long-term Debt	**1,869,056**	1,564,462
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	**80,676**	244,958
Deferred credits related to income taxes	**9,676**	10,106
Accumulated deferred investment tax credits	**420,678**	370,554
Employee benefit obligations	**157,542**	157,421
Other cost of removal obligations	**148,190**	143,461
Other regulatory liabilities, deferred	**56,457**	56,984
Other deferred credits and liabilities	**49,842**	52,860
Total deferred credits and other liabilities	**923,061**	1,036,344
Total Liabilities	**3,812,090**	3,591,633
Redeemable Preferred Stock	**32,780**	32,780
Common Stockholder's Equity:		
Common stock, without par value —		
Authorized —1,130,000 shares		
Outstanding—1,121,000 shares	**37,691**	37,691
Paid-in capital	**1,502,836**	1,401,520
Retained earnings	**28,199**	318,710
Accumulated other comprehensive loss	**(8,500)**	(8,713)
Total common stockholder's equity	**1,560,226**	1,749,208
Total Liabilities and Stockholder's Equity	**$ 5,405,096**	$ 5,373,621

The accompanying notes as they relate to Mississippi Power are an integral part of these condensed financial statements.

FIRST QUARTER 2013 vs. FIRST QUARTER 2012

OVERVIEW

Mississippi Power operates as a vertically integrated utility providing electricity to retail customers within its traditional service territory located within the State of Mississippi and to wholesale customers in the Southeast. Many factors affect the opportunities, challenges, and risks of Mississippi Power's business of selling electricity. These factors include the ability to maintain a constructive regulatory environment, to maintain and grow energy sales given economic conditions, and to effectively manage and secure timely recovery of rising costs. These costs include those related to projected long-term demand growth, increasingly stringent environmental standards, reliability, fuel, capital expenditures, and restoration following major storms. In addition, Mississippi Power is currently constructing the Kemper IGCC. Mississippi Power has various regulatory mechanisms that operate to address cost recovery. Appropriately balancing required costs and capital expenditures with customer prices will continue to challenge Mississippi Power for the foreseeable future.

On March 5, 2013, the Mississippi PSC issued an order with respect to Mississippi Power's request for an increase in rates which allows Mississippi Power an annual rate designed to collect $125 million for 2013, with such amounts to be recorded as a regulatory liability to be used to mitigate rate impacts when the Kemper IGCC is placed in service, increasing to $156 million in 2014, which represents a 15% and 3% increase in retail rates for 2013 and 2014, respectively. Also on March 5, 2013, the Mississippi PSC approved a $15.3 million, or 1.9%, increase in annual rates under Mississippi Power's PEP and a $35.5 million, or 4.7%, decrease in annual rates due to an annual adjustment to the retail fuel cost recovery factor, with all new rates effective March 19, 2013.

On April 23, 2013, Mississippi Power revised its cost estimate for the Kemper IGCC to approximately $3.42 billion, net of the DOE Grants and certain exceptions to the $2.88 billion cost cap established by the Mississippi PSC. For additional information on the Kemper IGCC, see MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Integrated Coal Gasification Combined Cycle" of Mississippi Power in Item 7 of the Form 10-K/A, Note 3 to the financial statements of Mississippi Power under "Integrated Coal Gasification Combined Cycle" in Item 8 of the Form 10-K/A and FUTURE EARNINGS POTENTIAL – "Integrated Coal Gasification Combined Cycle" and Note (B) to the Condensed Financial Statements under "Integrated Coal Gasification Combined Cycle" herein.

Mississippi Power continues to focus on several key performance indicators. In recognition that Mississippi Power's long-term financial success is dependent upon how well it satisfies its customers' needs, Mississippi Power's retail base rate mechanism, PEP, includes performance indicators that directly tie customer service indicators to Mississippi Power's allowed return. In addition to the PEP performance indicators, Mississippi Power focuses on other performance measures, including broader measures of customer satisfaction, plant availability, system reliability, and net income after dividends on preferred stock. For additional information on these indicators, see MANAGEMENT'S DISCUSSION AND ANALYSIS – OVERVIEW – "Key Performance Indicators" of Mississippi Power in Item 7 of the Form 10-K/A.

RESULTS OF OPERATIONS

Net Income (Loss)

First Quarter 2013 vs. First Quarter 2012	
(change in millions)	*(% change)*
$(271.6)	N/M

N/M - Not meaningful

Mississippi Power's net loss after dividends on preferred stock for the first quarter 2013 was $246.3 million compared to net income after dividends on preferred stock of $25.3 million for the corresponding period in 2012. The decrease was primarily related to a revision of estimated costs expected to be incurred on Mississippi Power's construction of the Kemper IGCC above the $2.88 billion cost cap established by the Mississippi PSC, net of $245 million of grants awarded to the project by the DOE under the Clean Coal Power Initiative Round 2 (DOE Grants) and the cost of the lignite mine and equipment, the cost of the carbon dioxide (CO_2) pipeline facilities, AFUDC, and certain general exceptions, including change of law, force majeure, and beneficial capital (which exists when Mississippi Power demonstrates that the purpose and effect of the construction cost increase is to produce efficiencies that will result in a neutral or favorable effect on customers relative to the original proposal for the CPCN) (Cost Cap Exceptions). The loss was partially offset by an increase in AFUDC equity primarily related to the construction of the Kemper IGCC and an increase in territorial base revenues primarily due to a wholesale base rate increase effective April 1, 2012.

Retail Revenues

First Quarter 2013 vs. First Quarter 2012	
(change in millions)	*(% change)*
$2.0	1.2

In the first quarter 2013, retail revenues were $168.3 million compared to $166.3 million for the corresponding period in 2012.

Details of the change to retail revenues were as follows:

		First Quarter 2013	
		(in millions)	*(% change)*
Retail – prior year	$	166.3	
Estimated change in –			
Rates and pricing		(3.7)	(2.2)
Sales growth (decline)		(2.9)	(1.7)
Weather		3.5	2.1
Fuel and other cost recovery		5.1	3.1
Retail – current year	$	168.3	1.3%

Revenues associated with changes in rates and pricing decreased in the first quarter 2013 when compared to the corresponding period in 2012 primarily due to a $4.7 million accrual for a retail refund related to the annual PEP lookback filing. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "PSC Matters – Performance Evaluation Plan" herein for additional information.

Revenues attributable to changes in sales decreased in the first quarter 2013 when compared to the corresponding period in 2012. Weather-adjusted KWH energy sales to residential and commercial customers decreased 1.8% and 1.4%, respectively, when compared to the corresponding period in 2012 due to decreased economic activity. KWH energy sales to industrial customers decreased 4.1% due to decreased production for several larger customers.

Revenues attributable to changes in weather increased in the first quarter 2013 when compared to the corresponding period in 2012 primarily due to more favorable weather in the first quarter 2013.

Fuel and other cost recovery revenues increased in the first quarter 2013 when compared to the corresponding period in 2012 primarily as a result of higher recoverable fuel costs. Recoverable fuel costs include fuel and purchased power expenses reduced by the fuel portion of wholesale revenues from energy sold to customers outside Mississippi Power's service territory. Electric rates include provisions to adjust billings for fluctuations in fuel costs, including the energy component of purchased power costs. Under these provisions, fuel revenues generally equal fuel expenses, including the energy component of purchased power costs, and do not affect net income.

The retail portion of ad valorem tax expense is recoverable under Mississippi Power's ad valorem tax cost recovery clause and, therefore, does not affect net income.

Wholesale Revenues – Non-Affiliates

First Quarter 2013 vs. First Quarter 2012	
(change in millions)	*(% change)*
$10.9	20.1

Wholesale revenues from sales to non-affiliates will vary depending on fuel prices, the market prices of wholesale energy compared to the cost of Mississippi Power's and the Southern Company system's generation, demand for energy within the Southern Company system's service territory, and the availability of the Southern Company system's generation. Increases and decreases in revenues that are driven by fuel prices are accompanied by an increase or decrease in fuel costs and do not have a significant impact on net income.

In the first quarter 2013, wholesale revenues from non-affiliates were $65.1 million compared to $54.2 million for the corresponding period in 2012. The increase was due to a $6.3 million increase in revenues primarily resulting from a wholesale base rate increase effective April 1, 2012 and a $4.6 million increase in energy revenues, of which $2.4 million was associated with higher fuel prices and $2.2 million was associated with an increase in KWH sales due to higher demand resulting from more favorable weather in the first quarter 2013 compared to the corresponding period in 2012.

Wholesale Revenues – Affiliates

First Quarter 2013 vs. First Quarter 2012	
(change in millions)	*(% change)*
$4.3	N/M

N/M - Not meaningful

Wholesale revenues from sales to affiliated companies will vary depending on demand and the availability and cost of generating resources at each company. These affiliated sales and purchases are made in accordance with the IIC, as approved by the FERC. These transactions do not have a significant impact on earnings since the energy is generally sold at marginal cost.

In the first quarter 2013, wholesale revenues from affiliates were $8.3 million compared to $4.0 million for the corresponding period in 2012. The increase was primarily due to a $4.4 million increase in energy revenues, of which $3.0 million was associated with an increase in KWH sales and $1.4 million was associated with higher energy prices.

Fuel and Purchased Power Expenses

	First Quarter 2013 vs. First Quarter 2012	
	(change in millions)	*(% change)*
Fuel	$ 16.0	18.0
Purchased power – non-affiliates	(0.6)	(29.6)
Purchased power – affiliates	0.8	9.4
Total fuel and purchased power expenses	$ 16.2	

In the first quarter 2013, total fuel and purchased power expenses were $115.6 million compared to $99.4 million for the corresponding period in 2012. The increase was primarily due to a $9.4 million increase in the total volume of KWHs generated and purchased and a $6.8 million increase in the cost of fuel and purchased power.

Fuel and purchased power energy transactions do not have a significant impact on earnings since energy expenses are generally offset by energy revenues through Mississippi Power's fuel cost recovery clause. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Fuel Cost Recovery" herein for additional information.

Details of Mississippi Power's generation and purchased power were as follows:

	First Quarter 2013	First Quarter 2012
Total generation *(millions of KWHs)*	**3,204**	2,982
Total purchased power *(millions of KWHs)*	**393**	447
Sources of generation *(percent)* –		
Coal	**27**	21
Gas	**73**	79
Cost of fuel, generated *(cents per net KWH)* –		
Coal	**5.03**	4.77
Gas	**2.98**	2.83
Average cost of fuel, generated *(cents per net KWH)*	**3.57**	3.29
Average cost of purchased power *(cents per net KWH)*	**2.82**	2.42

Fuel

In the first quarter 2013, fuel expense was $104.6 million compared to $88.6 million for the corresponding period in 2012. The increase was primarily due to an 8.5% increase in the average cost of fuel per KWH generated and an 8.6% increase in the volume of KWHs generated resulting from higher energy demand in the first quarter 2013 compared to the corresponding period in 2012.

Purchased Power – Non-Affiliates

In the first quarter 2013, purchased power expense from non-affiliates was $1.3 million compared to $1.9 million for the corresponding period in 2012. The decrease was primarily the result of a 20.0% decrease in the volume of KWHs purchased and a 12.3% decrease in the average cost per KWH purchased.

Energy purchases from non-affiliates will vary depending on the market prices of wholesale energy compared to the cost of the Southern Company system's generation, demand for energy within the Southern Company system's service territory, and the availability of the Southern Company system's generation.

Purchased Power – Affiliates

In the first quarter 2013, purchased power expense from affiliates was $9.7 million compared to $8.9 million for the corresponding period in 2012. The increase was primarily due to a 21.8% increase in the average cost per KWH purchased, partially offset by a 9.9% decrease in the volume of KWHs purchased.

Energy purchases from affiliates will vary depending on demand for energy and the availability and cost of generating resources at each company within the Southern Company system. These purchases are made in accordance with the IIC, as approved by the FERC.

Other Operations and Maintenance Expenses

First Quarter 2013 vs. First Quarter 2012	
(change in millions)	*(% change)*
$(0.1)	(0.2)

In the first quarter 2013, other operations and maintenance expenses were $54.8 million compared to $54.9 million for the corresponding period in 2012. The decrease was primarily due to a $2.1 million decrease in generation maintenance expenses related to scheduled outages and a $0.8 million decrease in distribution expenses related to overhead line maintenance and vegetation management costs. These decreases were partially offset by a $3.1 million increase in administrative and general expenses.

Taxes Other Than Income Taxes

First Quarter 2013 vs. First Quarter 2012	
(change in millions)	*(% change)*
$(2.3)	(10.5)

In the first quarter 2013, taxes other than income taxes were $19.4 million compared to $21.7 million for the corresponding period in 2012. The decrease was primarily due to a $1.8 million decrease in ad valorem taxes and a $0.4 million decrease in franchise taxes. The retail portion of ad valorem taxes is recoverable under Mississippi Power's ad valorem tax cost recovery clause and, therefore, does not affect net income.

Estimated Loss on Kemper IGCC

First Quarter 2013 vs. First Quarter 2012	
(change in millions)	*(% change)*
$462.0	N/M

N/M - Not meaningful

In the first quarter 2013, an estimated probable loss on the Kemper IGCC of $462.0 million was recorded to reflect a revision of estimated costs expected to be incurred on the construction of the Kemper IGCC in excess of the $2.88 billion cost cap established by the Mississippi PSC, net of the DOE Grants and the Cost Cap Exceptions. See Note 3 to the financial statements of Mississippi Power under "Integrated Coal Gasification Combined Cycle" in Item 8 of the Form 10-K/A and FUTURE EARNINGS POTENTIAL – "Integrated Coal Gasification Combined Cycle" and Note (B) to the Condensed Financial Statements under "Integrated Coal Gasification Combined Cycle" herein for additional information.

Allowance for Equity Funds Used During Construction

First Quarter 2013 vs. First Quarter 2012	
(change in millions)	*(% change)*
$14.3	120.5

In the first quarter 2013, AFUDC equity was $26.1 million compared to $11.8 million for the corresponding period in 2012. The increase was primarily due to the construction of the Kemper IGCC.

See Note 3 to the financial statements of Mississippi Power under "Integrated Coal Gasification Combined Cycle" in Item 8 of the Form 10-K/A and FUTURE EARNINGS POTENTIAL – "Integrated Coal Gasification Combined Cycle" and Note (B) to the Condensed Financial Statements under "Integrated Coal Gasification Combined Cycle" herein for additional information regarding the Kemper IGCC.

Interest Expense, Net of Amounts Capitalized

First Quarter 2013 vs. First Quarter 2012	
(change in millions)	*(% change)*
$2.6	33.4

In the first quarter 2013, interest expense, net of amounts capitalized was $10.4 million compared to $7.8 million for the corresponding period in 2012. Capitalized interest primarily resulting from AFUDC debt associated with the Kemper IGCC in the first quarter 2013 was $11.1 million compared to $6.5 million for the corresponding period in 2012. The increase was primarily due to a $5.7 million increase in interest expense associated with issuances of new long-term debt in March 2012, August 2012, November 2012, January 2013, and March 2013 and a $3.0 million increase in interest expense resulting from the receipt of a $150 million deposit from SMEPA in March 2012 related to its pending purchase of an undivided interest in the Kemper IGCC. These increases were partially offset by a $4.6 million increase in capitalized interest primarily resulting from AFUDC debt associated with the Kemper IGCC and a $1.5 million decrease in interest expense associated with the redemption of long-term debt in 2012.

See Note 3 to the financial statements of Mississippi Power under "Integrated Coal Gasification Combined Cycle" in Item 8 of the Form 10-K/A and FUTURE EARNINGS POTENTIAL – "Integrated Coal Gasification Combined Cycle" and Note (B) to the Condensed Financial Statements under "Integrated Coal Gasification Combined Cycle" herein for additional information.

Income Taxes

First Quarter 2013 vs. First Quarter 2012	
(change in millions)	*(% change)*
$(177.5)	N/M

N/M - Not meaningful

In the first quarter 2013, income taxes were $(169.1) million compared to $8.4 million for the corresponding period in 2012. The decrease was due to the reduction in pre-tax earnings (loss) related to the estimated probable loss for the Kemper IGCC.

FUTURE EARNINGS POTENTIAL

The results of operations discussed above are not necessarily indicative of Mississippi Power's future earnings potential. The level of Mississippi Power's future earnings depends on numerous factors that affect the opportunities, challenges, and risks of Mississippi Power's business of selling electricity. These factors include Mississippi Power's ability to maintain a constructive regulatory environment that continues to allow for the timely recovery of prudently-incurred costs during a time of increasing costs and the successful completion of ongoing construction projects, including the Kemper IGCC. Future earnings in the near term will depend, in part, upon maintaining energy sales which is subject to a number of factors. These factors include weather, competition, new energy contracts with neighboring utilities, energy conservation practiced by customers, the price of electricity, the price elasticity of demand, and the rate of economic growth or decline in Mississippi Power's service territory. Changes in regional and global economic conditions may impact sales for Mississippi Power as the pace of the economic recovery remains uncertain. The timing and extent of the economic recovery will impact growth and may impact future earnings. For additional information relating to these issues, see RISK FACTORS in Item 1A and

MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL of Mississippi Power in Item 7 of the Form 10-K/A.

Environmental Matters

Compliance costs related to federal and state environmental statutes and regulations could affect earnings if such costs cannot continue to be fully recovered in rates on a timely basis. Environmental compliance spending over the next several years may differ materially from the amounts estimated. The timing, specific requirements, and estimated costs could change as environmental statutes and regulations are adopted or modified. Further, higher costs that are recovered through regulated rates could contribute to reduced demand for electricity, which could negatively affect results of operations, cash flows, and financial condition. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters" of Mississippi Power in Item 7 and Note 3 to the financial statements of Mississippi Power under "Environmental Matters" in Item 8 of the Form 10-K/A for additional information.

Environmental Statutes and Regulations

Air Quality

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations – Air Quality" of Mississippi Power in Item 7 of the Form 10-K/A for information regarding the EPA's MATS rule. On April 24, 2013, the EPA published a final reconsideration rule addressing new source standards within the MATS rule. Although the EPA had considered revisions to the startup and shutdown provisions of the MATS rule, a final decision on these provisions was deferred. The ultimate impact of this rulemaking will depend on the outcome of any additional rulemaking and/or legal challenges and, therefore, cannot be determined at this time.

Water Quality

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations – Water Quality" of Mississippi Power in Item 7 of the Form 10-K/A for additional information regarding the EPA's proposed revision of the current steam electric effluent guidelines. On April 19, 2013, the EPA signed a proposed rule which requests comments on a range of potential regulatory options for addressing certain wastestreams from steam electric power plants. These regulations could result in the installation of additional controls at certain of Mississippi Power's facilities, which could result in significant capital expenditures and compliance costs that could affect future unit retirement and replacement decisions. The ultimate impact of these proposed regulations will, however, depend on the specific requirements of the final rule and the outcome of any legal challenges and cannot be determined at this time.

FERC Matters

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "FERC Matters" and "Integrated Coal Gasification Combined Cycle" of Mississippi Power in Item 7 and Note 3 to the financial statements of Mississippi Power under "FERC Matters" and "Integrated Coal Gasification Combined Cycle" in Item 8 of the Form 10-K/A and Note (B) to the Condensed Financial Statement under "FERC Matters" herein for additional information.

In 2011, Mississippi Power filed a request with the FERC for an increase in wholesale base revenues under the Municipal and Rural Associations (MRA) cost-based electric tariff. In March 2012, Mississippi Power entered into a settlement agreement with its wholesale customers which provided that base revenues would increase by approximately $22.6 million over a 12-month period with revised rates effective for services rendered beginning April 1, 2012. In March 2012, the FERC approved a motion to place interim rates into effect beginning in May 2012. In September 2012, Mississippi Power, with its wholesale customers, filed a final settlement agreement with the FERC. In November 2012, the settlement judge certified the settlement agreement to the FERC with the recommendation that it be approved. The FERC has not yet approved the settlement agreement.

On April 1, 2013, Mississippi Power reached a settlement agreement with its wholesale customers and filed a request with the FERC for an additional increase in the MRA cost-based electric tariff. The 2013 settlement agreement provides that base rates under the MRA cost-based electric tariff will increase by approximately $24.2 million over a 12-month period, with revised rates effective for services rendered beginning April 1, 2013. If the 2013 settlement agreement is approved by the FERC, the amount of base rate revenues to be received in 2013 from the agreed upon increase will be approximately $18.0 million.

The ultimate outcome of these matters cannot be determined at this time.

PSC Matters

General

In August 2012, the Mississippi PSC issued an order for the purpose of investigating and reviewing for informational purposes only the ROE formulas used by Mississippi Power and all other regulated electric utilities in Mississippi. On March 14, 2013, the Mississippi Public Utilities Staff (MPUS) filed with the Mississippi PSC its report on the ROE formulas used by Mississippi Power and all other regulated electric utilities in Mississippi. The ultimate outcome of this matter cannot be determined at this time.

Performance Evaluation Plan

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "PSC Matters – Performance Evaluation Plan" of Mississippi Power in Item 7 and Note 3 to the financial statements of Mississippi Power under "Retail Regulatory Matters – Performance Evaluation Plan" in Item 8 of the Form 10-K/A for additional information regarding Mississippi Power's base rates.

On January 18, 2013, Mississippi Power filed its annual PEP filing for 2013, which indicated a rate increase of 1.990%, or $15.8 million, annually. On March 4, 2013, Mississippi Power and the MPUS filed a joint stipulation which revised the annual PEP filing for 2013 to reflect the removal of certain costs related to unresolved matters that are currently under review. On March 5, 2013 the revised annual PEP filing for 2013 was approved by the Mississippi PSC, which resulted in a rate increase of 1.925%, or $15.3 million, annually, with the new rates effective March 19, 2013. Mississippi Power may be entitled to $3.3 million in additional revenues in 2013 as a result of the late implementation of the 2013 PEP rate increase.

On March 15, 2013, Mississippi Power submitted its annual PEP lookback filing for 2012, which indicated a refund due to customers of $4.7 million, which was accrued in retail revenues. On May 1, 2013, the MPUS contested the filing.

The ultimate outcome of these matters cannot be determined at this time.

Environmental Compliance Overview Plan

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "PSC Matters – Environmental Compliance Overview Plan" of Mississippi Power in Item 7 and Note 3 to the financial statements of Mississippi Power under "Retail Regulatory Matters – Environmental Compliance Overview Plan" in Item 8 of the Form 10-K/A for information on Mississippi Power's annual environmental filing with the Mississippi PSC.

In April 2012, the Mississippi PSC approved Mississippi Power's request for a CPCN to construct a flue gas desulfurization system (scrubber) on Plant Daniel Units 1 and 2. In May 2012, the Sierra Club filed a notice of appeal of the order with the Chancery Court of Harrison County, Mississippi (Chancery Court). These units are jointly owned by Mississippi Power and Gulf Power, with 50% ownership each. The estimated total cost of the project is approximately $660 million, with Mississippi Power's portion being $330 million, excluding AFUDC. The project is scheduled for completion in December 2015. Mississippi Power's portion of the cost is expected to be recovered through the ECO Plan. As of March 31, 2013, total project expenditures were $183.2 million, with Mississippi Power's portion being $91.6 million. The ultimate outcome of this matter cannot be determined at this time.

Fuel Cost Recovery

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "PSC Matters – Fuel Cost Recovery" of Mississippi Power in Item 7 and Note 3 to the financial statements of Mississippi Power under "Retail Regulatory Matters – Fuel Cost Recovery" in Item 8 of the Form 10-K/A for information regarding Mississippi Power's fuel cost recovery.

On January 18, 2013, in compliance with Mississippi Power's filing requirement, Mississippi Power requested an annual adjustment of the retail fuel cost recovery factor in an amount equal to a decrease of 4.7%, or $35.5 million, of total 2012 retail revenue. The Mississippi PSC approved the retail fuel cost recovery factor on March 5, 2013, with the new rates effective March 19, 2013.

At March 31, 2013, the amount of over recovered retail fuel costs included on Mississippi Power's Condensed Balance Sheets herein was $60.9 million compared to $56.6 million at December 31, 2012. Mississippi Power also has wholesale MRA and Market Based (MB) fuel cost recovery factors. At March 31, 2013, the amount of over recovered wholesale MRA and MB fuel costs included on Mississippi Power's Condensed Balance Sheets herein was $18.1 million and $1.7 million, respectively, compared to $19.0 million and $2.1 million, respectively, at December 31, 2012. In addition, at each of March 31, 2013 and December 31, 2012, the amount of under recovered MRA emissions allowance cost included on Mississippi Power's Condensed Balance Sheets herein was $0.4 million. Mississippi Power's operating revenues are adjusted for differences in actual recoverable fuel cost and amounts billed in accordance with the currently approved cost recovery rate. Accordingly, changes in the billing factor have no significant effect on Mississippi Power's revenues or net income, but will affect cash flow.

Ad Valorem Tax Adjustment

On March 27, 2013, Mississippi Power filed its annual Ad Valorem Tax Adjustment factor filing for 2013, which requested an annual rate increase of 0.9%, or $7.1 million, due to an increase in ad valorem taxes resulting from the expiration of a tax exemption related to Plant Daniel Units 3 and 4.

The ultimate outcome of this matter cannot be determined at this time.

See RESULTS OF OPERATIONS – "Taxes Other Than Income Taxes" of Mississippi Power in Item 7 of the Form 10-K/A for additional information.

Storm Damage Cost Recovery

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "PSC Matters – Storm Damage Cost Recovery" of Mississippi Power in Item 7 and Note 3 to the financial statements of Mississippi Power under "Retail Regulatory Matters – Storm Damage Cost Recovery" in Item 8 in the Form 10-K/A for information regarding Mississippi Power's storm damage cost recovery. Mississippi Power maintains a reserve to cover the cost of damage from major storms to its transmission and distribution facilities and generally the cost of uninsured damage to its generation facilities and other property. At March 31, 2013, the balance in the storm reserve was $57.2 million.

Integrated Coal Gasification Combined Cycle

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Integrated Coal Gasification Combined Cycle" of Mississippi Power in Item 7 and Note 3 to the financial statements of Mississippi Power under "Integrated Coal Gasification Combined Cycle" in Item 8 of the Form 10-K/A for information regarding Mississippi Power's construction of the Kemper IGCC.

Kemper IGCC Project Approval

In 2010, the Mississippi PSC issued a CPCN authorizing the acquisition, construction, and operation of the Kemper IGCC (2010 MPSC Order) located in Kemper County, Mississippi. The Sierra Club filed an appeal of the Mississippi PSC's issuance of the CPCN and, in March 2012, the Mississippi Supreme Court reversed the decision of the Chancery Court upholding the 2010 MPSC Order and remanded the matter to the Mississippi PSC. The

Mississippi Supreme Court concluded that the 2010 MPSC Order did not cite in sufficient detail substantial evidence upon which the Mississippi Supreme Court could determine the basis for the findings of the Mississippi PSC granting the CPCN. In April 2012, the Mississippi PSC issued a detailed order (2012 MPSC Order) confirming the CPCN for the Kemper IGCC, which the Sierra Club appealed to the Chancery Court. In December 2012, the Chancery Court affirmed the 2012 MPSC Order which confirmed the issuance of the CPCN for the Kemper IGCC. On January 8, 2013, the Sierra Club filed an appeal of the Chancery Court's ruling with the Mississippi Supreme Court.

The Kemper IGCC is currently under construction and will utilize an integrated coal gasification combined cycle technology with an output capacity of 582 MWs. The Kemper IGCC will be fueled by locally mined lignite (an abundant, lower heating value coal) from a mine owned by Mississippi Power and situated adjacent to the Kemper IGCC that is scheduled to begin operations in June 2013. In connection with the Kemper IGCC, Mississippi Power also is constructing and plans to operate approximately 61 miles of CO_2 pipeline infrastructure. The Kemper IGCC and the CO_2 pipeline are scheduled to be placed in-service in May 2014. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Integrated Coal Gasification Combined Cycle – Lignite Mine and CO_2 Pipeline Facilities" of Mississippi Power in Item 7 and Note 3 to the financial statements of Mississippi Power under "Integrated Coal Gasification Combined Cycle – Lignite Mine and CO_2 Pipeline Facilities" in Item 8 of the Form 10-K/A for additional information regarding the lignite mine and the CO_2 pipeline.

The ultimate outcome of the CPCN challenge cannot be determined at this time.

Kemper IGCC Cost Estimate

The certificated cost estimate of the Kemper IGCC included in the 2012 MPSC Order was $2.4 billion, net of $245 million of DOE Grants, the cost of the lignite mine and equipment, the cost of the CO_2 pipeline facilities, and AFUDC related to the Kemper IGCC. The 2012 MPSC Order approved a construction cost cap of up to $2.88 billion, with recovery of prudently-incurred costs subject to approval by the Mississippi PSC. Exceptions to the $2.88 billion cost cap include the cost of the lignite mine and equipment, the cost of the CO_2 pipeline facilities, AFUDC, and certain general exceptions as contemplated in the Settlement Agreement (described below) and the 2012 MPSC Order, which includes change of law, force majeure, and beneficial capital (which exists when Mississippi Power demonstrates that the purpose and effect of the construction cost increase is to produce efficiencies that will result in a neutral or favorable effect on customers, relative to the original proposal for the CPCN) (Cost Cap Exceptions). Recovery of the Cost Cap Exception amounts remains subject to review and approval by the Mississippi PSC.

On April 23, 2013, Mississippi Power revised its cost estimate for the Kemper IGCC to approximately $3.42 billion, net of the DOE Grants and the Cost Cap Exceptions. Estimated amounts of the Cost Cap Exceptions include $245 million for the lignite mine and equipment, $132 million for the CO_2 pipeline facilities, $324 million of AFUDC, and $102 million of other general exceptions. The revised cost estimate reflects additional cost pressures, including labor costs, piping and other material costs, engineering and support costs, and productivity decreases. Mississippi Power does not intend to seek any joint owner contributions or rate recovery for any costs of the Kemper IGCC that exceed the $2.88 billion cost cap, except for amounts subject to the Cost Cap Exceptions. Accordingly, Mississippi Power reflected a pre-tax charge to income for this estimated probable loss of $462.0 million ($285.3 million after tax) in the first quarter 2013. See RESULTS OF OPERATIONS – "Estimated Loss on Kemper IGCC."

Mississippi Power's analysis of the estimated cost to complete the Kemper IGCC will be ongoing throughout the construction period. It is possible that Mississippi Power could experience further cost increases and/or schedule delays with respect to the Kemper IGCC as a result of factors including, but not limited to, costs and productivity of labor, adverse weather conditions, shortages and inconsistent quality of equipment, materials, and labor, contractor or supplier delay or non-performance under construction or other agreements, delays associated with start-up activities, and/or unforeseen engineering problems. In subsequent periods, any changes in the estimated costs to complete construction of the Kemper IGCC subject to the $2.88 billion cost cap will be reflected in Mississippi Power's statements of income and these changes could be material.

As of March 31, 2013, Mississippi Power had spent a total of $2.88 billion on the Kemper IGCC, excluding the estimated probable loss. These costs include $2.41 billion for the portion of the Kemper IGCC subject to the construction cost cap, $188.9 million for the lignite mine and equipment, $84.4 million for the CO_2 pipeline facilities, $156.4 million of AFUDC, and $43.1 million of other costs, including certain general exceptions and certain regulatory assets. Of this total, $2.29 billion was included in CWIP (which is net of the DOE Grants and an estimated probable loss of $540 million), $43.4 million in other regulatory assets, $3.8 million in other deferred charges and assets on Mississippi Power's Condensed Balance Sheet herein, and $1.0 million was previously expensed. Consistent with the treatment of non-capital costs incurred during the pre-construction period, the Mississippi PSC granted Mississippi Power the authority to defer all non-capital Kemper IGCC-related costs to a regulatory asset during the construction period. This includes deferred costs associated with the generation resource planning, evaluation, and screening activities. The amortization period for the regulatory asset will be determined by the Mississippi PSC at a later date. In addition, Mississippi Power is authorized to accrue carrying costs on the unamortized balance of such regulatory assets at a rate and in a manner to be determined by the Mississippi PSC in future cost recovery mechanism proceedings.

The ultimate outcome of these matters cannot be determined at this time.

Rate Recovery of Kemper IGCC Costs

See "FERC Matters" for additional information regarding Mississippi Power's MRA cost-based tariff relating to recovery of a portion of the Kemper IGCC costs from Mississippi Power's wholesale customers. Rate recovery of the retail portion of the Kemper IGCC is subject to the jurisdiction of the Mississippi PSC. See "Baseload Act" herein for additional information.

On January 24, 2013, Mississippi Power entered into a settlement agreement (Settlement Agreement) with the Mississippi PSC that, among other things, establishes the process for resolving matters regarding cost recovery related to the Kemper IGCC. Under the Settlement Agreement, Mississippi Power agreed to limit the portion of prudently-incurred Kemper IGCC costs to be included in retail rate base to the $2.4 billion certificated cost estimate, plus the Cost Cap Exceptions as well as any other costs permitted or determined to be excluded from the $2.88 billion cost cap by the Mississippi PSC. Mississippi Power intends to finance (1) prudently-incurred costs in excess of the certificated cost estimate and up to the $2.88 billion cost cap, net of the DOE Grants and the Cost Cap Exceptions, (2) the accrued AFUDC, and (3) exceptions not provided for in the Seven-Year Rate Plan (discussed below) through securitization as provided in State of Mississippi legislation. The rate recovery necessary to recover the annual costs of securitization is expected to be filed and become effective after the Kemper IGCC is placed in service and following completion of the Mississippi PSC's final prudence review of costs for the Kemper IGCC.

Under the terms of the Settlement Agreement, Mississippi Power and the Mississippi PSC agreed to follow certain regulatory procedures and schedules for resolving the cost recovery matters related to the Kemper IGCC. These procedures and schedules include the following: (1) Mississippi Power's filing on January 25, 2013 of a new request to increase retail rates in 2013 by $172 million annually, based on projected investment for 2013, to be recorded to a regulatory liability to be used to mitigate rate impacts when the Kemper IGCC is placed in service; (2) the Mississippi PSC's decision on that matter on March 5, 2013 as described below; (3) Mississippi Power's collaboration with the MPUS to file with the Mississippi PSC within three months of the Settlement Agreement a rate recovery plan for the Kemper IGCC for the first seven years of its operation, along with a proposed revenue requirement under such plan for 2014 through 2020 (Seven-Year Rate Plan) (which was made on February 26, 2013 and updated on March 22, 2013 as described below); (4) the Mississippi PSC's decision on the Seven-Year Rate Plan within four months of that filing (which is now expected to occur in the fall of 2013); (5) Mississippi Power's agreement to limit the portion of prudently-incurred Kemper IGCC costs to be included in rate base to the $2.4 billion certificated cost estimate, plus the Cost Cap Exceptions, excluding AFUDC, provided that this limitation will not prevent Mississippi Power from securing alternate financing to recover any prudently-incurred Kemper IGCC costs, including plant costs above the $2.4 billion certificated cost estimate and AFUDC, not otherwise recovered in any Mississippi PSC rate proceeding contemplated by the Settlement Agreement; and (6) the Mississippi PSC's completion of its prudence review of the Kemper IGCC costs incurred through 2012 within six

months of the Settlement Agreement, an additional prudence review upon considering the Seven-Year Rate Plan for costs incurred through the most recent reporting period, and a final prudence review of the remaining project costs within six months of the Kemper IGCC's in-service date. The Settlement Agreement provides that Mississippi Power may terminate the agreement if certain conditions are not met, if Mississippi Power is unable to secure alternate financing for any prudently-incurred Kemper IGCC costs not otherwise recovered in any Mississippi PSC rate proceeding contemplated by the Settlement Agreement, or if the Mississippi PSC fails to comply with the requirements of the Settlement Agreement. Legislation to authorize a multi-year rate plan and legislation to provide for alternate financing through securitization was enacted into law on February 26, 2013. Mississippi Power is currently working with the Mississippi PSC and the MPUS to implement the procedural schedules set forth in the Settlement Agreement and variations to the schedule are likely.

On March 5, 2013, the Mississippi PSC issued an order (2013 Kemper IGCC Order) approving a 15% increase in retail rates effective on March 19, 2013, and an additional 3% increase in retail rates effective January 1, 2014, which collectively are designed to collect $156 million annually beginning in 2014. All amounts collected through April 2014, which are expected to total $126 million, will be recorded as a regulatory liability to be used to mitigate rate impacts beginning in May 2014 when the Kemper IGCC is expected to be placed in service. On March 21, 2013, a legal challenge to the 2013 Kemper IGCC Order was filed with the Mississippi Supreme Court.

Because the 2013 Kemper IGCC Order did not provide for the inclusion of CWIP in rate base as permitted by the Baseload Act described below, Mississippi Power continues to record AFUDC on the Kemper IGCC during the construction period. Mississippi Power will not record AFUDC on any additional costs of the Kemper IGCC that exceed the $2.88 billion cost cap, except for Cost Cap Exception amounts. Mississippi Power's rate plans filed pursuant to the Settlement Agreement contemplate the continued accrual of AFUDC through the May 2014 expected in-service date.

On March 22, 2013, Mississippi Power, in compliance with the 2013 Kemper IGCC Order, filed a revision to the Seven-Year Rate Plan with the Mississippi PSC for the Kemper IGCC for 2014 through 2020, the first seven years of operation of the Kemper IGCC. The Seven-Year Rate Plan, which contemplates Mississippi Power's sale of a 15% undivided ownership interest in the Kemper IGCC, proposes recovery of an annual revenue requirement of approximately $156 million of Kemper IGCC-related operational costs and rate base amounts, including plant costs equal to the $2.4 billion certificated cost estimate. The 2013 Kemper IGCC Order, which increased rates beginning on March 19, 2013, is integral to the Seven-Year Rate Plan, which contemplates amortization of the April 2014 regulatory liability balance to be used to mitigate rate impacts from the expected in-service date of May 2014 through 2020, based on a fixed amortization schedule that requires approval by the Mississippi PSC. Under the Seven-Year Rate Plan filing, Mississippi Power proposes annual rate recovery to remain the same from 2014 through 2020. While it is the intent of Mississippi Power for the actual revenue requirement to equal the proposed revenue requirement, Mississippi Power proposes that the annual differences through 2020 for certain items contemplated in the Seven-Year Rate Plan will be deferred, subject to accrual of carrying costs, and the cumulative balance will be reviewed at the end of the term of the Settlement Agreement by the Mississippi PSC to determine the disposition of any potential remaining deferred balance.

The revenue requirements set forth in Mississippi Power's Seven-Year Rate Plan described above assume, among other things, the Kemper IGCC will be placed in service in May 2014, the sale of a 15% undivided interest in the Kemper IGCC to SMEPA will be completed as described herein, Mississippi Power's receipt of the benefits relating to tax credits described herein, and recovery of the Cost Cap Exceptions described herein.

The ultimate outcome of these matters, including the determinations of prudency and the specific manner of recovery of costs relating to the Kemper IGCC, is subject to further regulatory actions and cannot be determined at this time.

Proposed Sale of Undivided Interest to SMEPA

In 2010, Mississippi Power and SMEPA entered into an asset purchase agreement whereby SMEPA agreed to purchase a 17.5% undivided interest in the Kemper IGCC. In February 2012, the Mississippi PSC approved the sale

and transfer of 17.5% of the Kemper IGCC to SMEPA. In June 2012, Mississippi Power and SMEPA signed an amendment to the asset purchase agreement whereby SMEPA extended its option to purchase until December 31, 2012, and reduced its purchase commitment percentage from a 17.5% to a 15% undivided interest in the Kemper IGCC, subject to approval by the Mississippi PSC. On December 31, 2012, Mississippi Power and SMEPA agreed to extend SMEPA's option to purchase through December 31, 2013.

The closing of this transaction is conditioned upon execution of a joint ownership and operating agreement, receipt of all construction permits, appropriate regulatory approvals, financing, and other conditions. In September 2012, SMEPA received a conditional loan commitment from Rural Utilities Service to provide funding for SMEPA's undivided interest in the Kemper IGCC.

In March 2012, Mississippi Power received a $150 million interest-bearing refundable deposit from SMEPA to be applied to the purchase. While the expectation is that the amount will be applied to the purchase price at closing, Mississippi Power would be required to refund the deposit upon the termination of the asset purchase agreement, within 60 days of a request by SMEPA for a full or partial refund, or within 15 days at SMEPA's discretion in the event that Mississippi Power is assigned a senior unsecured credit rating of BBB+ or lower by S&P or Baa1 or lower by Moody's or ceases to be rated by either of these rating agencies. Given the interest-bearing nature of the deposit and SMEPA's ability to request a refund, the deposit has been presented as a current liability in Mississippi Power's Condensed Balance Sheets herein and as financing proceeds in Mississippi Power's Condensed Statements of Cash Flows herein.

The ultimate outcome of these matters cannot be determined at this time.

Baseload Act

In 2008, the Baseload Act was signed by the Governor of Mississippi and is designed to enhance the Mississippi PSC's authority to facilitate development and construction of base load generation in the State of Mississippi. The Baseload Act authorizes, but does not require, the Mississippi PSC to adopt a cost recovery mechanism that includes in retail base rates, prior to and during construction, all or a portion of the prudently-incurred pre-construction and construction costs incurred by a utility in constructing a base load electric generating plant. Prior to the passage of the Baseload Act, such costs would traditionally be recovered only after the plant was placed in service. The Baseload Act also provides for periodic prudence reviews by the Mississippi PSC and prohibits the cancellation of any such generating plant without the approval of the Mississippi PSC. In the event of cancellation of the construction of the plant without approval of the Mississippi PSC, the Baseload Act authorizes the Mississippi PSC to make a public interest determination as to whether and to what extent the utility will be afforded rate recovery for costs incurred in connection with such cancelled generating plant. There are legal challenges to the constitutionality of the Baseload Act currently pending before the Mississippi Supreme Court. The ultimate outcome of the legal challenges to this legislation cannot be determined at this time. See "Rate Recovery of Kemper IGCC Costs" herein for additional information.

Tax Incentives

The IRS has allocated $133 million (Phase I) and $279 million (Phase II) of Internal Revenue Code Section 48A tax credits to Mississippi Power in connection with the Kemper IGCC. Mississippi Power's utilization of Phase I and Phase II credits is dependent upon meeting the IRS certification requirements, including an in-service date no later than May 11, 2014 for the Phase I credits and April 19, 2016 for the Phase II credits. In order to remain eligible for the Phase II credits, Mississippi Power plans to capture and sequester (via enhanced oil recovery) at least 65% of the CO_2 produced by the Kemper IGCC during operations in accordance with the rules for Section 48A investment tax credits. Through March 31, 2013, Mississippi Power had received or accrued tax benefits totaling $412 million for these tax credits, which will be amortized as a reduction to depreciation and amortization over the life of the Kemper IGCC. As a result of bonus tax depreciation on certain assets placed, or to be placed, in service in 2012 and 2013, and the subsequent reduction in federal taxable income, Mississippi Power estimates that it will not be able to utilize $178.8 million of these tax credits until after March 31, 2014. IRS guidelines allow these unused tax credits to be carried forward for 20 years from the date received, if not utilized before then. In October 2012, Mississippi

Power filed an application with the DOE for certification of the Kemper IGCC for additional tax credits under the Internal Revenue Code Section 48A (Phase III).

A portion of the tax credits realized by Mississippi Power may be subject to recapture upon successful completion of SMEPA's purchase of an undivided interest in the Kemper IGCC as described above. In addition, all or a portion of the tax credits will be subject to recapture if Mississippi Power fails to satisfy the in-service date requirements and CO_2 capture requirements described above.

On January 2, 2013, the American Taxpayer Relief Act of 2012 (ATRA) was signed into law. The ATRA retroactively extended several tax credits through 2013 and 50% bonus depreciation for property to be placed in service in 2013 (and for certain long-term production-period projects to be placed in service in 2014), which is expected to apply to the Kemper IGCC.

The ultimate outcome of these matters cannot be determined at this time.

Other Matters

Mississippi Power is involved in various other matters being litigated and regulatory matters that could affect future earnings. In addition, Mississippi Power is subject to certain claims and legal actions arising in the ordinary course of business. Mississippi Power's business activities are subject to extensive governmental regulation related to public health and the environment, such as regulation of air emissions and water discharges. Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements, such as air quality and water standards, has increased generally throughout the U.S. In particular, personal injury, property damage, and other claims for damages alleged to have been caused by CO_2 and other emissions, coal combustion byproducts, and alleged exposure to hazardous materials, and/or requests for injunctive relief in connection with such matters, have become more frequent. The ultimate outcome of such pending or potential litigation against Mississippi Power cannot be predicted at this time; however, for current proceedings not specifically reported in Note (B) to the Condensed Financial Statements herein or in Note 3 to the financial statements of Mississippi Power in Item 8 of the Form 10-K/A, management does not anticipate that the ultimate liabilities, if any, arising from such current proceedings would have a material effect on Mississippi Power's financial statements.

See the Notes to the Condensed Financial Statements herein for a discussion of various other contingencies, regulatory matters, and other matters being litigated which may affect future earnings potential.

ACCOUNTING POLICIES

Application of Critical Accounting Policies and Estimates

Mississippi Power prepares its financial statements in accordance with GAAP. Significant accounting policies are described in Note 1 to the financial statements of Mississippi Power in Item 8 of the Form 10-K/A. In the application of these policies, certain estimates are made that may have a material impact on Mississippi Power's results of operations and related disclosures. Different assumptions and measurements could produce estimates that are significantly different from those recorded in the financial statements. See MANAGEMENT'S DISCUSSION AND ANALYSIS – ACCOUNTING POLICIES – "Application of Critical Accounting Policies and Estimates" of Mississippi Power in Item 7 of the Form 10-K/A for a complete discussion of Mississippi Power's critical accounting policies and estimates related to Electric Utility Regulation, Contingent Obligations, Unbilled Revenues, Pension and Other Postretirement Benefits, and AFUDC.

Estimated Construction Costs for the Kemper IGCC

Subsequent to the filing of Mississippi Power's Annual Report on Form 10-K for the year ended December 31, 2012, Mississippi Power revised its cost estimate to complete construction of the Kemper IGCC to an amount that exceeds the $2.88 billion cost cap, net of the DOE Grants and the Cost Cap Exceptions. Mississippi Power does not intend to seek any joint owner contributions or rate recovery for any Kemper IGCC construction costs that exceed

the $2.88 billion cost cap, except for amounts subject to the Cost Cap Exceptions and net of the DOE Grants. As a result, Mississippi Power recorded a pretax charge of $78 million and $462 million in 2012 and the first quarter 2013, respectively. In subsequent periods, any changes in the estimated costs to complete construction of the Kemper IGCC subject to the $2.88 billion cost cap will be reflected in Mississippi Power's statements of income and these changes could be material. Mississippi Power's analysis will be ongoing throughout the construction period. It is possible that Mississippi Power could experience further cost increases and/or schedule delays with respect to the Kemper IGCC as a result of factors including, but not limited to, costs and productivity of labor, adverse weather conditions, shortages and inconsistent quality of equipment, materials, and labor, contractor or supplier delay or non-performance under construction or other agreements, delays associated with start-up activities, and/or unforeseen engineering problems. Given the significant judgment involved in estimating the future costs to complete construction, schedule, and the ultimate rate recoverability for the Kemper IGCC, schedule, and ultimate recoverability for the Kemper IGCC, and the potential impact on Mississippi Power's results of operations, Mississippi Power considers the future total construction costs for the Kemper IGCC to be a critical accounting estimate. See FUTURE EARNINGS POTENTIAL – "Integrated Coal Gasification Combined Cycle" of Mississippi Power in Item 7 and Note 3 to the financial statements of Mississippi Power under "Integrated Coal Gasification Combined Cycle" in Item 8 of the Form 10-K/A and FUTURE EARNINGS POTENTIAL – "Integrated Coal Gasification Combined Cycle" and Note (B) to the Condensed Financial Statements under "Integrated Coal Gasification Combined Cycle" herein for additional information.

FINANCIAL CONDITION AND LIQUIDITY

Overview

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FINANCIAL CONDITION AND LIQUIDITY – "Overview" of Mississippi Power in Item 7 of the Form 10-K/A for additional information. Mississippi Power's financial condition remained stable at March 31, 2013. Mississippi Power intends to continue to monitor its access to short-term and long-term capital markets as well as its bank credit arrangements to meet future capital and liquidity needs. See "Sources of Capital," "Financing Activities," and "Capital Requirements and Contractual Obligations" herein for additional information.

Net cash used for operating activities totaled $25.2 million for the first three months of 2013, a decrease of $25.8 million as compared to the corresponding period in 2012. The decrease in cash provided from operating activities is primarily due to a decrease in investment tax credits related to the Kemper IGCC, a decrease in accounts receivable, a decrease in accrued taxes, and a decrease in regulatory clause revenues due to an increase in fuel costs, partially offset by an increase in fossil fuel stock and an increase due to hedges settled in 2012. Net cash used for investing activities totaled $352.4 million for the first three months of 2013 primarily due to gross property additions related to the Kemper IGCC. Net cash provided from financing activities totaled $420.3 million for the first three months of 2013 primarily due to the issuances of bank notes and capital contributions from Southern Company. Fluctuations in cash flow from financing activities vary year to year based on capital needs and the maturity or redemption of securities.

Significant balance sheet changes for the first three months of 2013 include a decrease in total property, plant, and equipment of $84.5 million, a decrease in accumulated deferred income taxes of $164.3 million, and a decrease in total common stockholder's equity of $189.0 million primarily due to the estimated probable loss on the Kemper IGCC. The decrease in retained earnings was partially offset by an increase in paid-in capital of $101.3 million primarily due to $100.0 million of capital contributions from Southern Company. Securities due within one year and long-term debt increased $370.4 million primarily due to the issuance of $350.0 million of bank notes and $15.8 million of revenue bonds. Prepaid income taxes and accumulated deferred investment tax credits increased $44.0 million and $50.1 million, respectively, primarily due to the Kemper IGCC investment tax credit. Other accrued taxes decreased $47.4 million primarily due to the payment of ad valorem taxes.

Capital Requirements and Contractual Obligations

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FINANCIAL CONDITION AND LIQUIDITY –"Capital Requirements and Contractual Obligations" of Mississippi Power in Item 7 of the Form 10-K/A for a description of Mississippi Power's capital requirements for its construction program, including estimated capital expenditures for new generating resources and to comply with existing environmental statutes and regulations, scheduled maturities of long-term debt, as well as related interest, leases, purchase commitments, derivative obligations, preferred stock dividends, trust funding requirements, and unrecognized tax benefits. See FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations" herein for additional information. Approximately $342.3 million will be required through March 31, 2014 to fund maturities of long-term debt.

See FUTURE EARNINGS POTENTIAL – "Integrated Coal Gasification Combined Cycle" and Note (B) to the Condensed Financial Statements under "Integrated Coal Gasification Combined Cycle" herein for information on the construction of the Kemper IGCC. The construction program of Mississippi Power is currently estimated to include a base level investment of $1.2 billion, $638 million, and $255 million for 2013, 2014, and 2015, respectively. Included in these estimated amounts are expenditures related to construction of the Kemper IGCC of $913 million and $358 million in 2013 and 2014, respectively, which are net of SMEPA's 15% proposed ownership share of the Kemper IGCC, which reflects costs of approximately $492 million and $28 million in 2013 and 2014, respectively. The estimated share for SMEPA in 2013 reflects estimated construction costs relating to SMEPA's proposed ownership interest to be incurred through December 31, 2013 (including construction costs for all prior years relating to its proposed ownership interest).

The construction program is subject to periodic review and revision, and actual construction costs may vary from these estimates because of numerous factors. These factors include: changes in business conditions; changes in load projections; storm impacts; changes in environmental statutes and regulations; the outcome of any legal challenges to environmental rules; changes in generating plants, including unit retirements and replacements and adding or changing fuel sources at existing units, to meet regulatory requirements; changes in FERC rules and regulations; Mississippi PSC approvals; changes in the expected environment compliance programs; changes in legislation; the cost and efficiency of construction labor, equipment, and materials; project scope and design changes; and the cost of capital. See FUTURE EARNINGS POTENTIAL – "Integrated Coal Gasification Combined Cycle – Kemper IGCC Cost Estimate" and Note (B) to the Condensed Financial Statements under "Integrated Coal Gasification Combined Cycle – Kemper IGCC Cost Estimate" herein for a discussion of factors that may impact the projected cost and/or schedule of the Kemper IGCC. In addition, there can be no assurance that costs related to capital expenditures will be fully recovered.

Sources of Capital

Except as described herein, Mississippi Power plans to obtain the funds required for construction and other purposes from sources similar to those used in the past, which were primarily funds from operating cash flows, security issuances, term loans, short-term debt, and equity contributions from Southern Company. However, the amount, type, and timing of any future financings, if needed, will depend upon regulatory approval, prevailing market conditions, and other factors. In January 2013, Mississippi Power received $100 million in capital contributions from Southern Company. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FINANCIAL CONDITION AND LIQUIDITY – "Sources of Capital" of Mississippi Power in Item 7 of the Form 10-K/A for additional information.

Mississippi Power has received $245.3 million in DOE CCPI2 grant funds that have been used for the construction of the Kemper IGCC. An additional $25 million in CCPI2 grant funds is expected to be received for the initial operation of the Kemper IGCC. See Note (B) to the Condensed Financial Statements under "Integrated Coal Gasification Combined Cycle" herein for information regarding legislation related to the securitization of certain costs of the Kemper IGCC.

Mississippi Power's current liabilities frequently exceed current assets because of the continued use of short-term obligations as a funding source to meet scheduled maturities of long-term debt, as well as cash needs, which can fluctuate significantly due to the seasonality of the business.

At March 31, 2013, Mississippi Power had approximately $187.8 million of cash and cash equivalents. Committed credit arrangements with banks at March 31, 2013 were as follows:

Expires[a]					Executable Term Loans		Due Within One Year	
2013	2014	2016	Total	Unused	One Year	Two Years	Term Out	No Term Out
(in millions)			*(in millions)*		*(in millions)*		*(in millions)*	
$ 110	$ 25	$ 165	$ 300	$ 300	$ 25	$ 40	$ 65	$ 70

(a) No credit arrangements expire in 2015.

See Note 6 to the financial statements of Mississippi Power under "Bank Credit Arrangements" in Item 8 of the Form 10-K/A and Note (E) to the Condensed Financial Statements under "Bank Credit Arrangements" herein for additional information.

These credit arrangements provide liquidity support to Mississippi Power's commercial paper borrowings and variable rate pollution control revenue bonds. The amount of variable rate pollution control revenue bonds outstanding requiring liquidity support as of March 31, 2013 was approximately $40 million.

In March 2013, Mississippi Power amended certain of its credit arrangements, which extended the maturity dates from 2014 to 2016 and revised the definition of debt to exclude securitized debt relating to the Kemper IGCC for purposes of calculating the debt covenant under these credit arrangements. See Note (B) to the Condensed Financial Statements under "Integrated Coal Gasification Combined Cycle" herein for information regarding legislation related to the securitization of certain costs of the Kemper IGCC.

Most of these arrangements contain covenants that limit debt levels and typically contain cross default provisions that are restricted only to the indebtedness of Mississippi Power. Mississippi Power is currently in compliance with all such covenants. Mississippi Power expects to renew its credit arrangements, as needed, prior to expiration.

Mississippi Power may also meet short-term cash needs through a Southern Company subsidiary organized to issue and sell commercial paper at the request and for the benefit of Mississippi Power and the other traditional operating companies. Proceeds from such issuances for the benefit of Mississippi Power are loaned directly to Mississippi Power. The obligations of each company under these arrangements are several and there is no cross affiliate credit support.

Details of short-term borrowings were as follows:

	Short-term Debt at March 31, 2013		Short-term Debt During the Period[a]		
	Amount Outstanding	Weighted Average Interest Rate	Average Outstanding	Weighted Average Interest Rate	Maximum Amount Outstanding
	(in millions)		*(in millions)*		*(in millions)*
Commercial paper	$ —	—%	$ 15	0.2%	$ 139

(a) Average and maximum amounts are based upon daily balances during the three-month period ended March 31, 2013.

Management believes that the need for working capital can be adequately met by utilizing commercial paper, lines of credit, and cash.

Credit Rating Risk

Mississippi Power does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. There are certain contracts that could require collateral, but not accelerated payment, in the event of a credit rating change to below BBB- and/or Baa3. These contracts are for physical electricity sales, fuel purchases, fuel transportation and storage, emissions allowances, and energy price risk management. At March 31, 2013, the maximum potential collateral requirements under these contracts at a rating below BBB- and/or Baa3 were approximately $268 million. Included in these amounts are certain agreements that could require collateral in the event that one or more Power Pool participant has a credit rating change to below investment grade. Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash.

In March 2012, Mississippi Power received a $150 million interest-bearing refundable deposit from SMEPA to be applied to the sale price for the pending sale of an undivided interest in the Kemper IGCC. Until the acquisition is closed, the deposit bears interest at Mississippi Power's AFUDC rate adjusted for income taxes, which was 9.967% per annum for 2012 and 9.962% per annum at March 31, 2013, and is refundable to SMEPA upon termination of the asset purchase agreement related to such purchase, within 60 days of a request by SMEPA for a full or partial refund, or within 15 days at SMEPA's discretion in the event that Mississippi Power is assigned a senior unsecured credit rating of BBB+ or lower by S&P or Baa1 or lower by Moody's or ceases to be rated by either of these rating agencies.

Market Price Risk

Mississippi Power's market risk exposure relative to interest rate changes for the first quarter 2013 has not changed materially compared with the December 31, 2012 reporting period. Since a significant portion of outstanding indebtedness is at fixed rates, Mississippi Power is not aware of any facts or circumstances that would significantly affect exposures on existing indebtedness in the near term. However, the impact on future financing costs cannot now be determined.

Due to cost-based rate regulation and other various cost recovery mechanisms, Mississippi Power continues to have limited exposure to market volatility in interest rates, foreign currency exchange rates, commodity fuel prices, and prices of electricity. To mitigate residual risks relative to movements in electricity prices, Mississippi Power enters into physical fixed-price contracts for the purchase and sale of electricity through the wholesale electricity market. Mississippi Power continues to manage retail fuel-hedging programs implemented per the guidelines of the Mississippi PSC and wholesale fuel-hedging programs under agreements with wholesale customers. As a result, Mississippi Power had no material change in market risk exposure for the first quarter 2013 when compared with the December 31, 2012 reporting period.

The changes in fair value of energy-related derivative contracts, substantially all of which are composed of regulatory hedges, for the three months ended March 31, 2013 were as follows:

	First Quarter 2013 Changes
	Fair Value
	(in millions)
Contracts outstanding at the beginning of the period, assets (liabilities), net	$ (17)
Contracts realized or settled	4
Current period changes[(a)]	8
Contracts outstanding at the end of the period, assets (liabilities), net	$ (5)

(a) Current period changes also include the changes in fair value of new contracts entered into during the period, if any.

The changes in the fair value positions of the energy-related derivative contracts, which are substantially all attributable to both the volume and the price of natural gas, for the three ended March 31, 2013 were as follows:

	First Quarter 2013 Changes
	Fair Value
	(in millions)
Natural gas swaps	$ 12
Natural gas options	—
Total changes	$ 12

The net hedge volumes of energy-related derivative contracts were as follows:

	March 31, 2013	December 31, 2012
	mmBtu Volume	
	(in millions)	
Commodity – Natural gas swaps	**36**	38
Commodity – Natural gas options	—	—
Total hedge volume	**36**	38

The weighted average swap contract cost above market prices was approximately $0.13 per mmBtu as of March 31, 2013 and $0.44 per mmBtu as of December 31, 2012. The change in option fair value is primarily attributable to the volatility of the market and the underlying change in the natural gas price. The costs associated with natural gas hedges are recovered through Mississippi Power's energy cost management clauses (ECM).

At March 31, 2013 and December 31, 2012, substantially all of Mississippi Power's energy-related derivative contracts were designated as regulatory hedges and are related to Mississippi Power's fuel-hedging program. Therefore, gains and losses are initially recorded as regulatory liabilities and assets, respectively, and then are included in fuel expense as they are recovered through the ECM.

Unrealized pre-tax gains and losses recognized in income for the three months ended March 31, 2013 and 2012 for energy-related derivative contracts that are not hedges were not material.

Mississippi Power uses over-the-counter contracts that are not exchange traded but are fair valued using prices which are market observable, and thus fall into Level 2. See Note (C) to the Condensed Financial Statements herein for further discussion on fair value measurements. The maturities of the energy-related derivative contracts, which are all Level 2 of the fair value hierarchy, at March 31, 2013 were as follows:

	March 31, 2013 Fair Value Measurements			
	Total	Maturity		
	Fair Value	Year 1	Years 2&3	Years 4&5
		(in millions)		
Level 1	$ —	$ —	$ —	$ —
Level 2	(5)	(3)	(2)	—
Level 3	—	—	—	—
Fair value of contracts outstanding at end of period	$ (5)	$ (3)	$ (2)	$ —

For additional information, see MANAGEMENT'S DISCUSSION AND ANALYSIS – FINANCIAL CONDITION AND LIQUIDITY – "Market Price Risk" of Mississippi Power in Item 7 and Note 1 under "Financial Instruments"

and Note 10 to the financial statements of Mississippi Power in Item 8 of the Form 10-K/A and Note (H) to the Condensed Financial Statements herein.

Financing Activities

In November 2012, Mississippi Power entered into a 366-day $100 million aggregate principal amount floating rate bank loan bearing interest based on one-month LIBOR. The first advance in the amount of $50 million was made in November 2012. In January 2013, the second advance in the amount of $50 million was made. The proceeds of the loan were used for working capital and for other general corporate purposes, including Mississippi Power's continuous construction program.

In March 2013, Mississippi Power entered into four two-year floating rate bank loans bearing interest based on one-month LIBOR. These term loans were for $50 million, $75 million, $75 million, and $100 million aggregate principal amounts, and proceeds were used for working capital and other general corporate purposes, including Mississippi Power's continuous construction program.

In March 2013, the Mississippi Business Finance Corporation (MBFC) issued $15.8 million aggregate principal amount of MBFC Taxable Revenue Bonds (Mississippi Power Company Project), Series 2012A. The proceeds were used to reimburse Mississippi Power for the cost of the acquisition, construction, equipping, installation, and improvement of certain equipment and facilities for the lignite mining facility related to the Kemper IGCC. Any future issuances of the Series 2012A bonds will be used for this same purpose. See Note 6 to the financial statements of Mississippi Power under "Other Revenue Bonds" in Item 8 of the Form 10-K/A for additional information.

In addition to any financings that may be necessary to meet capital requirements and contractual obligations, Mississippi Power plans to continue, when economically feasible, a program to retire higher-cost securities and replace these obligations with lower-cost capital if market conditions permit.

SOUTHERN POWER COMPANY
AND SUBSIDIARY COMPANIES

SOUTHERN POWER COMPANY AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME (UNAUDITED)

	For the Three Months Ended March 31,	
	2013	2012
	(in thousands)	
Operating Revenues:		
Wholesale revenues, non-affiliates	**$ 223,429**	$ 140,557
Wholesale revenues, affiliates	**78,191**	111,788
Other revenues	**1,327**	1,336
Total operating revenues	**302,947**	253,681
Operating Expenses:		
Fuel	**119,372**	89,078
Purchased power, non-affiliates	**14,573**	20,650
Purchased power, affiliates	**7,865**	2,340
Other operations and maintenance	**50,950**	48,389
Depreciation and amortization	**40,160**	31,913
Taxes other than income taxes	**5,354**	4,968
Total operating expenses	**238,274**	197,338
Operating Income	**64,673**	56,343
Other Income and (Expense):		
Interest expense, net of amounts capitalized	**(20,394)**	(13,642)
Other income (expense), net	**(257)**	30
Total other income and (expense)	**(20,651)**	(13,612)
Earnings Before Income Taxes	**44,022**	42,731
Income taxes	**14,830**	13,415
Net Income	**$ 29,192**	$ 29,316

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (UNAUDITED)

	For the Three Months Ended March 31,	
	2013	2012
	(in thousands)	
Net Income	**$ 29,192**	$ 29,316
Other comprehensive income (loss):		
Qualifying hedges:		
Changes in fair value, net of tax of $- and $(173), respectively	**—**	(274)
Reclassification adjustment for amounts included in net income, net of tax of $1,045 and $956, respectively	**1,634**	1,510
Total other comprehensive income (loss)	**1,634**	1,236
Comprehensive Income	**$ 30,826**	$ 30,552

The accompanying notes as they relate to Southern Power are an integral part of these condensed financial statements.

SOUTHERN POWER COMPANY AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)

	For the Three Months Ended March 31,	
	2013	2012
	(in thousands)	
Operating Activities:		
Net income	**$ 29,192**	$ 29,316
Adjustments to reconcile net income to net cash provided from operating activities —		
Depreciation and amortization, total	**42,790**	34,887
Deferred income taxes	**13,587**	9,917
Investment tax credits	**(493)**	(3,900)
Deferred revenues	**(20,432)**	(16,686)
Mark-to-market adjustments	**(2,746)**	6,467
Other, net	**2,979**	1,326
Changes in certain current assets and liabilities —		
-Receivables	**11,743**	12,400
-Fossil fuel stock	**1,840**	(755)
-Materials and supplies	**(1,546)**	(1,167)
-Prepaid income taxes	**1,600**	(5,105)
-Other current assets	**1,324**	(2,083)
-Accounts payable	**(6,933)**	(14,590)
-Accrued taxes	**4,155**	4,375
-Accrued interest	**(10,841)**	(10,172)
-Other current liabilities	**(314)**	(2)
Net cash provided from operating activities	**65,905**	44,228
Investing Activities:		
Property additions	**(58,553)**	(32,450)
Change in construction payables	**3,704**	(999)
Payments pursuant to long-term service agreements	**(11,741)**	(11,415)
Other investing activities	**(224)**	(2,848)
Net cash used for investing activities	**(66,814)**	(47,712)
Financing Activities:		
Increase in notes payable, net	**76,985**	20,165
Proceeds —		
Capital contributions	**1,033**	1,219
Other long-term debt	**1,717**	—
Repayments — Other long-term debt	**(220)**	(150)
Payment of common stock dividends	**(32,280)**	(31,750)
Other financing activities	**678**	25
Net cash provided from (used for) financing activities	**47,913**	(10,491)
Net Change in Cash and Cash Equivalents	**47,004**	(13,975)
Cash and Cash Equivalents at Beginning of Period	**28,592**	16,943
Cash and Cash Equivalents at End of Period	**$ 75,596**	$ 2,968
Supplemental Cash Flow Information:		
Cash paid (received) during the period for —		
Interest (net of $- and $6,556 capitalized for 2013 and 2012, respectively)	**$ 28,120**	$ 20,966
Income taxes, net	**(179)**	10,820
Noncash transactions — accrued property additions at end of period	**8,907**	31,591

The accompanying notes as they relate to Southern Power are an integral part of these condensed financial statements.

SOUTHERN POWER COMPANY AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED BALANCE SHEETS (UNAUDITED)

Assets	At March 31, 2013	At December 31, 2012
	(in thousands)	
Current Assets:		
Cash and cash equivalents	**$ 75,596**	$ 28,592
Receivables —		
Customer accounts receivable	**64,391**	62,857
Other accounts receivable	**2,164**	3,135
Affiliated companies	**26,252**	38,269
Fossil fuel stock, at average cost	**19,776**	21,616
Materials and supplies, at average cost	**49,943**	46,370
Prepaid service agreements—current	**104,424**	80,629
Prepaid income taxes	**11,696**	4,498
Other prepaid expenses	**4,318**	5,637
Assets from risk management activities	**2,916**	375
Total current assets	**361,476**	291,978
Property, Plant, and Equipment:		
In service	**4,032,559**	4,059,839
Less accumulated provision for depreciation	**808,958**	786,620
Plant in service, net of depreciation	**3,223,601**	3,273,219
Construction work in progress	**80,502**	24,835
Total property, plant, and equipment	**3,304,103**	3,298,054
Other Property and Investments:		
Goodwill	**1,839**	1,839
Other intangible assets, net of amortization of $3,759 and $3,141 at March 31, 2013 and December 31, 2012, respectively	**45,360**	45,979
Total other property and investments	**47,199**	47,818
Deferred Charges and Other Assets:		
Prepaid long-term service agreements	**96,121**	100,921
Other deferred charges and assets — affiliated	**6,692**	3,468
Other deferred charges and assets — non-affiliated	**42,675**	37,688
Total deferred charges and other assets	**145,488**	142,077
Total Assets	**$ 3,858,266**	$ 3,779,927

The accompanying notes as they relate to Southern Power are an integral part of these condensed financial statements.

SOUTHERN POWER COMPANY AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED BALANCE SHEETS (UNAUDITED)

Liabilities and Stockholder's Equity	**At March 31, 2013**	At December 31, 2012
	(in thousands)	
Current Liabilities:		
Securities due within one year	**$ 98**	$ 259
Notes payable — non-affiliated	**147,953**	70,968
Accounts payable —		
Affiliated	**66,864**	65,832
Other	**22,197**	26,204
Accrued taxes —		
Accrued income taxes	**1,224**	87
Other accrued taxes	**6,915**	3,031
Accrued interest	**11,433**	22,259
Liabilities from risk management activities	**590**	669
Other current liabilities	**7,734**	8,263
Total current liabilities	**265,008**	197,572
Long-term Debt	**1,307,762**	1,306,099
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	**564,301**	550,685
Investment tax credits	**174,471**	167,130
Deferred capacity revenues — affiliated	**6,835**	19,514
Other deferred credits and liabilities — affiliated	**2,384**	2,638
Other deferred credits and liabilities — non-affiliated	**5,880**	5,863
Total deferred credits and other liabilities	**753,871**	745,830
Total Liabilities	**2,326,641**	2,249,501
Redeemable Noncontrolling Interest	**9,689**	8,069
Common Stockholder's Equity:		
Common stock, par value $.01 per share —		
Authorized — 1,000,000 shares		
Outstanding — 1,000 shares	**—**	—
Paid-in capital	**1,028,581**	1,027,548
Retained earnings	**492,497**	495,585
Accumulated other comprehensive income (loss)	**858**	(776)
Total common stockholder's equity	**1,521,936**	1,522,357
Total Liabilities and Stockholder's Equity	**$ 3,858,266**	$ 3,779,927

The accompanying notes as they relate to Southern Power are an integral part of these condensed financial statements.

FIRST QUARTER 2013 vs. FIRST QUARTER 2012

OVERVIEW

Southern Power and its subsidiaries construct, acquire, own, and manage generation assets, including renewable energy projects, and sell electricity at market-based rates in the wholesale market. Southern Power continues to execute its strategy through a combination of acquiring and constructing new power plants and by entering into PPAs primarily with investor owned utilities, independent power producers, municipalities, and electric cooperatives. In accordance with this overall growth strategy, on April 23, 2013 Southern Power and Turner Renewable Energy, LLC (TRE), through Southern Turner Renewable Energy, LLC (STR), a jointly-owned subsidiary owned 90% by Southern Power, acquired all of the outstanding membership interests of Campo Verde Solar, LLC (Campo Verde). Campo Verde is constructing a 139-MW solar facility in Southern California that is expected to begin commercial operation in the fourth quarter 2013. The output of the plant is contracted under a 20-year PPA with San Diego Gas & Electric Company, a subsidiary of Sempra Energy. In general, Southern Power has constructed or acquired new generating capacity only after entering into long-term capacity contracts for the new facilities. See Note (I) to the Condensed Financial Statements herein for additional information.

To evaluate operating results and to ensure Southern Power's ability to meet its contractual commitments to customers, Southern Power focuses on several key performance indicators. These indicators include peak season equivalent forced outage rate (Peak Season EFOR), contract availability, and net income. Peak Season EFOR defines the hours during peak demand times when Southern Power's generating units are not available due to forced outages (the lower the better). Contract availability measures the percentage of scheduled hours delivered. Net income is the primary measure of Southern Power's financial performance.

RESULTS OF OPERATIONS

Net Income

First Quarter 2013 vs. First Quarter 2012	
(change in millions)	*(% change)*
$(0.1)	(0.4)

Southern Power's net income for the first quarter 2013 was $29.2 million compared to $29.3 million for the corresponding period in 2012. The decrease was primarily due to increases in depreciation, interest expense, other operations and maintenance expenses, and income taxes, partially offset by an increase in capacity revenues due to an increase in total MWs of capacity under long-term contracts, primarily related to the Plant Nacogdoches contract which began in June 2012.

Wholesale Revenues – Non-Affiliates

First Quarter 2013 vs. First Quarter 2012	
(change in millions)	*(% change)*
$82.8	59.0

Wholesale revenues from sales to non-affiliates will vary depending on the energy demand of those customers and their generation capacity, as well as the market prices of wholesale energy compared to the cost of Southern Power's energy. Increases and decreases in revenues that are driven by fuel prices are accompanied by an increase or decrease in fuel costs and do not have a significant impact on net income.

Wholesale revenues from non-affiliates for the first quarter 2013 were $223.4 million compared to $140.6 million for the corresponding period in 2012. The increase was primarily due to a $61.4 million increase in energy sales, reflecting a 33.4% increase in the average price of energy and a 51.9% increase in KWH sales. The increase in

revenue was also due to a $21.4 million increase in capacity revenue primarily due to an increase in the total MWs of capacity under contract with non-affiliates.

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Power Sales Agreements" of Southern Power in Item 7 of the Form 10-K for additional information.

Wholesale Revenues – Affiliates

First Quarter 2013 vs. First Quarter 2012	
(change in millions)	*(% change)*
$(33.6)	(30.1)

Wholesale revenues from sales to affiliated companies will vary depending on demand and the availability and cost of generating resources at each company. Sales to affiliate companies that are not covered by PPAs are made in accordance with the IIC, as approved by the FERC.

Wholesale revenues from affiliates for the first quarter 2013 were $78.2 million compared to $111.8 million for the corresponding period in 2012. The decrease was primarily the result of a $31.6 million decrease in energy sales under the IIC, reflecting a 54.6% decrease in KWH sales, partially offset by a 24.6% increase in the average price of energy.

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Power Sales Agreements" of Southern Power in Item 7 of the Form 10-K for additional information.

Fuel and Purchased Power Expenses

	First Quarter 2013 vs. First Quarter 2012	
	(change in millions)	*(% change)*
Fuel	$30.3	34.0
Purchased power – non-affiliates	(6.1)	(29.4)
Purchased power – affiliates	5.5	236.1
Total fuel and purchased power expenses	$29.7	

Southern Power PPAs generally provide that the purchasers are responsible for substantially all of the cost of fuel. Consequently, any increase or decrease in fuel costs is generally accompanied by an increase or decrease in related fuel revenues and does not have a significant impact on net income. Southern Power is responsible for the cost of fuel for generating units that are not covered under PPAs. Power from these generating units is sold into the market or sold to affiliates under the IIC.

Purchased power expenses will vary depending on demand and the availability and cost of generating resources throughout the Southern Company system and other contract resources. Load requirements are submitted to the Power Pool on an hourly basis and are fulfilled with the lowest cost alternative, whether that is generation owned by Southern Power, affiliate-owned generation, or external purchases.

In the first quarter 2013, total fuel and purchased power expenses were $141.8 million compared to $112.1 million for the corresponding period in 2012. Fuel and purchased power expenses increased $33.0 million due to a 33.3% increase in the average cost of fuel and a 17.8% increase in the average cost of purchased power. The increase was partially offset by a $3.2 million decrease associated with a 1.8% net decrease in the volume of KWHs generated and purchased.

In the first quarter 2013, fuel expense was $119.4 million compared to $89.1 million for the corresponding period in 2012. The increase was due to a $29.6 million increase associated with the average cost of fuel per KWH generated and a $0.7 million increase associated with the volume of KWHs generated.

In the first quarter 2013, purchased power expense was $22.4 million compared to $23.0 million for the corresponding period in 2012. The decrease was due to a $3.9 million decrease associated with the volume of KWHs purchased, partially offset by a $3.4 million increase associated with the cost of purchased power.

Other Operations and Maintenance Expenses

First Quarter 2013 vs. First Quarter 2012	
(change in millions)	*(% change)*
$2.6	5.3

In the first quarter 2013, other operations and maintenance expenses were $51.0 million compared to $48.4 million for the corresponding period in 2012. The increase was primarily due to operating costs associated with Plant Nacogdoches placed in service in June 2012, Plant Apex placed in service in July 2012, Plant Granville placed in service in October 2012, and Plant Cleveland placed in service in December 2012.

Depreciation and Amortization

First Quarter 2013 vs. First Quarter 2012	
(change in millions)	*(% change)*
$8.3	25.8

In the first quarter 2013, depreciation and amortization was $40.2 million compared to $31.9 million for the corresponding period in 2012. The increase was primarily due to an increase in plant in service, including the additions of Plants Nacogdoches, Apex, Granville, and Cleveland.

Interest Expense, Net of Amounts Capitalized

First Quarter 2013 vs. First Quarter 2012	
(change in millions)	*(% change)*
$6.8	49.5

In the first quarter 2013, interest expense, net of amounts capitalized was $20.4 million compared to $13.6 million for the corresponding period in 2012. The increase was primarily due to a decrease in capitalized interest resulting from the completion of Plants Nacogdoches and Cleveland in June 2012 and December 2012, respectively.

Income Taxes

First Quarter 2013 vs. First Quarter 2012	
(change in millions)	*(% change)*
$1.4	10.5

In the first quarter 2013, income taxes were $14.8 million compared to $13.4 million for the corresponding period in 2012. The increase was primarily due to a $2.2 million benefit received in 2012 related to prior year tax adjustments and a $0.6 million increase associated with higher pre-tax earnings, partially offset by a $1.7 million decrease related to an increase in the amount of tax benefit recognized from investment tax credits (ITCs) compared to the first quarter 2012.

FUTURE EARNINGS POTENTIAL

The results of operations discussed above are not necessarily indicative of Southern Power's future earnings potential. The level of Southern Power's future earnings depends on numerous factors that affect the opportunities, challenges, and risks of Southern Power's competitive wholesale business. These factors include: Southern Power's ability to achieve sales growth while containing costs; regulatory matters; creditworthiness of customers; total generating capacity available in Southern Power's target market areas; the successful remarketing of capacity as current contracts expire; and Southern Power's ability to execute its acquisition strategy and to construct generating facilities. Other factors that could influence future earnings include weather, demand, generation patterns, and operational limitations. For additional information relating to these issues, see RISK FACTORS in Item 1A and MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL of Southern Power in Item 7 of the Form 10-K.

Environmental Matters

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters" of Southern Power in Item 7 of the Form 10-K for information on the development by federal and state environmental regulatory agencies of additional control strategies for emissions of air pollution from industrial sources, including electric generating facilities. Compliance with possible additional federal or state legislation or regulations related to global climate change, air quality, or other environmental and health concerns could also significantly affect Southern Power. While Southern Power's PPAs generally contain provisions that permit charging the counterparty with some of the new costs incurred as a result of changes in environmental laws and regulations, the full impact of any such regulatory or legislative changes cannot be determined at this time.

Water Quality

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations – Water Quality" of Southern Power in Item 7 of the Form 10-K for additional information regarding the EPA's proposed revision of the current steam electric effluent guidelines. On April 19, 2013, the EPA signed a proposed rule which requests comments on a range of potential regulatory options for addressing certain wastestreams from steam electric power plants. These regulations could result in the installation of additional controls at certain of Southern Power's facilities, which could result in capital expenditures and compliance costs. The ultimate impact of these proposed regulations will, however, depend on the specific requirements of the final rule and the outcome of any legal challenges and cannot be determined at this time.

Income Tax Matters

Investment Tax Credits

In 2009, President Obama signed into law the American Recovery and Reinvestment Act of 2009 (ARRA). Major tax incentives in the ARRA included renewable energy incentives. Southern Power has recognized ITCs under the renewable energy incentives related to Plants Nacogdoches, Cimarron, Apex, Granville, and Spectrum, which have had a material impact on cash flows and net income. On January 2, 2013, the American Taxpayer Relief Act of 2012 (ATRA) was signed into law. The ATRA retroactively extended several renewable energy incentives through 2013, including extending ITCs for biomass projects which begin construction before January 1, 2014.

Acquisitions

Campo Verde Solar, LLC Acquisition

On April 23, 2013, Southern Power and TRE, through STR, acquired all of the outstanding membership interests of Campo Verde from First Solar, Inc., the developer of the project. Campo Verde is constructing a 139-MW solar photovoltaic facility in Southern California. The solar facility is expected to begin commercial operation in the fourth quarter 2013. The output of the plant is contracted under a 20-year PPA with San Diego Gas & Electric Company, a subsidiary of Sempra Energy, that is expected to begin in the fourth quarter 2013. See Note (I) to the Condensed Financial Statements herein for additional information.

Construction Projects

Spectrum Nevada Solar, LLC Acquisition

In September 2012, Southern Power and TRE, through STR, acquired all of the outstanding membership interests of Spectrum Nevada Solar, LLC (Spectrum) from Sun Edison, LLC, the original developer of the project. Spectrum is constructing a 30-MW solar photovoltaic facility in North Las Vegas, Nevada. The solar facility is expected to begin commercial operation in mid-2013. Construction costs incurred through March 31, 2013 were $62.8 million. The total estimated cost of the project is expected to be approximately $118.0 million.

Power Sales Agreements

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Power Sales Agreements" of Southern Power in Item 7 of the Form 10-K for additional information regarding Southern Power's PPAs with investor-owned utilities, independent power purchasers, municipalities, and electric cooperatives.

On April 23, 2013, a subsidiary of Southern Power assumed a PPA with San Diego Gas & Electric Company in connection with the acquisition of Campo Verde. The solar facility is expected to begin commercial operation in the fourth quarter 2013.

Other Matters

Southern Power is involved in various other matters being litigated and regulatory matters that could affect future earnings. In addition, Southern Power is subject to certain claims and legal actions arising in the ordinary course of business. Southern Power's business activities are subject to extensive governmental regulation related to public health and the environment, such as regulation of air emissions and water discharges. Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements, such as air quality and water standards, has increased generally throughout the U.S. In particular, personal injury, property damage, and other claims for damages alleged to have been caused by carbon dioxide and other emissions and alleged exposure to hazardous materials, and/or requests for injunctive relief in connection with such matters, have become more frequent.

The ultimate outcome of such pending or potential litigation against Southern Power and its subsidiaries cannot be predicted at this time; however, for current proceedings not specifically reported in Note (B) to the Condensed Financial Statements herein or in Note 3 to the financial statements of Southern Power in Item 8 of the Form 10-K, management does not anticipate that the ultimate liabilities, if any, arising from such current proceedings would have a material effect on Southern Power's financial statements.

See the Notes to the Condensed Financial Statements herein for a discussion of various other contingencies and other matters being litigated which may affect future earnings potential.

ACCOUNTING POLICIES

Application of Critical Accounting Policies and Estimates

Southern Power prepares its consolidated financial statements in accordance with GAAP. Significant accounting policies are described in Note 1 to the financial statements of Southern Power in Item 8 of the Form 10-K. In the application of these policies, certain estimates are made that may have a material impact on Southern Power's results of operations and related disclosures. Different assumptions and measurements could produce estimates that are significantly different from those recorded in the financial statements. See MANAGEMENT'S DISCUSSION AND ANALYSIS – ACCOUNTING POLICIES – "Application of Critical Accounting Policies and Estimates" of Southern Power in Item 7 of the Form 10-K for a complete discussion of Southern Power's critical accounting policies and estimates related to Revenue Recognition, Impairment of Long Lived Assets and Intangibles, Acquisition Accounting, Contingent Obligations, Depreciation, and Investment Tax Credits.

FINANCIAL CONDITION AND LIQUIDITY

Overview

Southern Power's financial condition remained stable at March 31, 2013. Southern Power intends to continue to monitor its access to short-term and long-term capital markets as well as its bank credit arrangements as needed to meet future capital and liquidity needs. See "Sources of Capital" herein for additional information on lines of credit.

Net cash provided from operating activities totaled $65.9 million for the first three months of 2013, an increase of $21.7 million as compared to the first three months of 2012. The increase in cash provided from operating activities was primarily due to the timing of payments resulting in a smaller increase in prepaid income tax and a smaller reduction in accounts payable compared to the first quarter 2012. Net cash used for investing activities totaled $66.8 million for the first three months of 2013 primarily due to expenditures related to the construction of Plant Spectrum and payments pursuant to long-term service agreements. Net cash provided from financing activities totaled $47.9 million for the first three months of 2013 primarily due to an increase in notes payable, partially offset by payment of common stock dividends. Fluctuations in cash flow from financing activities vary year to year based on capital needs and the maturity or redemption of securities.

Significant asset changes in the balance sheet for the first three months of 2013 include a $47.0 million increase in cash due to the timing of cash transactions; a $12.0 million decrease in accounts receivable from affiliated companies primarily due to lower energy sales under the IIC; a $23.8 million increase in prepaid service agreements-current due to the timing of plant outages; and a $55.7 million increase in CWIP primarily due to expenditures on Plant Spectrum.

Significant liability and stockholder's equity changes in the balance sheet for the first three months of 2013 include a $77.0 million increase in notes payable to non-affiliates due to the timing of cash transactions; a $10.8 million decrease in accrued interest due to scheduled debt service; a $13.6 million increase in accumulated deferred income taxes primarily due to bonus depreciation; and a $12.7 million decrease in deferred capacity revenues-affiliated due to seasonality.

Capital Requirements and Contractual Obligations

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" of Southern Power in Item 7 of the Form 10-K for a description of Southern Power's capital requirements for its construction program, scheduled maturities of long-term debt, as well as the related interest, leases, derivative obligations, purchase commitments, and unrecognized tax benefits. There are no requirements through March 31, 2014 to fund maturities of long-term debt.

The construction program is subject to periodic review and revision; these amounts include estimates for potential plant acquisitions and new construction as well as ongoing capital improvements and work to be performed under long-term service agreements. Planned expenditures for plant acquisitions may vary due to market opportunities and

Southern Power's ability to execute its growth strategy. Actual construction costs may vary from these estimates because of changes in factors such as: business conditions; environmental statutes and regulations; FERC rules and regulations; load projections; legislation; the cost and efficiency of construction labor, equipment, and materials; project scope and design changes; and the cost of capital.

Sources of Capital

Southern Power may use operating cash flows, external funds, or equity capital or loans from Southern Company to finance any new projects, acquisitions, and ongoing capital requirements. Southern Power expects to generate external funds from the issuance of unsecured senior debt and commercial paper or utilization of credit arrangements from banks. However, the amount, type, and timing of any future financings, if needed, will depend upon prevailing market conditions, regulatory approval, and other factors. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FINANCIAL CONDITION AND LIQUIDITY – "Sources of Capital" of Southern Power in Item 7 of the Form 10-K for additional information.

Southern Power's current liabilities frequently exceed current assets due to the use of short-term debt as a funding source, as well as cash needs which can fluctuate significantly due to the seasonality of the business.

To meet liquidity and capital resource requirements, Southern Power had at March 31, 2013 cash and cash equivalents of approximately $75.6 million and a committed credit facility of $500 million (Facility). In February 2013, Southern Power amended the Facility, which extended the maturity date from 2016 to 2018. The Facility contains a covenant that limits the ratio of debt to capitalization (each as defined in the Facility) to a maximum of 65% and contains a cross default provision that is restricted only to the indebtedness of Southern Power. Southern Power is currently in compliance with all such covenants. Proceeds from this Facility may be used for working capital and general corporate purposes as well as liquidity support for Southern Power's commercial paper program. See Note 6 to the financial statements of Southern Power under "Bank Credit Arrangements" in Item 8 of the Form 10-K and Note (E) to the Condensed Financial Statements under "Bank Credit Arrangements" herein for additional information.

Southern Power's commercial paper program is used to finance acquisition and construction costs related to electric generating facilities and for general corporate purposes.

Details of short-term borrowings were as follows:

	Short-term Debt at March 31, 2013		Short-term Debt During the Period [a]		
	Amount Outstanding	Weighted Average Interest Rate	Average Outstanding	Weighted Average Interest Rate	Maximum Amount Outstanding
	(in millions)		*(in millions)*		*(in millions)*
Commercial paper	$ 148	0.4%	$ 44	0.4%	$ 148

(a) Average and maximum amounts are based upon daily balances during the three-month period ended March 31, 2013.

Management believes that the need for working capital can be adequately met by utilizing the commercial paper program, the Facility, and cash.

Credit Rating Risk

Southern Power does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. There are certain contracts that could require collateral, but not accelerated payment, in the event of a credit rating change to BBB and Baa2, or BBB- and/or Baa3 or below. These contracts are for physical electricity purchases and sales, fuel transportation and storage, and energy price risk management.

The maximum potential collateral requirements under these contracts at March 31, 2013 were as follows:

Credit Ratings	Maximum Potential Collateral Requirements
	(in millions)
At BBB and Baa2	$ 9
At BBB- and/or Baa3	467
Below BBB- and/or Baa3	1,203

Included in these amounts are certain agreements that could require collateral in the event that one or more Power Pool participant has a credit rating change to below investment grade. Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. Additionally, any credit rating downgrade could impact Southern Power's ability to access capital markets, particularly the short-term debt market.

In addition, through the acquisition of Plant Rowan, Southern Power assumed a PPA with North Carolina Municipal Power Agency No. 1 that could require collateral, but not accelerated payment, in the event of a downgrade of Southern Power's credit. The PPA requires credit assurances without stating a specific credit rating. The amount of collateral required would depend upon actual losses, if any, resulting from a credit downgrade.

Market Price Risk

Southern Power is exposed to market risks, including changes in interest rates, certain energy-related commodity prices, and, occasionally, currency exchange rates. To manage the volatility attributable to these exposures, Southern Power takes advantage of natural offsets and enters into various derivative transactions for the remaining exposures pursuant to Southern Power's policies in areas such as counterparty exposure and risk management practices. Southern Power's policy is that derivatives are to be used primarily for hedging purposes and mandates strict adherence to all applicable risk management policies. Derivative positions are monitored using techniques including, but not limited to, market valuation, value at risk, stress tests, and sensitivity analysis.

Southern Power's market risk exposure relative to interest rate changes for the first quarter 2013 has not changed materially compared with the December 31, 2012 reporting period. Since a significant portion of outstanding indebtedness bears interest at fixed rates, Southern Power is not aware of any facts or circumstances that would significantly affect exposure on existing indebtedness in the near term. However, the impact on future financing costs cannot now be determined.

Because energy from Southern Power's facilities is primarily sold under long-term PPAs with tolling agreements and provisions shifting substantially all of the responsibility for fuel cost to the counterparties, Southern Power's exposure to market volatility in commodity fuel prices and prices of electricity is generally limited. However, Southern Power has been and may continue to be exposed to market volatility in energy-related commodity prices as a result of sales of uncontracted generating capacity.

The changes in fair value of energy-related derivative contracts for the three months ended March 31, 2013 were as follows:

	First Quarter 2013 Changes
	Fair Value
	(in millions)
Contracts outstanding at the beginning of the period, assets (liabilities), net	$ 0.8
Contracts realized or settled	0.2
Current period changes[(a)]	2.6
Contracts outstanding at the end of the period, assets (liabilities), net	$ 3.6

(a) Current period changes also include the changes in fair value of new contracts entered into during the period, if any.

The change in the fair value positions of the energy-related derivative contracts for the three months ended March 31, 2013 was an increase of $2.8 million which is due to both power and natural gas positions. The changes are attributable to both the volume and prices of power and natural gas as follows:

	March 31, 2013	December 31, 2012
Power – net purchased or (sold)		
MWHs *(in thousands)*	**(52.8)**	—
Weighted average contract cost per MWH above (below) market prices *(in dollars)*	**$ 3.58**	$ —
Natural gas net purchased		
Commodity – million mmBtu	**5.2**	5.0
Commodity – weighted average contract cost per mmBtu above (below) market prices *(in dollars)*	**$ (0.57)**	$ (0.02)

The net fair value of energy-related derivative contracts by hedge designation reflected in the financial statements as assets (liabilities) consists of the following:

Asset (Liability) Derivatives	March 31, 2013	December 31, 2012
	(in millions)	
Cash flow hedges	**$ —**	$ —
Not designated	**3.6**	0.8
Total fair value	**$ 3.6**	$ 0.8

Gains and losses on energy-related derivatives used by Southern Power to hedge anticipated purchases and sales are initially deferred in AOCI before being recognized in income in the same period as the hedged transaction. Gains and losses on energy-related derivative contracts that are not designated or fail to qualify as hedges are recognized in Southern Power's statements of income as incurred.

For Southern Power's energy-related derivatives not designated as hedging instruments, a substantial portion of the pre-tax realized and unrealized gains and losses is associated with hedging fuel price risk of certain PPA customers and has no impact on net income or on fuel expense as presented in Southern Power's statements of income. As a result, for the three months ended March 31, 2013, the pre-tax effects of energy-related derivatives not designated as hedging instruments on Southern Power's statements of income were immaterial.

Southern Power uses over-the-counter contracts that are not exchange traded but are fair valued using prices which are market observable, and thus fall into Level 2. See Note (C) to the Condensed Financial Statements herein for further discussion on fair value measurements. The maturities of the energy-related derivative contracts, which are all Level 2 of the fair value hierarchy, at March 31, 2013 were as follows:

	March 31, 2013 Fair Value Measurements			
	Total Fair Value	Maturity		
		Year 1	Years 2&3	Years 4&5
		(in millions)		
Level 1	$ —	$ —	$ —	$ —
Level 2	3.6	2.3	0.2	1.1
Level 3	—	—	—	—
Fair value of contracts outstanding at end of period	$ 3.6	$ 2.3	$ 0.2	$ 1.1

For additional information, see MANAGEMENT'S DISCUSSION AND ANALYSIS – FINANCIAL CONDITION AND LIQUIDITY – "Market Price Risk" of Southern Power in Item 7 and Note 1 under "Financial Instruments"

and Note 9 to the financial statements of Southern Power in Item 8 of the Form 10-K and Note (H) to the Condensed Financial Statements herein.

Financing Activities

During the three months ended March 31, 2013, Southern Power prepaid $0.2 million of long-term debt to TRE.

In March 2013, Southern Power issued an additional $1.7 million under a promissory note, due September 30, 2032, to TRE related to the financing of Spectrum.

Subsequent to March 31, 2013, Southern Power issued a $5.6 million promissory note, due April 30, 2033, to TRE related to the financing of Campo Verde.

In addition to any financings that may be necessary to meet capital requirements and contractual obligations, Southern Power plans to continue, when economically feasible, a program to retire higher-cost securities and replace these obligations with lower-cost capital if market conditions permit.

NOTES TO THE CONDENSED FINANCIAL STATEMENTS
FOR
THE SOUTHERN COMPANY AND SUBSIDIARY COMPANIES
ALABAMA POWER COMPANY
GEORGIA POWER COMPANY
GULF POWER COMPANY
MISSISSIPPI POWER COMPANY
SOUTHERN POWER COMPANY AND SUBSIDIARY COMPANIES

INDEX TO APPLICABLE NOTES TO
FINANCIAL STATEMENTS BY REGISTRANT

Registrant	**Applicable Notes**
Southern Company	A, B, C, D, E, F, G, H, I, J, K
Alabama Power	A, B, C, E, F, G, H
Georgia Power	A, B, C, E, F, G, H
Gulf Power	A, B, C, E, F, G, H
Mississippi Power	A, B, C, E, F, G, H
Southern Power	A, B, C, E, G, H, I

NOTES TO THE CONDENSED FINANCIAL STATEMENTS:

(A) INTRODUCTION

The condensed quarterly financial statements of each registrant included herein have been prepared by such registrant, without audit, pursuant to the rules and regulations of the SEC. The Condensed Balance Sheets as of December 31, 2012 have been derived from the audited financial statements of each registrant. In the opinion of each registrant's management, the information regarding such registrant furnished herein reflects all adjustments, which, except as otherwise disclosed, are of a normal recurring nature, necessary to present fairly the results of operations for the periods ended March 31, 2013 and 2012. Certain information and footnote disclosures normally included in annual financial statements prepared in accordance with GAAP have been condensed or omitted pursuant to such rules and regulations, although each registrant believes that the disclosures regarding such registrant are adequate to make the information presented not misleading. Disclosures which would substantially duplicate the disclosures in the Form 10-K (with respect to Southern Company, Alabama Power, Georgia Power, Gulf Power, and Southern Power) and the Form 10-K/A (with respect to Mississippi Power) and details which have not changed significantly in amount or composition since the filings of the Form 10-K or the Form 10-K/A, as applicable, are generally omitted from this Quarterly Report on Form 10-Q unless specifically required by GAAP. Therefore, these Condensed Financial Statements should be read in conjunction with the financial statements and the notes thereto included in the Form 10-K (with respect to Southern Company, Alabama Power, Georgia Power, Gulf Power, and Southern Power) and the Form 10-K/A (with respect to Mississippi Power). Due to the seasonal variations in the demand for energy, operating results for the periods presented are not necessarily indicative of the operating results to be expected for the full year.

Certain prior year data presented in the financial statements have been reclassified to conform to the current year presentation.

(B) CONTINGENCIES AND REGULATORY MATTERS

See Note 3 to the financial statements of the registrants (other than Mississippi Power) in Item 8 of the Form 10-K and Note 3 to the financial statements of Mississippi Power in Item 8 of the Form 10-K/A for information relating to various lawsuits, other contingencies, and regulatory matters.

General Litigation Matters

Each registrant is subject to certain claims and legal actions arising in the ordinary course of business. In addition, business activities of Southern Company's subsidiaries are subject to extensive governmental regulation related to public health and the environment, such as regulation of air emissions and water discharges. Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements, such as air quality and water standards, has increased generally throughout the U.S. In particular, personal injury, property damage, and other claims for damages alleged to have been caused by carbon dioxide (CO_2) and other emissions, coal combustion byproducts, and alleged exposure to hazardous materials, and/or requests for injunctive relief in connection with such matters, have become more frequent. The ultimate outcome of such pending or potential litigation against each registrant and any subsidiaries cannot be predicted at this time; however, for current proceedings not specifically reported herein or in Note 3 to the financial statements of each registrant (other than Mississippi Power) in Item 8 of the Form 10-K and Note 3 to the financial statements of Mississippi Power in Item 8 of the Form 10-K/A, management does not anticipate that the ultimate liabilities, if any, arising from such current proceedings would have a material effect on such registrant's financial statements.

Environmental Matters

New Source Review Actions

In 1999, the EPA brought a civil action in the U.S. District Court for the Northern District of Georgia against certain Southern Company subsidiaries, including Alabama Power and Georgia Power, alleging that these subsidiaries had violated the NSR provisions of the Clean Air Act and related state laws at certain coal-fired generating facilities. The EPA alleged NSR violations at five coal-fired generating facilities operated by Alabama Power, including a unit co-owned by Mississippi Power, and three coal-fired generating facilities operated by Georgia Power, including a unit co-owned by Gulf Power. The civil action sought penalties and injunctive relief, including an order requiring installation of the best available control technology at the affected units. The case against Georgia Power (including claims related to the unit co-owned by Gulf Power) was administratively closed in 2001 and has not been reopened. After Alabama Power was dismissed from the original action, the EPA filed a separate action in 2001 against Alabama Power (including claims related to the unit co-owned by Mississippi Power) in the U.S. District Court for the Northern District of Alabama.

In 2006, the U.S. District Court for the Northern District of Alabama entered a consent decree, resolving claims relating to the alleged NSR violations at Plant Miller. In 2010, the EPA dismissed five of its eight remaining claims against Alabama Power, leaving only three claims, including one relating to the unit co-owned by Mississippi Power. In 2011, the U.S. District Court for the Northern District of Alabama granted Alabama Power summary judgment on all remaining claims and dismissed the case with prejudice. That judgment is on appeal to the U.S. Court of Appeals for the Eleventh Circuit. In February 2012, the EPA filed a motion in the U.S. District Court for the Northern District of Alabama seeking vacatur of the judgment and recusal of the judge in the case involving Alabama Power.

Southern Company and each traditional operating company believe each such traditional operating company complied with applicable laws and regulations in effect at the time the work in question took place. The Clean Air Act authorizes maximum civil penalties of $25,000 to $37,500 per day, per violation, depending on the date of the alleged violation. An adverse outcome could require substantial capital expenditures that cannot be determined at this time and could possibly require payment of substantial penalties. Such expenditures could affect future results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates. The ultimate outcome of these matters cannot be determined at this time.

Climate Change Litigation

Kivalina Case

In 2008, the Native Village of Kivalina and the City of Kivalina filed a lawsuit in the U.S. District Court for the Northern District of California against several electric utilities (including Southern Company), several oil companies, and a coal company. The plaintiffs allege that the village is being destroyed by erosion allegedly caused by global warming that the plaintiffs attribute to emissions of greenhouse gases by the defendants. The plaintiffs assert claims for public and private nuisance and contend that some of the defendants (including Southern Company) acted in concert and are therefore jointly and severally liable for the plaintiffs' damages. The suit seeks damages for lost property values and for the cost of relocating the village, which is alleged to be $95 million to $400 million. In 2009, the U.S. District Court for the Northern District of California granted the defendants' motions to dismiss the case. In September 2012, the U.S. Court of Appeals for the Ninth Circuit upheld the U.S. District Court for the Northern District of California's dismissal of the case. In November 2012, the U.S. Court of Appeals for the Ninth Circuit denied the plaintiffs' request for review of the decision. On February 25, 2013, the plaintiffs filed a petition for writ of certiorari with the U.S. Supreme Court. Southern Company believes that these claims are without merit. While Southern Company believes the likelihood of loss is remote based on existing case law, it is not possible to predict with certainty whether Southern Company will incur any liability in connection with this matter. The ultimate outcome of this matter cannot be determined at this time.

Hurricane Katrina Case

In 2005, immediately following Hurricane Katrina, a lawsuit was filed in the U.S. District Court for the Southern District of Mississippi by Ned Comer on behalf of Mississippi residents seeking recovery for property damage and personal injuries caused by Hurricane Katrina. In 2006, the plaintiffs amended the complaint to include Southern Company and many other electric utilities, oil companies, chemical companies, and coal producers. The plaintiffs allege that the defendants contributed to climate change, which contributed to the intensity of Hurricane Katrina. In 2007, the U.S. District Court for the Southern District of Mississippi dismissed the case. On appeal to the U.S. Court of Appeals for the Fifth Circuit, a three-judge panel reversed the U.S. District Court for the Southern District of Mississippi, holding that the case could proceed, but, on rehearing, the full U.S. Court of Appeals for the Fifth Circuit dismissed the plaintiffs' appeal, resulting in reinstatement of the decision of the U.S. District Court for the Southern District of Mississippi in favor of the defendants. In 2011, the plaintiffs filed an amended version of their class action complaint, arguing that the earlier dismissal was on procedural grounds and under Mississippi law the plaintiffs have a right to re-file. The amended complaint was also filed against numerous chemical, coal, oil, and utility companies, including Alabama Power, Georgia Power, Gulf Power, and Southern Power. In March 2012, the U.S. District Court for the Southern District of Mississippi dismissed the plaintiffs' amended complaint. In April 2012, the plaintiffs appealed the case to the U.S. Court of Appeals for the Fifth Circuit. Each Southern Company entity named in the lawsuit believes that these claims are without merit. While each Southern Company entity named in the lawsuit believes the likelihood of loss is remote based on existing case law, it is not possible to predict with certainty whether any Southern Company entity named in the lawsuit will incur any liability in connection with this matter. The ultimate outcome of this matter cannot be determined at this time.

Environmental Remediation

The Southern Company system must comply with environmental laws and regulations that cover the handling and disposal of waste and releases of hazardous substances. Under these various laws and regulations, the Southern Company system could incur substantial costs to clean up properties. The traditional operating companies have each received authority from their respective state PSCs to recover approved environmental compliance costs through regulatory mechanisms. These rates are adjusted annually or as necessary within limits approved by the state PSCs.

Georgia Power's environmental remediation liability as of March 31, 2013 was $18 million. Georgia Power has been designated or identified as a potentially responsible party (PRP) at sites governed by the Georgia Hazardous Site Response Act and/or by the federal Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA), including a large site in Brunswick, Georgia on the CERCLA National Priorities List (NPL). The parties have completed the removal of wastes from the Brunswick site as ordered by the EPA. Additional cleanup and claims for recovery of natural resource damages at this site or for the assessment and potential cleanup of other sites on the Georgia Hazardous Sites Inventory and the CERCLA NPL are anticipated.

Georgia Power and numerous other entities have been designated by the EPA as PRPs at the Ward Transformer Superfund site located in Raleigh, North Carolina. In 2011, the EPA issued a Unilateral Administrative Order (UAO) to Georgia Power and 22 other parties, ordering specific remedial action of certain areas at the site. In 2011, Georgia Power filed a response with the EPA stating it has sufficient cause to believe it is not a liable party under CERCLA. The EPA notified Georgia Power in 2011 that it is considering enforcement options against Georgia Power and other non-complying UAO recipients. If the court determines that a respondent failed to comply with the UAO without sufficient cause, the EPA may also seek civil penalties of up to $37,500 per day for the violation and punitive damages of up to three times the costs incurred by the EPA as a result of the party's failure to comply with the UAO.

In addition to the EPA's action at this site, Georgia Power, along with many other parties, was sued in a private action by several existing PRPs for cost recovery related to the removal action. On February 1, 2013, the court granted Georgia Power's summary judgment motion ruling that Georgia Power has no liability in the private action. The plaintiffs may appeal the court's order to the U.S. Court of Appeals for the Fourth Circuit.

The ultimate outcome of these matters will depend upon the success of defenses asserted, the ultimate number of PRPs participating in the cleanup, and numerous other factors and cannot be determined at this time; however, as a

result of the regulatory treatment, they are not expected to have a material impact on Southern Company's or Georgia Power's financial statements. See Note 1 to the financial statements of Georgia Power under "Environmental Remediation" in Item 8 of the Form 10-K for additional information regarding the regulatory treatment.

Gulf Power's environmental remediation liability includes estimated costs of environmental remediation projects of approximately $57 million as of March 31, 2013. These estimated costs primarily relate to site closure criteria by the Florida Department of Environmental Protection (FDEP) for potential impacts to soil and groundwater from herbicide applications at Gulf Power substations. The schedule for completion of the remediation projects is subject to FDEP approval. The projects have been approved by the Florida PSC for recovery through Gulf Power's environmental cost recovery clause; therefore, there was no impact on net income as a result of these estimates.

In 2003, the Texas Commission on Environmental Quality (TCEQ) designated Mississippi Power as a PRP at a site in Texas. The site was owned by an electric transformer company that handled Mississippi Power's transformers as well as those of many other entities. The site owner is bankrupt and the State of Texas has entered into an agreement with Mississippi Power and several other utilities to investigate and remediate the site. The feasibility study/ presumptive remedy document was originally filed with TCEQ in 2011 and remains under consideration by the agency. Amounts expensed and accrued related to this work were not material. Hundreds of entities have received notices from the TCEQ requesting their participation in the anticipated site remediation. The final impact of this matter on Mississippi Power will depend upon further environmental assessment and the ultimate number of PRPs. The remediation expenses incurred by Mississippi Power are expected to be recovered through the ECO Plan.

The final outcome of these matters cannot be determined at this time. However, based on the currently known conditions at these sites and the nature and extent of activities relating to these sites, management of Southern Company, Georgia Power, Gulf Power, and Mississippi Power does not believe that additional liabilities, if any, at these sites would be material to their respective financial statements.

Nuclear Fuel Disposal Cost Litigation

Acting through the DOE and pursuant to the Nuclear Waste Policy Act of 1982, the U.S. government entered into contracts with Alabama Power and Georgia Power that require the DOE to dispose of spent nuclear fuel and high level radioactive waste generated at Plants Hatch and Farley and Plant Vogtle Units 1 and 2. The DOE failed to timely perform and has yet to commence the performance of its contractual and statutory obligation to dispose of spent nuclear fuel beginning no later than January 31, 1998. Consequently, Alabama Power and Georgia Power have pursued and continue to pursue legal remedies against the U.S. government for its partial breach of contract.

As a result of the first lawsuit, Georgia Power recovered approximately $27 million, based on its ownership interests, and Alabama Power recovered approximately $17 million, representing substantially all of the Southern Company system's direct costs of the expansion of spent nuclear fuel storage facilities at Plants Farley and Hatch and Plant Vogtle Units 1 and 2 from 1998 through 2004.

In 2008, Alabama Power and Georgia Power filed a second lawsuit against the U.S. government for the costs of continuing to store spent nuclear fuel at Plants Farley and Hatch and Plant Vogtle Units 1 and 2. Damages are being sought for the period from January 1, 2005 through December 31, 2010. Damages will continue to accrue until the issue is resolved or storage is provided. No amounts have been recognized in the financial statements as of March 31, 2013 for any potential recoveries from the second lawsuit. The final outcome of these matters cannot be determined at this time; however, no material impact on Southern Company's, Alabama Power's, or Georgia Power's net income is expected.

Sufficient pool storage capacity for spent fuel is available at Plant Vogtle Units 1 and 2 to maintain full-core discharge capability for both units into 2014. Construction of an on-site dry storage facility at Plant Vogtle Units 1 and 2 has begun. The facility is expected to begin operation in sufficient time to maintain full-core discharge capability, with additional on-site dry storage to be added as needed. At Plants Hatch and Farley, on-site dry spent fuel storage facilities are operational and can be expanded to accommodate spent fuel through the expected life of each plant.

FERC Matters

See Note 3 to the financial statements of Mississippi Power under "FERC Matters" in Item 8 of the Form 10-K/A for additional information regarding Mississippi Power's settlement agreement with its wholesale customers for revised rates related to the wholesale Municipal and Rural Associations (MRA) cost-based electric tariff. See Note 3 to the financial statements of Southern Company under "Integrated Coal Gasification Combined Cycle" in Item 8 of the Form 10-K, Note 3 to the financial statements of Mississippi Power under "Integrated Coal Gasification Combined Cycle" in Item 8 of the Form 10-K/A, and "Integrated Coal Gasification Combined Cycle" herein for information regarding Mississippi Power's construction of the Kemper IGCC.

In 2011, Mississippi Power filed a request with the FERC for an increase in wholesale base revenues under the MRA cost-based electric tariff. In March 2012, Mississippi Power entered into a settlement agreement with its wholesale customers which provided that base revenues would increase by approximately $22.6 million over a 12-month period with revised rates effective for services rendered beginning April 1, 2012. In March 2012, the FERC approved a motion to place interim rates into effect beginning in May 2012. In September 2012, Mississippi Power, with its wholesale customers, filed a final settlement agreement with the FERC. In November 2012, the settlement judge certified the settlement agreement to the FERC with the recommendation that it be approved. The FERC has not yet approved the settlement agreement.

On April 1, 2013, Mississippi Power reached a settlement agreement with its wholesale customers and filed a request with the FERC for an additional increase in the MRA cost-based electric tariff. The 2013 settlement agreement provides that base rates under the MRA cost-based electric tariff will increase by approximately $24.2 million over a 12-month period, with revised rates effective for services rendered beginning April 1, 2013. If the 2013 settlement agreement is approved by the FERC, the amount of base rate revenues to be received in 2013 from the agreed upon increase will be approximately $18.0 million.

The ultimate outcome of these matters cannot be determined at this time.

Retail Regulatory Matters

Alabama Power

Rate CNP

See Note 3 to the financial statements of Southern Company and Alabama Power under "Retail Regulatory Matters – Alabama Power – Rate CNP" and "Retail Regulatory Matters – Rate CNP" in Item 8 of the Form 10-K for additional information regarding Alabama Power's recovery of retail costs through Rate Certificated New Plant Power Purchase Agreement (Rate CNP PPA) and Rate Certificated New Plant Environmental (Rate CNP Environmental). Alabama Power's under recovered Rate CNP PPA balance at March 31, 2013 was $7 million as compared to $9 million at December 31, 2012. This under recovered balance at March 31, 2013 is included in deferred under recovered regulatory clause revenues on Southern Company's and Alabama Power's Condensed Balance Sheet herein. For Rate CNP PPA, this classification is based on an estimate, which includes such factors as purchased power capacity and energy demand. A change in any of these factors could have a material impact on the timing of any recovery of the under recovered retail costs. Alabama Power's under recovered Rate CNP Environmental balance at March 31, 2013 was $19 million as compared to $21 million at December 31, 2012. This under recovered balance at March 31, 2013 consists of $11 million in under recovered regulatory clause revenues and $8 million in deferred under recovered regulatory clause revenues on Southern Company's and Alabama Power's Condensed Balance Sheets herein. For Rate CNP Environmental, this classification is based on an estimate, which includes such factors as costs to comply with environmental mandates and energy demand. A change in any of these factors could have a material impact on the timing of any recovery of the under recovered retail costs.

Retail Energy Cost Recovery

See Note 3 to the financial statements of Southern Company and Alabama Power under "Retail Regulatory Matters – Alabama Power – Energy Cost Recovery" and "Retail Regulatory Matters – Energy Cost Recovery," respectively, in Item 8 of the Form 10-K for additional information regarding Alabama Power's energy cost recovery. Alabama Power's over recovered fuel costs at March 31, 2013 totaled $21 million as compared to an under recovered balance

of $4 million at December 31, 2012. The over recovered fuel costs at March 31, 2013 are included in other regulatory liabilities, current and the under recovered fuel costs at December 31, 2012 are included in deferred under recovered regulatory clause revenues on Southern Company's and Alabama Power's Condensed Balance Sheets herein. These classifications are based on estimates, which include such factors as weather, generation availability, energy demand, and the price of energy. A change in any of these factors could have a material impact on the timing of any return of the over recovered fuel costs.

Natural Disaster Cost Recovery

See Note 3 to the financial statements of Southern Company and Alabama Power under "Retail Regulatory Matters – Alabama Power – Natural Disaster Reserve" and "Retail Regulatory Matters – Natural Disaster Reserve," respectively, in Item 8 of the Form 10-K for additional information regarding natural disaster cost recovery. At March 31, 2013, the NDR had an accumulated balance of $93 million as compared to $103 million at December 31, 2012, which is included on Southern Company's and Alabama Power's Condensed Balance Sheets herein under other regulatory liabilities, deferred. The decrease in the NDR in the first quarter 2013 is a result of storm activity. The related accruals are reflected as operations and maintenance expenses on Southern Company's and Alabama Power's Condensed Statements of Income herein.

Georgia Power

Fuel Cost Recovery

See Note 3 to the financial statements of Southern Company and Georgia Power under "Retail Regulatory Matters – Georgia Power – Fuel Cost Recovery" and "Retail Regulatory Matters – Fuel Cost Recovery," respectively, in Item 8 of the Form 10-K for additional information.

As of March 31, 2013 and December 31, 2012, Georgia Power's fuel cost over recovery balance totaled $182 million and $230 million, respectively, and is included in current liabilities and other deferred credits and liabilities on Southern Company's and Georgia Power's Condensed Balance Sheets herein.

Fuel cost recovery revenues as recorded on the financial statements are adjusted for differences in actual recoverable fuel costs and amounts billed in current regulated rates. Accordingly, any changes in the billing factor will not have a significant effect on Southern Company's or Georgia Power's revenues or net income, but will affect cash flow.

Integrated Resource Plans

See Note 3 to the financial statements of Southern Company and Georgia Power under "Retail Regulatory Matters – Georgia Power – Integrated Resource Plans" and "Retail Regulatory Matters – Integrated Resource Plans," respectively, in Item 8 of the Form 10-K for additional information.

On April 17, 2013, the Georgia PSC approved the decertification of Plant Bowen Unit 6 (32 MWs), which was retired on April 25, 2013. The Georgia PSC is scheduled to vote on all other aspects of the 2013 IRP in July 2013. The ultimate outcome of this matter cannot be determined at this time.

Separately, on April 22, 2013, Georgia Power executed two PPAs to purchase energy from two wind farms with capacity totaling 250 MWs in southwest Oklahoma that will commence in 2016 and end in 2035. In addition, on April 29, 2013, Georgia Power executed a PPA for the purchase of 50 MWs of capacity and energy that will commence in 2015 and end in 2035. These PPAs are subject to Georgia PSC approval and, if approved, will result in contractual obligations of approximately $13 million in 2015, $47 million in 2016, $48 million in 2017, and $1.3 billion thereafter.

Nuclear Construction

See Note 3 to the financial statements of Southern Company and Georgia Power under "Retail Regulatory Matters – Georgia Power – Nuclear Construction" and "Retail Regulatory Matters – Nuclear Construction," respectively, in Item 8 of the Form 10-K for additional information regarding Georgia Power's construction of Plant Vogtle Units 3 and 4, the eighth Vogtle Construction Monitoring (VCM) report, and pending litigation.

In 2008, Georgia Power, acting for itself and as agent for the Owners, entered into an agreement (Vogtle 3 and 4 Agreement) with the Contractor, pursuant to which the Contractor agreed to design, engineer, procure, construct, and test Plant Vogtle Units 3 and 4. Under the terms of the Vogtle 3 and 4 Agreement, the Owners agreed to pay a purchase price that is subject to certain price escalations and adjustments, including fixed escalation amounts and index-based adjustments, as well as adjustments for change orders, and performance bonuses for early completion and unit performance. Each Owner is severally (and not jointly) liable for its proportionate share, based on its ownership interest, of all amounts owed to the Contractor under the Vogtle 3 and 4 Agreement. Georgia Power's proportionate share is 45.7%. The Vogtle 3 and 4 Agreement provides for liquidated damages upon the Contractor's failure to fulfill the schedule and performance guarantees. The Contractor's liability to the Owners for schedule and performance liquidated damages and warranty claims is subject to a cap.

Certain payment obligations of Westinghouse and Stone & Webster, Inc. under the Vogtle 3 and 4 Agreement are guaranteed by Toshiba Corporation and The Shaw Group, Inc., respectively. In the event of certain credit rating downgrades of any Owner, such Owner will be required to provide a letter of credit or other credit enhancement. The Owners may terminate the Vogtle 3 and 4 Agreement at any time for their convenience, provided that the Owners will be required to pay certain termination costs. The Contractor may terminate the Vogtle 3 and 4 Agreement under certain circumstances, including certain Owner suspension or delays of work, action by a governmental authority to permanently stop work, certain breaches of the Vogtle 3 and 4 Agreement by the Owners, Owner insolvency, and certain other events.

In 2009, the Georgia PSC approved inclusion of the Plant Vogtle Units 3 and 4 related CWIP accounts in rate base, and the State of Georgia enacted the Georgia Nuclear Energy Financing Act, which allows Georgia Power to recover financing costs for nuclear construction projects through annual adjustments to an NCCR tariff by including the related CWIP accounts in rate base during the construction period. The Georgia PSC approved increases to the NCCR tariff of approximately $223 million, $35 million, and $50 million, effective January 1, 2011, 2012, and 2013, respectively. Through the NCCR tariff, Georgia Power is collecting and amortizing to earnings approximately $91 million of financing costs, capitalized in 2009 and 2010, over the five-year period ending December 31, 2015, in addition to the ongoing financing costs. At March 31, 2013, approximately $50 million of these 2009 and 2010 costs remained unamortized in CWIP.

In 2009, the NRC issued an Early Site Permit and Limited Work Authorization which allowed limited work to begin on Plant Vogtle Units 3 and 4. The NRC certified the Westinghouse Design Control Document, as amended (DCD), for the AP1000 nuclear reactor design, effective December 30, 2011, and issued combined construction and operating licenses (COLs) in February 2012. Receipt of the COLs allowed full construction to begin.

In February 2012, separate groups of petitioners filed petitions in the U.S. Court of Appeals for the District of Columbia Circuit seeking judicial review of the NRC's issuance of the COLs and certification of the DCD. These petitions were consolidated in April 2012. Also in April 2012, another group of petitioners filed a motion to stay the effectiveness of the COLs with the U.S. District Court for the District of Columbia. In July 2012, the U.S. Court of Appeals for the District of Columbia Circuit denied the petitioners' motion to stay the effectiveness of the COLs. Georgia Power has intervened in, and is vigorously contesting, these petitions. Additional technical and procedural challenges to the construction and licensing of Plant Vogtle Units 3 and 4, at the federal and state level, are expected as construction proceeds.

Georgia Power is required to file semi-annual VCM reports with the Georgia PSC by February 28 and August 31 each year. On February 19, 2013, the Georgia PSC voted to approve Georgia Power's seventh VCM report, including construction capital costs incurred through June 30, 2012 of approximately $2.0 billion. Georgia Power's eighth VCM report requests approval for an additional $0.2 billion of construction capital costs incurred through December 31, 2012. If the projected certified construction capital costs to be borne by Georgia Power increase by 5% or the projected in-service dates are significantly extended, Georgia Power is required to seek an amendment to the Plant Vogtle Units 3 and 4 certificate from the Georgia PSC. Accordingly, the eighth VCM also requests an amendment to the certificate to increase the estimated in-service capital cost of Plant Vogtle Units 3 and 4 to $4.8 billion and to extend the estimated in-service dates to the fourth quarter 2017 and the fourth quarter 2018 for Plant Vogtle Units 3 and 4, respectively. Associated financing costs during the construction period are estimated to total approximately $2.0 billion. The Georgia PSC is expected to vote on the eighth VCM by October 2013.

In July 2012, the Owners and the Contractor began negotiations regarding the costs associated with design changes to the DCD and the delays in the timing of approval of the DCD and issuance of the COLs, including the assertion by the Contractor that the Owners are responsible for these costs under the terms of the Vogtle 3 and 4 Agreement. The Contractor has claimed that its estimated adjustment attributable to Georgia Power (based on Georgia Power's ownership interest) is approximately $425 million (in 2008 dollars) with respect to these issues. The Contractor also has asserted it is entitled to further schedule extensions. Georgia Power has not agreed with either the proposed cost or schedule adjustments or that the Owners have any responsibility for costs related to these issues. In November 2012, Georgia Power and the other Owners filed suit against the Contractor in the U.S. District Court for the Southern District of Georgia seeking a declaratory judgment that the Owners are not responsible for these costs. Also in November 2012, the Contractor filed suit against Georgia Power and the other Owners in the U.S. District Court for the District of Columbia alleging the Owners are responsible for these costs. While litigation has commenced and Georgia Power intends to vigorously defend its positions, Georgia Power expects negotiations with the Contractor to continue with respect to cost and schedule during which negotiations the parties may reach a mutually acceptable compromise of their positions.

In addition, processes are in place that are designed to assure compliance with the requirements specified in the DCD and the COLs, including rigorous inspections by Southern Nuclear and the NRC that occur throughout construction. During the fourth quarter 2012, certain details of the rebar design for the Plant Vogtle Unit 3 nuclear island were evaluated for consistency with the DCD and deviations were identified. On February 26, 2013 and March 1, 2013, the NRC approved the two license amendment requests required to conform the rebar design details to NRC requirements and, on March 14, 2013, the placement of basemat structural concrete for the nuclear island of Plant Vogtle Unit 3 was completed. Additional license amendment requests are pending before the NRC. Various design and other issues are expected to arise as construction proceeds, which may result in additional license amendments or require other resolution. If any license amendment requests are not resolved in a timely manner, there may be delays in the project schedule that could result in increased costs either to the Owners, the Contractor, or both.

As construction continues, additional delays in the fabrication and assembly of structural modules, the failure of such modules to meet applicable standards, or other issues may further impact project schedule and cost. Additional claims by the Contractor or Georgia Power (on behalf of the Owners) are also likely to arise throughout construction. These claims may be resolved through formal and informal dispute resolution procedures under the Vogtle 3 and 4 Agreement, but also may be resolved through litigation.

The ultimate outcome of these matters cannot be determined at this time.

Gulf Power

Retail Base Rate Case

See Note 3 to the financial statements of Gulf Power under "Retail Regulatory Matters – Retail Base Rate Case" in Item 8 of the Form 10-K for additional information.

On May 9, 2013, in accordance with the Florida Administrative Code Rules, Gulf Power notified the Florida PSC of Gulf Power's intent to file for an increase in Gulf Power's base rates, not sooner than July 8, 2013 (60 days after the notification) and not later than July 22, 2013. Gulf Power is proposing the projected 12 months ending December 31, 2014 as the test year for the anticipated rate case filing. The proposed test year is a calendar year that corresponds to Gulf Power's fiscal year and largely corresponds with the first fiscal period that new, permanent rates could be in effect. Gulf Power currently estimates that an increase in annual revenues between $75 million and $80 million will be requested. The ultimate outcome of this matter cannot be determined at this time.

Cost Recovery Clauses

See Note 3 to the financial statements of Gulf Power under "Retail Regulatory Matters – Cost Recovery Clauses" in Item 8 of the Form 10-K for additional information.

Fuel Cost Recovery

See Notes 1 and 3 to the financial statements of Gulf Power under "Revenues" and "Retail Regulatory Matters – Cost Recovery Clauses – Fuel Cost Recovery," respectively, in Item 8 of the Form 10-K for additional information.

Over recovered fuel costs at March 31, 2013 totaled $5.1 million compared to $17.1 million at December 31, 2012. These amounts are included in other regulatory liabilities, current on Gulf Power's Condensed Balance Sheets herein.

Purchased Power Capacity Recovery

See Notes 1 and 3 to the financial statements of Gulf Power under "Revenues" and "Retail Regulatory Matters – Cost Recovery Clauses – Purchased Power Capacity Recovery," respectively, in Item 8 of the Form 10-K for additional information.

At March 31, 2013 the over recovered purchased power capacity costs totaled $1.8 million, which is included in other regulatory liabilities, current on Gulf Power's Condensed Balance Sheets herein. At December 31, 2012, the under recovered purchased power capacity costs totaled $0.8 million, which is included in under recovered regulatory clause revenues on Gulf Power's Condensed Balance Sheets herein.

Environmental Cost Recovery

See Note 3 to the financial statements of Gulf Power under "Retail Regulatory Matters – Cost Recovery Clauses – Environmental Cost Recovery" in Item 8 of the Form 10-K for additional information.

Under recovered environmental costs at March 31, 2013 totaled $8.9 million compared to $1.9 million at December 31, 2012. These amounts are included in under recovered regulatory clause revenues on Gulf Power's Condensed Balance Sheets herein.

Energy Conservation Cost Recovery

See Note 3 to the financial statements of Gulf Power under "Retail Regulatory Matters – Cost Recovery Clauses – Energy Conservation Cost Recovery" in Item 8 of the Form 10-K for additional information.

Under recovered energy conservation costs at March 31, 2013 totaled $3.0 million compared to $0.8 million at December 31, 2012. These amounts are included in under recovered regulatory clause revenues on Gulf Power's Condensed Balance Sheets herein.

Mississippi Power

Performance Evaluation Plan

See Note 3 to the financial statements of Mississippi Power under "Retail Regulatory Matters – Performance Evaluation Plan" in Item 8 of the Form 10-K/A for additional information regarding Mississippi Power's base rates.

On January 18, 2013, Mississippi Power filed its annual PEP filing for 2013, which indicated a rate increase of 1.990%, or $15.8 million, annually. On March 4, 2013, Mississippi Power and the Mississippi Public Utilities Staff (MPUS) filed a joint stipulation which revised the annual PEP filing for 2013 to reflect the removal of certain costs related to unresolved matters that are currently under review. On March 5, 2013, the revised annual PEP filing for 2013 was approved by the Mississippi PSC, which resulted in a rate increase of 1.925%, or $15.3 million, annually, with the new rates effective March 19, 2013. Mississippi Power may be entitled to $3.3 million in additional revenues in 2013 as a result of the late implementation of the 2013 PEP rate increase.

On March 15, 2013, Mississippi Power submitted its annual PEP lookback filing for 2012, which indicated a refund due to customers of $4.7 million, which was accrued in retail revenues. On May 1, 2013, the MPUS contested the filing.

The ultimate outcome of these matters cannot be determined at this time.

Environmental Compliance Overview Plan

See Note 3 to the financial statements of Mississippi Power under "Retail Regulatory Matters – Environmental Compliance Overview Plan" in Item 8 of the Form 10-K/A for information on Mississippi Power's annual environmental filing with the Mississippi PSC.

In April 2012, the Mississippi PSC approved Mississippi Power's request for a CPCN to construct a flue gas desulfurization system (scrubber) on Plant Daniel Units 1 and 2. In May 2012, the Sierra Club filed a notice of appeal of the order with the Chancery Court of Harrison County, Mississippi (Chancery Court). These units are jointly owned by Mississippi Power and Gulf Power, with 50% ownership each. The estimated total cost of the project is approximately $660 million, with Mississippi Power's portion being $330 million, excluding AFUDC. The project is scheduled for completion in December 2015. Mississippi Power's portion of the cost is expected to be recovered through the ECO Plan. As of March 31, 2013, total project expenditures were $183.2 million, with Mississippi Power's portion being $91.6 million. The ultimate outcome of this matter cannot be determined at this time.

Fuel Cost Recovery

See Note 3 to the financial statements of Mississippi Power under "Retail Regulatory Matters – Fuel Cost Recovery" in Item 8 of the Form 10-K/A for information regarding Mississippi Power's fuel cost recovery.

On January 18, 2013, in compliance with Mississippi Power's filing requirement, Mississippi Power requested an annual adjustment of the retail fuel cost recovery factor in an amount equal to a decrease of 4.7%, or $35.5 million, of total 2012 retail revenue. The Mississippi PSC approved the retail fuel cost recovery factor on March 5, 2013, with the new rates effective March 19, 2013.

At March 31, 2013, the amount of over recovered retail fuel costs included on Mississippi Power's Condensed Balance Sheets herein was $60.9 million compared to $56.6 million at December 31, 2012. Mississippi Power also has wholesale MRA and Market Based (MB) fuel cost recovery factors. At March 31, 2013, the amount of over recovered wholesale MRA and MB fuel costs included on Mississippi Power's Condensed Balance Sheets herein was $18.1 million and $1.7 million, respectively, compared to $19.0 million and $2.1 million, respectively, at December 31, 2012. In addition, at each of March 31, 2013 and December 31, 2012, the amount of under recovered MRA emissions allowance cost included on Mississippi Power's Condensed Balance Sheets herein was $0.4 million. Mississippi Power's operating revenues are adjusted for differences in actual recoverable fuel cost and amounts billed in accordance with the currently approved cost recovery rate. Accordingly, changes in the billing factor have no significant effect on Mississippi Power's revenues or net income, but will affect cash flow.

Storm Damage Cost Recovery

See Note 3 to the financial statements of Mississippi Power under "Retail Regulatory Matters – Storm Damage Cost Recovery" in Item 8 in the Form 10-K/A for information regarding Mississippi Power's storm damage cost recovery. Mississippi Power maintains a reserve to cover the cost of damage from major storms to its transmission and distribution facilities and generally the cost of uninsured damage to its generation facilities and other property. At March 31, 2013, the balance in the storm reserve was $57.2 million.

Integrated Coal Gasification Combined Cycle

See Note 3 to the financial statements of Southern Company under "Integrated Coal Gasification Combined Cycle" in Item 8 of the Form 10-K and Note 3 to the financial statements of Mississippi Power under "Integrated Coal Gasification Combined Cycle" in Item 8 of the Form 10-K/A for information regarding Mississippi Power's construction of the Kemper IGCC.

Kemper IGCC Project Approval

In 2010, the Mississippi PSC issued a CPCN authorizing the acquisition, construction, and operation of the Kemper IGCC (2010 MPSC Order) located in Kemper County, Mississippi. The Sierra Club filed an appeal of the Mississippi PSC's issuance of the CPCN and, in March 2012, the Mississippi Supreme Court reversed the decision of the Chancery Court upholding the 2010 MPSC Order and remanded the matter to the Mississippi PSC. The

Mississippi Supreme Court concluded that the 2010 MPSC Order did not cite in sufficient detail substantial evidence upon which the Mississippi Supreme Court could determine the basis for the findings of the Mississippi PSC granting the CPCN. In April 2012, the Mississippi PSC issued a detailed order (2012 MPSC Order) confirming the CPCN for the Kemper IGCC, which the Sierra Club appealed to the Chancery Court. In December 2012, the Chancery Court affirmed the 2012 MPSC Order which confirmed the issuance of the CPCN for the Kemper IGCC. On January 8, 2013, the Sierra Club filed an appeal of the Chancery Court's ruling with the Mississippi Supreme Court.

The Kemper IGCC is currently under construction and will utilize an integrated coal gasification combined cycle technology with an output capacity of 582 MWs. The Kemper IGCC will be fueled by locally mined lignite (an abundant, lower heating value coal) from a mine owned by Mississippi Power and situated adjacent to the Kemper IGCC that is scheduled to begin operations in June 2013. In connection with the Kemper IGCC, Mississippi Power also is constructing and plans to operate approximately 61 miles of carbon dioxide (CO_2) pipeline infrastructure. The Kemper IGCC and the CO_2 pipeline are scheduled to be placed in service in May 2014. See Note 3 to the financial statements of Southern Company under "Integrated Coal Gasification Combined Cycle – Lignite Mine and CO_2 Pipeline Facilities" in Item 8 of the Form 10-K and Note 3 to the financial statements of Mississippi Power under "Integrated Coal Gasification Combined Cycle – Lignite Mine and CO_2 Pipeline Facilities" in Item 8 of the Form 10-K/A for additional information regarding the lignite mine and the CO_2 pipeline.

The ultimate outcome of the CPCN challenge cannot be determined at this time.

Kemper IGCC Cost Estimate

The certificated cost estimate of the Kemper IGCC included in the 2012 MPSC Order was $2.4 billion, net of $245 million of grants awarded to the project by the DOE under the Clean Coal Power Initiative Round 2 (DOE Grants), the cost of the lignite mine and equipment, the cost of the CO_2 pipeline facilities, and AFUDC related to the Kemper IGCC. The 2012 MPSC Order approved a construction cost cap of up to $2.88 billion, with recovery of prudently-incurred costs subject to approval by the Mississippi PSC. Exceptions to the $2.88 billion cost cap include the cost of the lignite mine and equipment, the cost of the CO_2 pipeline facilities, AFUDC, and certain general exceptions as contemplated in the Settlement Agreement (described below) and the 2012 MPSC Order, which includes change of law, force majeure, and beneficial capital (which exists when Mississippi Power demonstrates that the purpose and effect of the construction cost increase is to produce efficiencies that will result in a neutral or favorable effect on customers, relative to the original proposal for the CPCN) (Cost Cap Exceptions). Recovery of the Cost Cap Exception amounts remains subject to review and approval by the Mississippi PSC.

On April 23, 2013, Mississippi Power revised its cost estimate for the Kemper IGCC to approximately $3.42 billion, net of the DOE Grants and the Cost Cap Exceptions. Estimated amounts of the Cost Cap Exceptions include $245 million for the lignite mine and equipment, $132 million for the CO_2 pipeline facilities, $324 million of AFUDC, and $102 million of other general exceptions. The revised cost estimate reflects additional cost pressures, including labor costs, piping and other material costs, engineering and support costs, and productivity decreases. Mississippi Power does not intend to seek any joint owner contributions or rate recovery for any costs of the Kemper IGCC that exceed the $2.88 billion cost cap, except for amounts subject to the Cost Cap Exceptions.

As a result of an evaluation of the revised cost estimate, Mississippi Power determined that a portion of this $540 million estimated probable loss related to the period ended December 31, 2012. Accordingly, Mississippi Power restated its 2012 financial statements to reflect a pre-tax charge to income for this estimated probable loss of $78.0 million ($48.2 million after tax) in 2012, with the additional $462.0 million ($285.3 million after tax) reflected in the first quarter 2013. Southern Company evaluated the portion of the estimated probable loss related to 2012 and concluded it was not material to Southern Company. Therefore, Southern Company reflected the total pre-tax charge to income for this estimated probable loss of $540.0 million ($333.5 million after tax) in the first quarter 2013.

Southern Company's and Mississippi Power's analysis of the estimated cost to complete the Kemper IGCC will be ongoing throughout the construction period. It is possible that Mississippi Power could experience further cost increases and/or schedule delays with respect to the Kemper IGCC as a result of factors including, but not limited to, costs and productivity of labor, adverse weather conditions, shortages and inconsistent quality of equipment, materials, and labor, contractor or supplier delay or non-performance under construction or other agreements, delays

associated with start-up activities, and/or unforeseen engineering problems. In subsequent periods, any changes in the estimated costs to complete construction of the Kemper IGCC subject to the $2.88 billion cost cap will be reflected in Southern Company's and Mississippi Power's statements of income and these changes could be material.

As of March 31, 2013, Mississippi Power had spent a total of $2.88 billion on the Kemper IGCC, excluding the estimated probable loss. These costs include $2.41 billion for the portion of the Kemper IGCC subject to the construction cost cap, $188.9 million for the lignite mine and equipment, $84.4 million for the CO_2 pipeline facilities, $156.4 million of AFUDC, and $43.1 million of other costs, including certain general exceptions and certain regulatory assets. Of this total, $2.29 billion was included in CWIP (which is net of the DOE Grants and an estimated probable loss of $540 million), $43.4 million in other regulatory assets, $3.8 million in other deferred charges and assets on Southern Company's and Mississippi Power's Condensed Balance Sheets herein, and $1.0 million was previously expensed. Consistent with the treatment of non-capital costs incurred during the pre-construction period, the Mississippi PSC granted Mississippi Power the authority to defer all non-capital Kemper IGCC-related costs to a regulatory asset during the construction period. This includes deferred costs associated with the generation resource planning, evaluation, and screening activities. The amortization period for the regulatory asset will be determined by the Mississippi PSC at a later date. In addition, Mississippi Power is authorized to accrue carrying costs on the unamortized balance of such regulatory assets at a rate and in a manner to be determined by the Mississippi PSC in future cost recovery mechanism proceedings.

The ultimate outcome of these matters cannot be determined at this time.

Rate Recovery of Kemper IGCC Costs

See "FERC Matters" for additional information regarding Mississippi Power's MRA cost-based tariff relating to recovery of a portion of the Kemper IGCC costs from Mississippi Power's wholesale customers. Rate recovery of the retail portion of the Kemper IGCC is subject to the jurisdiction of the Mississippi PSC. See "Baseload Act" herein for additional information.

On January 24, 2013, Mississippi Power entered into a settlement agreement (Settlement Agreement) with the Mississippi PSC that, among other things, establishes the process for resolving matters regarding cost recovery related to the Kemper IGCC. Under the Settlement Agreement, Mississippi Power agreed to limit the portion of prudently-incurred Kemper IGCC costs to be included in retail rate base to the $2.4 billion certificated cost estimate, plus the Cost Cap Exceptions as well as any other costs permitted or determined to be excluded from the $2.88 billion cost cap by the Mississippi PSC. Mississippi Power intends to finance (1) prudently-incurred costs in excess of the certificated cost estimate and up to the $2.88 billion cost cap, net of the DOE Grants and the Cost Cap Exceptions, (2) the accrued AFUDC, and (3) exceptions not provided for in the Seven-Year Rate Plan (discussed below) through securitization as provided in State of Mississippi legislation. The rate recovery necessary to recover the annual costs of securitization is expected to be filed and become effective after the Kemper IGCC is placed in service and following completion of the Mississippi PSC's final prudence review of costs for the Kemper IGCC.

Under the terms of the Settlement Agreement, Mississippi Power and the Mississippi PSC agreed to follow certain regulatory procedures and schedules for resolving the cost recovery matters related to the Kemper IGCC. These procedures and schedules include the following: (1) Mississippi Power's filing on January 25, 2013 of a new request to increase retail rates in 2013 by $172 million annually, based on projected investment for 2013, to be recorded to a regulatory liability to be used to mitigate rate impacts when the Kemper IGCC is placed in service; (2) the Mississippi PSC's decision on that matter on March 5, 2013 as described below; (3) Mississippi Power's collaboration with the MPUS to file with the Mississippi PSC within three months of the Settlement Agreement a rate recovery plan for the Kemper IGCC for the first seven years of its operation, along with a proposed revenue requirement under such plan for 2014 through 2020 (Seven-Year Rate Plan) (which was made on February 26, 2013 and updated on March 22, 2013 as described below); (4) the Mississippi PSC's decision on the Seven-Year Rate Plan within four months of that filing (which is now expected to occur in the fall of 2013); (5) Mississippi Power's agreement to limit the portion of prudently-incurred Kemper IGCC costs to be included in rate base to the $2.4 billion certificated cost estimate, plus the Cost Cap Exceptions, excluding AFUDC, provided that this limitation will not prevent Mississippi Power from securing alternate financing to recover any prudently-incurred Kemper IGCC costs, including plant costs above the $2.4 billion certificated cost estimate and AFUDC, not otherwise recovered in

any Mississippi PSC rate proceeding contemplated by the Settlement Agreement; and (6) the Mississippi PSC's completion of its prudence review of the Kemper IGCC costs incurred through 2012 within six months of the Settlement Agreement, an additional prudence review upon considering the Seven-Year Rate Plan for costs incurred through the most recent reporting period, and a final prudence review of the remaining project costs within six months of the Kemper IGCC's in-service date. The Settlement Agreement provides that Mississippi Power may terminate the agreement if certain conditions are not met, if Mississippi Power is unable to secure alternate financing for any prudently-incurred Kemper IGCC costs not otherwise recovered in any Mississippi PSC rate proceeding contemplated by the Settlement Agreement, or if the Mississippi PSC fails to comply with the requirements of the Settlement Agreement. Legislation to authorize a multi-year rate plan and legislation to provide for alternate financing through securitization was enacted into law on February 26, 2013. Mississippi Power is currently working with the Mississippi PSC and the MPUS to implement the procedural schedules set forth in the Settlement Agreement and variations to the schedule are likely.

On March 5, 2013, the Mississippi PSC issued an order (2013 Kemper IGCC Order) approving a 15% increase in retail rates effective on March 19, 2013, and an additional 3% increase in retail rates effective January 1, 2014, which collectively are designed to collect $156 million annually beginning in 2014. All amounts collected through April 2014, which are expected to total $126 million, will be recorded as a regulatory liability to be used to mitigate rate impacts beginning in May 2014 when the Kemper IGCC is expected to be placed in service. On March 21, 2013, a legal challenge to the 2013 Kemper IGCC Order was filed with the Mississippi Supreme Court.

Because the 2013 Kemper IGCC Order did not provide for the inclusion of CWIP in rate base as permitted by the Baseload Act described below, Mississippi Power continues to record AFUDC on the Kemper IGCC during the construction period. Mississippi Power will not record AFUDC on any additional costs of the Kemper IGCC that exceed the $2.88 billion cost cap, except for Cost Cap Exception amounts. Mississippi Power's rate plans filed pursuant to the Settlement Agreement contemplate the continued accrual of AFUDC through the May 2014 expected in-service date.

On March 22, 2013, Mississippi Power, in compliance with the 2013 Kemper IGCC Order, filed a revision to the Seven-Year Rate Plan with the Mississippi PSC for the Kemper IGCC for 2014 through 2020, the first seven years of operation of the Kemper IGCC. The Seven-Year Rate Plan, which contemplates Mississippi Power's sale of a 15% undivided ownership interest in the Kemper IGCC, proposes recovery of an annual revenue requirement of approximately $156 million of Kemper IGCC-related operational costs and rate base amounts, including plant costs equal to the $2.4 billion certificated cost estimate. The 2013 Kemper IGCC Order, which increased rates beginning on March 19, 2013, is integral to the Seven-Year Rate Plan, which contemplates amortization of the April 2014 regulatory liability balance to be used to mitigate rate impacts from the expected in-service date of May 2014 through 2020, based on a fixed amortization schedule that requires approval by the Mississippi PSC. Under the Seven-Year Rate Plan filing, Mississippi Power proposes annual rate recovery to remain the same from 2014 through 2020. While it is the intent of Mississippi Power for the actual revenue requirement to equal the proposed revenue requirement, Mississippi Power proposes that the annual differences through 2020 for certain items contemplated in the Seven-Year Rate Plan will be deferred, subject to accrual of carrying costs, and the cumulative balance will be reviewed at the end of the term of the Settlement Agreement by the Mississippi PSC to determine the disposition of any potential remaining deferred balance.

The revenue requirements set forth in Mississippi Power's Seven-Year Rate Plan described above assume, among other things, the Kemper IGCC will be placed in service in May 2014, the sale of a 15% undivided interest in the Kemper IGCC to SMEPA will be completed as described herein, Mississippi Power's receipt of the benefits relating to tax credits described herein, and recovery of the Cost Cap Exceptions described herein.

The ultimate outcome of these matters, including the determinations of prudency and the specific manner of recovery of costs relating to the Kemper IGCC, is subject to further regulatory actions and cannot be determined at this time.

Proposed Sale of Undivided Interest to SMEPA

In 2010, Mississippi Power and SMEPA entered into an asset purchase agreement whereby SMEPA agreed to purchase a 17.5% undivided interest in the Kemper IGCC. In February 2012, the Mississippi PSC approved the sale and transfer of 17.5% of the Kemper IGCC to SMEPA. In June 2012, Mississippi Power and SMEPA signed an amendment to the asset purchase agreement whereby SMEPA extended its option to purchase until December 31, 2012, and reduced its purchase commitment percentage from a 17.5% to a 15% undivided interest in the Kemper IGCC, subject to approval by the Mississippi PSC. On December 31, 2012, Mississippi Power and SMEPA agreed to extend SMEPA's option to purchase through December 31, 2013.

The closing of this transaction is conditioned upon execution of a joint ownership and operating agreement, receipt of all construction permits, appropriate regulatory approvals, financing, and other conditions. In September 2012, SMEPA received a conditional loan commitment from Rural Utilities Service to provide funding for SMEPA's undivided interest in the Kemper IGCC.

In March 2012, Mississippi Power received a $150 million interest-bearing refundable deposit from SMEPA to be applied to the purchase. While the expectation is that the amount will be applied to the purchase price at closing, Mississippi Power would be required to refund the deposit upon the termination of the asset purchase agreement, within 60 days of a request by SMEPA for a full or partial refund, or within 15 days at SMEPA's discretion in the event that Mississippi Power is assigned a senior unsecured credit rating of BBB+ or lower by S&P or Baa1 or lower by Moody's or ceases to be rated by either of these rating agencies. Given the interest-bearing nature of the deposit and SMEPA's ability to request a refund, the deposit has been presented as a current liability in Southern Company's and Mississippi Power's Condensed Balance Sheets herein and as financing proceeds in Southern Company's and Mississippi Power's Condensed Statements of Cash Flows herein.

The ultimate outcome of these matters cannot be determined at this time.

Baseload Act

In 2008, the Baseload Act was signed by the Governor of Mississippi and is designed to enhance the Mississippi PSC's authority to facilitate development and construction of base load generation in the State of Mississippi. The Baseload Act authorizes, but does not require, the Mississippi PSC to adopt a cost recovery mechanism that includes in retail base rates, prior to and during construction, all or a portion of the prudently-incurred pre-construction and construction costs incurred by a utility in constructing a base load electric generating plant. Prior to the passage of the Baseload Act, such costs would traditionally be recovered only after the plant was placed in service. The Baseload Act also provides for periodic prudence reviews by the Mississippi PSC and prohibits the cancellation of any such generating plant without the approval of the Mississippi PSC. In the event of cancellation of the construction of the plant without approval of the Mississippi PSC, the Baseload Act authorizes the Mississippi PSC to make a public interest determination as to whether and to what extent the utility will be afforded rate recovery for costs incurred in connection with such cancelled generating plant. There are legal challenges to the constitutionality of the Baseload Act currently pending before the Mississippi Supreme Court. The ultimate outcome of the legal challenges to this legislation cannot be determined at this time. See "Rate Recovery of Kemper IGCC Costs" herein for additional information.

Tax Incentives

The IRS has allocated $133 million (Phase I) and $279 million (Phase II) of Internal Revenue Code Section 48A tax credits to Mississippi Power in connection with the Kemper IGCC. Mississippi Power's utilization of Phase I and Phase II credits is dependent upon meeting the IRS certification requirements, including an in-service date no later than May 11, 2014 for the Phase I credits and April 19, 2016 for the Phase II credits. In order to remain eligible for the Phase II credits, Mississippi Power plans to capture and sequester (via enhanced oil recovery) at least 65% of the CO_2 produced by the Kemper IGCC during operations in accordance with the rules for Section 48A investment tax credits. Through March 31, 2013, Mississippi Power had received or accrued tax benefits totaling $412 million for these tax credits, which will be amortized as a reduction to depreciation and amortization over the life of the Kemper IGCC. As a result of bonus tax depreciation on certain assets placed, or to be placed, in service in 2012 and 2013, and the subsequent reduction in federal taxable income, Mississippi Power estimates that it will not be able to

utilize $178.8 million of these tax credits until after March 31, 2014. IRS guidelines allow these unused tax credits to be carried forward for 20 years from the date received, if not utilized before then. In October 2012, Mississippi Power filed an application with the DOE for certification of the Kemper IGCC for additional tax credits under the Internal Revenue Code Section 48A (Phase III).

A portion of the tax credits realized by Mississippi Power may be subject to recapture upon successful completion of SMEPA's purchase of an undivided interest in the Kemper IGCC as described above. In addition, all or a portion of the tax credits will be subject to recapture if Mississippi Power fails to satisfy the in-service date requirements and CO_2 capture requirements described above.

On January 2, 2013, the American Taxpayer Relief Act of 2012 (ATRA) was signed into law. The ATRA retroactively extended several tax credits through 2013 and 50% bonus depreciation for property to be placed in service in 2013 (and for certain long-term production-period projects to be placed in service in 2014), which is expected to apply to the Kemper IGCC.

The ultimate outcome of these matters cannot be determined at this time.

Other Matters

On April 4, 2013, an explosion occurred at Plant Bowen Unit 2 that resulted in substantial damage to the Plant Bowen Unit 2 generator, Plant Bowen's Units 1 and 2 control room and surrounding areas, as well as Plant Bowen's switchyard. The extent of the damage sustained by Plant Bowen Unit 1 is unknown. Plant Bowen Units 1 and 2 (approximately 1,400 MWs) remain offline, pending assessment of the damage and completion of repairs. Georgia Power expects that any material repair costs related to the damage will be covered by property insurance. The ultimate outcome of this matter cannot be determined at this time.

(C) FAIR VALUE MEASUREMENTS

As of March 31, 2013, assets and liabilities measured at fair value on a recurring basis during the period, together with the level of the fair value hierarchy in which they fall, were as follows:

	Fair Value Measurements Using			
As of March 31, 2013:	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Total**
		(in millions)		
Southern Company				
Assets:				
Energy-related derivatives	$ —	$ 50	$ —	$ 50
Interest rate derivatives	—	10	—	10
Nuclear decommissioning trusts[a]	526	838	—	1,364
Cash equivalents	223	—	—	223
Other investments	9	—	15	24
Total	$ 758	$ 898	$ 15	$ 1,671
Liabilities:				
Energy-related derivatives	$ —	$ 63	$ —	$ 63
Alabama Power				
Assets:				
Energy-related derivatives	$ —	$ 12	$ —	$ 12
Nuclear decommissioning trusts:[b]				
Domestic equity	320	69	—	389
Foreign equity	30	56	—	86
U.S. Treasury and government agency securities	—	29	—	29
Corporate bonds	—	101	—	101
Mortgage and asset backed securities	—	25	—	25
Other	—	10	—	10
Total	$ 350	$ 302	$ —	$ 652
Liabilities:				
Energy-related derivatives	$ —	$ 7	$ —	$ 7

As of March 31, 2013:	Fair Value Measurements Using: Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
		(in millions)		
Georgia Power				
Assets:				
Energy-related derivatives	$ —	$ 13	$ —	$ 13
Nuclear decommissioning trusts:[b] [c]				
Domestic equity	176	1	—	177
Foreign equity	—	120	—	120
U.S. Treasury and government agency securities	—	130	—	130
Municipal bonds	—	28	—	28
Corporate bonds	—	130	—	130
Mortgage and asset backed securities	—	121	—	121
Other	—	18	—	18
Cash equivalents	27	—	—	27
Total	$ 203	$ 561	$ —	$ 764
Liabilities:				
Energy-related derivatives	$ —	$ 28	$ —	$ 28
Gulf Power				
Assets:				
Energy-related derivatives	$ —	$ 14	$ —	$ 14
Cash equivalents	16	—	—	16
Total	$ 16	$ 14	$ —	$ 30
Liabilities:				
Energy-related derivatives	$ —	$ 16	$ —	$ 16
Mississippi Power				
Assets:				
Energy-related derivatives	$ —	$ 6	$ —	$ 6
Cash equivalents	122	—	—	122
Total	$ 122	$ 6	$ —	$ 128
Liabilities:				
Energy-related derivatives	$ —	$ 11	$ —	$ 11
Southern Power				
Assets:				
Energy-related derivatives	$ —	$ 5	$ —	$ 5
Cash equivalents	27	—	—	27
Total	$ 27	$ 5	$ —	$ 32
Liabilities:				
Energy-related derivatives	$ —	$ 1	$ —	$ 1

(a) For additional detail, see the nuclear decommissioning trusts sections for Alabama Power and Georgia Power in this table.
(b) Excludes receivables related to investment income, pending investment sales, and payables related to pending investment purchases.

(c) Includes the investment securities pledged to creditors and cash collateral received and excludes payables related to the securities lending program. As of March 31, 2013, approximately $68 million of the fair market value of Georgia Power's nuclear decommissioning trust funds' securities were on loan and pledged to creditors under the funds' managers' securities lending program.

Valuation Methodologies

The energy-related derivatives primarily consist of over-the-counter financial products for natural gas and physical power products including, from time to time, basis swaps. These are standard products used within the energy industry and are valued using the market approach. The inputs used are mainly from observable market sources, such as forward natural gas prices, power prices, implied volatility, and LIBOR interest rates. Interest rate and foreign currency derivatives are also standard over-the-counter financial products valued using the market approach. Inputs for interest rate derivatives include LIBOR interest rates, interest rate futures contracts, and occasionally implied volatility of interest rate options. Inputs for foreign currency derivatives are from observable market sources. See Note (H) herein for additional information on how these derivatives are used.

"Other investments" include investments in funds that are valued using the market approach and income approach. Securities that are traded in the open market are valued at the closing price on their principal exchange as of the measurement date. Discounts are applied in accordance with GAAP when certain trading restrictions exist. For investments that are not traded in the open market, the price paid will have been determined based on market factors including comparable multiples and the expectations regarding cash flows and business plan execution. As the investments mature or if market conditions change materially, further analysis of the fair market value of the investment is performed. This analysis is typically based on a metric, such as multiple of earnings, revenues, earnings before interest and income taxes, or earnings adjusted for certain cash changes. These multiples are based on comparable multiples for publicly traded companies or other relevant prior transactions.

For fair value measurements of investments within the nuclear decommissioning trusts and rabbi trust funds, specifically the fixed income assets using significant other observable inputs and unobservable inputs, the primary valuation technique used is the market approach. External pricing vendors are designated for each of the asset classes in the nuclear decommissioning trusts and rabbi trust funds with each security discriminately assigned a primary pricing source, based on similar characteristics.

A market price secured from the primary source vendor is then evaluated by management in its valuation of the assets within the trusts. As a general approach, market pricing vendors gather market data (including indices and market research reports) and integrate relative credit information, observed market movements, and sector news into proprietary pricing models, pricing systems, and mathematical tools. Dealer quotes and other market information including live trading levels and pricing analysts' judgment are also obtained when available.

As of March 31, 2013, the fair value measurements of investments calculated at net asset value per share (or its equivalent), as well as the nature and risks of those investments, were as follows:

As of March 31, 2013:	Fair Value	Unfunded Commitments	Redemption Frequency	Redemption Notice Period
	(in millions)			
Southern Company				
Nuclear decommissioning trusts:				
Foreign equity funds	$ 120	None	Monthly	5 days
Corporate bonds - commingled funds	7	None	Daily	1 to 3 days
Other - commingled funds	74	None	Daily/Monthly	Daily/7 days
Trust-owned life insurance	100	None	Daily	15 days
Cash equivalents:				
Money market funds	223	None	Daily	Not applicable
Alabama Power				
Nuclear decommissioning trusts:				
Other - commingled funds	56	None	Daily/Monthly	Daily/7 days
Trust-owned life insurance	100	None	Daily	15 days
Georgia Power				
Nuclear decommissioning trusts:				
Foreign equity funds	120	None	Monthly	5 days
Corporate bonds - commingled funds	7	None	Daily	Not applicable
Other - commingled funds	18	None	Daily	Not applicable
Cash equivalents:				
Money market funds	27	None	Daily	Not applicable
Gulf Power				
Cash equivalents:				
Money market funds	16	None	Daily	Not applicable
Mississippi Power				
Cash equivalents:				
Money market funds	122	None	Daily	Not applicable
Southern Power				
Cash equivalents:				
Money market funds	27	None	Daily	Not applicable

The NRC requires licensees of commissioned nuclear power reactors to establish a plan for providing reasonable assurance of funds for future decommissioning. Alabama Power and Georgia Power have external trust funds (the Funds) to comply with the NRC's regulations. The foreign equity fund in Georgia Power's nuclear decommissioning trusts seeks to provide long-term capital appreciation. In pursuing this investment objective, the foreign equity fund primarily invests in a diversified portfolio of equity securities of foreign companies, including those in emerging markets. These equity securities may include, but are not limited to, common stocks, preferred stocks, real estate investment trusts, convertible securities and depository receipts, including American depositary receipts, European depositary receipts and global depository receipts, and rights and warrants to buy common stocks. Georgia Power may withdraw all or a portion of its investment on the last business day of each month subject to a minimum withdrawal of $1 million, provided that a minimum investment of $10 million remains. If notices of withdrawal exceed 20% of the aggregate value of the foreign equity fund, then the foreign equity fund's board may refuse to permit the withdrawal of all such investments and may scale down the amounts to be withdrawn pro rata and may further determine that any withdrawal that has been postponed will have priority on the subsequent withdrawal date.

The commingled funds in Georgia Power's nuclear decommissioning trusts are invested primarily in a diversified portfolio, including, but not limited to, commercial paper, notes, repurchase agreements, and other evidences of

indebtedness with a maturity not exceeding 13 months from the date of purchase. The commingled funds will, however, generally maintain a dollar-weighted average portfolio maturity of 90 days or less. The assets may be longer term investment grade fixed income obligations with maturity shortening provisions. The primary objective for the commingled funds is a high level of current income consistent with stability of principal and liquidity. The commingled funds included with corporate bonds represent the investment of cash collateral received under the Funds' managers' securities lending program that can only be sold upon the return of the loaned securities. See Note 1 to the financial statements of Southern Company and Georgia Power under "Nuclear Decommissioning" in Item 8 of the Form 10-K for additional information.

Alabama Power's nuclear decommissioning trust includes investments in Trust-Owned Life Insurance (TOLI). The taxable nuclear decommissioning trust invests in the TOLI in order to minimize the impact of taxes on the portfolio and can draw on the value of the TOLI through death proceeds, loans against the cash surrender value, and/or the cash surrender value, subject to legal restrictions. The amounts reported in the table above reflect the fair value of investments the insurer has made in relation to the TOLI agreements. The nuclear decommissioning trust does not own the underlying investments, but the fair value of the investments approximates the cash surrender value of the TOLI policies. The investments made by the insurer are in commingled funds. The commingled funds primarily include investments in domestic and international equity securities and predominantly high-quality fixed income securities. These fixed income securities may include U.S. Treasury and government agency fixed income securities, non-U.S. government and agency fixed income securities, domestic and foreign corporate fixed income securities, and, to some degree, mortgage and asset backed securities. The passively managed funds seek to replicate the performance of a related index. The actively managed funds seek to exceed the performance of a related index through security analysis and selection.

Southern Company, Alabama Power, and Georgia Power continue to elect the option to fair value investment securities held in the nuclear decommissioning trust funds. For the three months ended March 31, 2013, the fair value of the funds, including reinvested interest and dividends reduced by the funds' expenses, increased by $59 million at Southern Company. Alabama Power recorded an increase in fair value of $38 million as an increase in regulatory liabilities. Georgia Power recorded an increase in fair value of $21 million as a reduction of its regulatory asset related to its asset retirement obligations.

The money market funds are short-term investments of excess funds in various money market mutual funds, which are portfolios of short-term debt securities. The money market funds are regulated by the SEC and typically receive the highest rating from credit rating agencies. Regulatory and rating agency requirements for money market funds include minimum credit ratings and maximum maturities for individual securities and a maximum weighted average portfolio maturity. Redemptions are available on a same day basis up to the full amount of the investment in the money market funds.

As of March 31, 2013, other financial instruments for which the carrying amount did not equal fair value were as follows:

	Carrying Amount	Fair Value
	(in millions)	
Long-term debt:		
Southern Company	$ 21,915	$ 23,644
Alabama Power	$ 6,179	$ 6,853
Georgia Power	$ 9,639	$ 10,316
Gulf Power	$ 1,246	$ 1,353
Mississippi Power	$ 2,211	$ 2,294
Southern Power	$ 1,308	$ 1,448

The fair values are determined using Level 2 measurements and are based on quoted market prices for the same or similar issues or on the current rates offered to Southern Company, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, and Southern Power.

(D) STOCKHOLDERS' EQUITY

Earnings per Share

For Southern Company, the only difference in computing basic and diluted earnings per share is attributable to awards outstanding under the stock option and performance share plans. See Note 8 to the financial statements of Southern Company in Item 8 of the Form 10-K for information on the stock option and performance share plans. The effects of both stock options and performance share award units were determined using the treasury stock method. Shares used to compute diluted earnings per share were as follows:

	Three Months Ended March 31, 2013	Three Months Ended March 31, 2012
	(in millions)	
As reported shares	**870**	868
Effect of options and performance share award units	**5**	9
Diluted shares	**875**	877

Stock options and performance share award units that were not included in the diluted earnings per share calculation because they were anti-dilutive were immaterial for the three months ended March 31, 2013 and 2012.

Changes in Stockholders' Equity

The following table presents year-to-date changes in stockholders' equity of Southern Company:

	Number of Common Shares				
	Issued	**Treasury**	**Common Stockholders' Equity**	**Preferred and Preference Stock of Subsidiaries**	**Total Stockholders' Equity**
	(in thousands)		*(in millions)*		
Balance at December 31, 2012	877,803	(10,035)	$ 18,297	$ 707	$ 19,004
Net income after dividends on preferred and preference stock	—	—	81	—	81
Other comprehensive income (loss)	—	—	4	—	4
Stock issued	2,638	—	99	—	99
Stock repurchased, at cost	—	—	(18)	—	(18)
Cash dividends on common stock	—	—	(426)	—	(426)
Other	—	(15)	—	—	—
Balance at March 31, 2013	**880,441**	**(10,050)**	**$ 18,037**	**$ 707**	**$ 18,744**
Balance at December 31, 2011	865,664	(539)	$ 17,578	$ 707	$ 18,285
Net income after dividends on preferred and preference stock	—	—	368	—	368
Other comprehensive income (loss)	—	—	6	—	6
Stock issued	3,571	—	157	—	157
Cash dividends on common stock	—	—	(410)	—	(410)
Other	—	(6)	—	—	—
Balance at March 31, 2012	869,235	(545)	$ 17,699	$ 707	$ 18,406

In July 2012, Southern Company announced a program to repurchase shares to partially offset the incremental shares issued under its employee and director stock plans. As of December 31, 2012, Southern Company had repurchased a total of approximately 9 million shares at a total cost of $430 million. There were no repurchases

under this program in the first quarter 2013. Pursuant to approval by the Southern Company Board of Directors, Southern Company may repurchase shares through open market purchases or privately negotiated transactions, in accordance with applicable securities laws.

(E) FINANCING

Bank Credit Arrangements

Bank credit arrangements provide liquidity support to the registrants' commercial paper borrowings and the traditional operating companies' variable rate pollution control revenue bonds. See Note 6 to the financial statements of each registrant (other than Mississippi Power) under "Bank Credit Arrangements" in Item 8 of the Form 10-K and Note 6 to the financial statements of Mississippi Power under "Bank Credit Arrangements" in Item 8 of the Form 10-K/A for additional information.

The following table outlines the committed credit arrangements by company as of March 31, 2013:

	Expires[a]						Executable Term Loans		Due Within One Year	
Company	2013	2014	2016	2018	Total	Unused	One Year	Two Years	Term Out	No Term Out
	(in millions)				*(in millions)*		*(in millions)*		*(in millions)*	
Southern Company	$ —	$ —	$ —	$ 1,000	$ 1,000	$ 1,000	$ —	$ —	$ —	$ —
Alabama Power	156	151	—	1,000	1,307	1,307	56	—	56	102
Georgia Power	—	—	150	1,600	1,750	1,740	—	—	—	—
Gulf Power	45	60	165	—	270	270	45	—	45	30
Mississippi Power	110	25	165	—	300	300	25	40	65	70
Southern Power	—	—	—	500	500	500	—	—	—	—
Other	50	—	—	—	50	50	25	—	25	25
Total	$ 361	$ 236	$ 480	$ 4,100	$ 5,177	$ 5,167	$ 151	$ 40	$ 191	$ 227

(a) No credit arrangements expire in 2015 or 2017.

In February 2013, Southern Company, Alabama Power, Georgia Power, and Southern Power each amended their multi-year credit arrangements, which extended the maturity dates from 2016 to 2018.

In March 2013, Alabama Power amended a $200 million credit arrangement, which extended the maturity date from 2014 to 2018. In March 2013, Gulf Power also amended a $35 million credit arrangement, which reduced the amount to $30 million and extended the maturity date from 2013 to 2014. In addition, in March 2013, Georgia Power, Gulf Power, and Mississippi Power each amended certain of their credit arrangements, which extended the maturity dates from 2014 to 2016 and, in the case of Mississippi Power, also revised the definition of debt to exclude securitized debt relating to the Kemper IGCC for purposes of calculating the debt covenant under these credit arrangements. See Note (B) under "Integrated Coal Gasification Combined Cycle" herein for information regarding legislation related to the securitization of certain costs of the Kemper IGCC.

Subsequent to March 31, 2013, Gulf Power entered into a new credit arrangement for $5 million with a maturity date of 2014.

Also subsequent to March 31, 2013, SEGCO entered into two new $25 million credit arrangements with maturity dates of 2014.

Most of these arrangements contain covenants that limit debt levels and typically contain cross default provisions that are restricted only to the indebtedness of the individual company. Southern Company and its subsidiaries are currently in compliance with all such covenants.

(F) RETIREMENT BENEFITS

Southern Company has a defined benefit, trusteed, pension plan covering substantially all employees. The qualified pension plan is funded in accordance with requirements of the Employee Retirement Income Security Act of 1974, as amended. No mandatory contributions to the qualified pension plan are anticipated for the year ending December 31, 2013. Southern Company also provides certain defined benefit pension plans for a selected group of management and highly compensated employees. Benefits under these non-qualified pension plans are funded on a cash basis. In addition, Southern Company provides certain medical care and life insurance benefits for retired employees through other postretirement benefit plans. The traditional operating companies fund related other postretirement trusts to the extent required by their respective regulatory commissions.

See Note 2 to the financial statements of Southern Company, Alabama Power, Georgia Power, and Gulf Power in Item 8 of the Form 10-K and Note 2 to the financial statements of Mississippi Power in Item 8 of the Form 10-K/A for additional information.

Components of the net periodic benefit costs for the three months ended March 31, 2013 and 2012 were as follows:

Pension Plans	Southern Company	Alabama Power	Georgia Power	Gulf Power	Mississippi Power
			(in millions)		
Three Months Ended March 31, 2013					
Service cost	$ 58	$ 13	$ 17	$ 3	$ 3
Interest cost	97	23	34	4	5
Expected return on plan assets	(151)	(39)	(53)	(6)	(7)
Amortization:					
Prior service costs	7	2	3	—	—
Net (gain)/loss	50	13	19	2	2
Net cost	$ 61	$ 12	$ 20	$ 3	$ 3
Three Months Ended March 31, 2012					
Service cost	$ 50	$ 11	$ 15	$ 2	$ 2
Interest cost	98	23	35	4	5
Expected return on plan assets	(145)	(40)	(55)	(6)	(6)
Amortization:					
Prior service costs	7	2	3	—	—
Net (gain)/loss	24	6	8	1	1
Net cost	$ 34	$ 2	$ 6	$ 1	$ 2

Postretirement Benefits	Southern Company	Alabama Power	Georgia Power	Gulf Power	Mississippi Power
			(in millions)		
Three Months Ended March 31, 2013					
Service cost	$ 6	$ 2	$ 2	$ —	$ —
Interest cost	19	5	8	1	1
Expected return on plan assets	(14)	(6)	(6)	—	—
Amortization:					
Transition obligation	1	—	1	—	—
Prior service costs	1	1	—	—	—
Net (gain)/loss	3	—	2	—	—
Net cost	$ 16	$ 2	$ 7	$ 1	$ 1
Three Months Ended March 31, 2012					
Service cost	$ 5	$ 1	$ 1	$ —	$ —
Interest cost	21	5	9	1	1
Expected return on plan assets	(15)	(6)	(7)	—	—
Amortization:					
Transition obligation	2	1	2	—	—
Prior service costs	1	1	—	—	—
Net (gain)/loss	2	—	1	—	—
Net cost	$ 16	$ 2	$ 6	$ 1	$ 1

(G) EFFECTIVE TAX RATE AND UNRECOGNIZED TAX BENEFITS

Effective Tax Rate

See Note 5 to the financial statements of each registrant (other than Mississippi Power) in Item 8 of the Form 10-K and Note 5 to the financial statements of Mississippi Power in Item 8 of the Form 10-K/A for information on the effective income tax rate.

Southern Company

Southern Company's effective tax rate is typically lower than the statutory rate due to its employee stock plans' dividend deduction and non-taxable AFUDC equity.

Southern Company's effective tax rate was 24.5% for the three months ended March 31, 2013 compared to 34.2% for the corresponding period in 2012. The American Jobs Creation Act of 2004 created a tax deduction for a portion of income attributable to U.S. production activities as defined in Section 199 of the Internal Revenue Code (production activities deduction). The decrease was primarily due to an increase in non-taxable AFUDC equity primarily related to Mississippi Power's construction of the Kemper IGCC combined with lower net income. The decrease was partially offset by the recognition in 2012 of previously unrecognized tax benefits as a result of a settlement with the IRS related to the methodology used to calculate the production activities deduction.

Alabama Power

Alabama Power's effective tax rate was 39.2% for the three months ended March 31, 2013 compared to 38.3% for the corresponding period in 2012. The increase was primarily due to the recognition in 2012 of previously unrecognized tax benefits as a result of a settlement with the IRS related to the production activities deduction.

Georgia Power

Georgia Power's effective tax rate was 38.1% for the three months ended March 31, 2013 compared to 34.9% for the corresponding period in 2012. The increase was primarily due to an increase in non-deductible book depreciation, the recognition in 2012 of previously unrecognized tax benefits as a result of a settlement with the IRS related to the production activities deduction, and a decrease in non-taxable AFUDC equity.

Gulf Power

Gulf Power's effective tax rate was 37.6% for the three months ended March 31, 2013 compared to 34.6% for the corresponding period in 2012. The increase was primarily due to the recognition in 2012 of previously unrecognized tax benefits as a result of a settlement with the IRS related to the production activities deduction.

Mississippi Power

Mississippi Power's effective tax rate was (40.8)% for the three months ended March 31, 2013 compared to 24.7% for the corresponding period in 2012. The decrease was primarily due to a net loss for the current period and an increase in non-taxable AFUDC equity related to construction of the Kemper IGCC.

Southern Power

Southern Power's effective tax rate was 33.5% for the three months ended March 31, 2013 compared to 31.3% for the corresponding period in 2012. The increase was primarily due to the recognition in 2012 of previously unrecognized tax benefits as a result of a settlement with the IRS related to the production activities deduction.

Unrecognized Tax Benefits

Changes during 2013 for unrecognized tax benefits were as follows:

	Southern Company	Alabama Power	Georgia Power	Gulf Power	Mississippi Power	Southern Power
			(in millions)			
Unrecognized tax benefits as of December 31, 2012	$ 70	$ 31	$ 23	$ 5	$ 6	$ 3
Tax positions from current periods	3	1	1	—	—	—
Balance as of March 31, 2013	$ 73	$ 32	$ 24	$ 5	$ 6	$ 3

The tax positions from current periods relate primarily to the tax accounting method change for repairs-generation assets. See "Tax Method of Accounting for Property Related Expenditures" herein for additional information.

The impact on the effective tax rate, if recognized, was as follows:

	As of March 31, 2013	As of December 31, 2012
	Southern Company	
	(in millions)	
Tax positions impacting the effective tax rate	**$ 5**	$ 5
Tax positions not impacting the effective tax rate	**68**	65
Balance of unrecognized tax benefits	**$ 73**	$ 70

The tax positions impacting the effective tax rate primarily relate to state income tax credits. The tax positions not impacting the effective tax rate relate to the timing difference associated with the tax accounting method change for repairs-generation assets. See "Tax Method of Accounting for Property Related Expenditures" herein for additional information. These amounts are presented on a gross basis without considering the related federal or state income tax impact.

All of the registrants classify interest on tax uncertainties as interest expense. Accrued interest for unrecognized tax benefits at March 31, 2013 and December 31, 2012 was not material.

None of the registrants accrued any penalties on uncertain tax positions.

It is reasonably possible that the amount of the unrecognized tax benefits associated with a majority of the registrants' unrecognized tax positions will significantly increase or decrease within 12 months. The resolution of the tax accounting method change for repairs-generation assets, as well as the conclusion or settlement of state audits, could impact the balances significantly. At this time, an estimate of the range of reasonably possible outcomes cannot be determined.

Tax Method of Accounting for Property Related Expenditures

Southern Company submitted a tax accounting method change related to the deductibility of repair costs associated with its subsidiaries' generation, transmission, and distribution systems effective for the 2009 consolidated federal income tax return in 2010. In August 2011, the IRS issued a revenue procedure, which provides a safe harbor method of accounting that taxpayers may use to determine repair costs for transmission and distribution property. Consequently, Southern Company incorporated into its federal income tax returns changes that conform to the new regulations and reversed all unrecognized tax positions related to transmission and distribution property.

In December 2011, the IRS published regulations on the deduction and capitalization of expenditures related to tangible property that generally apply for tax years beginning on or after January 1, 2014. The utility industry anticipates more detailed guidance concerning these regulations. Additionally, on April 30, 2013, the IRS issued

Revenue Procedure 2013-24, which provides guidance for taxpayers related to the deductibility of repair costs associated with generation assets. Southern Company is currently reviewing this new guidance. Due to uncertainty regarding the ultimate resolution of the repair costs for generation assets, an unrecognized tax position was recorded for the tax accounting method change for repairs-generation assets. The ultimate outcome of these matters cannot be determined at this time; however, implementing these regulations is not expected to have a material impact on net income.

(H) DERIVATIVES

Southern Company, the traditional operating companies, and Southern Power are exposed to market risks, primarily commodity price risk, interest rate risk, and occasionally foreign currency risk. To manage the volatility attributable to these exposures, each company nets its exposures, where possible, to take advantage of natural offsets and enters into various derivative transactions for the remaining exposures pursuant to each company's policies in areas such as counterparty exposure and risk management practices. Each company's policy is that derivatives are to be used primarily for hedging purposes and mandates strict adherence to all applicable risk management policies. Derivative positions are monitored using techniques including, but not limited to, market valuation, value at risk, stress testing, and sensitivity analysis. Derivative instruments are recognized at fair value in the balance sheets as either assets or liabilities and are presented on a gross basis. In the statements of cash flows, the cash impacts of settled energy-related and interest rate derivatives are recorded as operating activities and the cash impacts of settled foreign currency derivatives are recorded as investing activities.

Energy-Related Derivatives

The traditional operating companies and Southern Power enter into energy-related derivatives to hedge exposures to electricity, gas, and other fuel price changes. However, due to cost-based rate regulations and other various cost recovery mechanisms, the traditional operating companies have limited exposure to market volatility in commodity fuel prices and prices of electricity. Each of the traditional operating companies manages fuel-hedging programs, implemented per the guidelines of their respective state PSCs, through the use of financial derivative contracts, which is expected to continue to mitigate price volatility. Southern Power has limited exposure to market volatility in commodity fuel prices and prices of electricity because its long-term sales contracts shift substantially all fuel cost responsibility to the purchaser. However, Southern Power has been and may continue to be exposed to market volatility in energy-related commodity prices as a result of sales of uncontracted generating capacity.

To mitigate residual risks relative to movements in electricity prices, the traditional operating companies and Southern Power may enter into physical fixed-price contracts for the purchase and sale of electricity through the wholesale electricity market. To mitigate residual risks relative to movements in gas prices, the traditional operating companies and Southern Power may enter into fixed-price contracts for natural gas purchases; however, a significant portion of contracts are priced at market.

Energy-related derivative contracts are accounted for under one of three methods:

- *Regulatory Hedges* — Energy-related derivative contracts which are designated as regulatory hedges relate primarily to the traditional operating companies' fuel hedging programs, where gains and losses are initially recorded as regulatory liabilities and assets, respectively, and then are included in fuel expense as the underlying fuel is used in operations and ultimately recovered through the respective fuel cost recovery clauses.
- *Cash Flow Hedges* — Gains and losses on energy-related derivatives designated as cash flow hedges which are mainly used to hedge anticipated purchases and sales and are initially deferred in OCI before being recognized in the statements of income in the same period as the hedged transactions are reflected in earnings.
- *Not Designated* — Gains and losses on energy-related derivative contracts that are not designated or fail to qualify as hedges are recognized in the statements of income as incurred.

Some energy-related derivative contracts require physical delivery as opposed to financial settlement, and this type of derivative is both common and prevalent within the electric industry. When an energy-related derivative contract

is settled physically, any cumulative unrealized gain or loss is reversed and the contract price is recognized in the respective line item representing the actual price of the underlying goods being delivered.

At March 31, 2013, the net volume of energy-related derivative contracts for natural gas positions for the Southern Company system, together with the longest hedge date over which the respective entity is hedging its exposure to the variability in future cash flows for forecasted transactions and the longest date for derivatives not designated as hedges, were as follows:

	Net Purchased mmBtu	Longest Hedge Date	Longest Non-Hedge Date
	(in millions)		
Southern Company	259	2017	2017
Alabama Power	58	2017	—
Georgia Power	90	2017	—
Gulf Power	70	2017	—
Mississippi Power	36	2017	—
Southern Power	5	—	2017

In addition to the volumes discussed in the above table, the traditional operating companies and Southern Power enter into physical natural gas supply contracts that provide the option to sell back excess gas due to operational constraints. The maximum expected volume of natural gas subject to such a feature is 11 million mmBtu for Southern Company, 1 million mmBtu for Alabama Power, 5 million mmBtu for Georgia Power, 1 million mmBtu for Gulf Power, 1 million mmBtu for Mississippi Power, and 3 million mmBtu for Southern Power.

For cash flow hedges, the amounts expected to be reclassified from AOCI to revenue and fuel expense for the next 12-month period ending March 31, 2014 are immaterial for all registrants.

Interest Rate Derivatives

Southern Company and certain subsidiaries may also enter into interest rate derivatives to hedge exposure to changes in interest rates. The derivatives employed as hedging instruments are structured to minimize ineffectiveness. Derivatives related to existing variable rate securities or forecasted transactions are accounted for as cash flow hedges where the effective portion of the derivatives' fair value gains or losses is recorded in OCI and is reclassified into earnings at the same time the hedged transactions affect earnings, with any ineffectiveness recorded directly to earnings. Derivatives related to existing fixed rate securities are accounted for as fair value hedges, where the derivatives' fair value gains or losses and hedged items' fair value gains or losses are both recorded directly to earnings, providing an offset, with any difference representing ineffectiveness.

At March 31, 2013, the following interest rate derivatives were outstanding:

	Notional Amount	Interest Rate Received	Interest Rate Paid	Hedge Maturity Date	Fair Value Gain (Loss) March 31, 2013
	(in millions)				*(in millions)*
Fair value hedges of existing debt					
Southern Company	$ 350	4.15%	3-month LIBOR + 1.96% [(a)]	May 2014	$ 10

(a) Weighted average

The following table reflects the estimated pre-tax gains (losses) that will be reclassified from AOCI to interest expense for the next 12-month period ending March 31, 2014, together with the longest date that total deferred gains and losses are expected to be amortized into earnings.

Registrant	Estimated Gain (Loss) to be Reclassified for the 12 Months Ending March 31, 2014	Total Deferred Gains (Losses) Amortized Through
	(in millions)	
Southern Company	$ (12)	2037
Alabama Power	(3)	2035
Georgia Power	(3)	2037
Gulf Power	(1)	2020
Mississippi Power	(1)	2022
Southern Power	(4)	2016

Foreign Currency Derivatives

Southern Company and certain subsidiaries may enter into foreign currency derivatives to hedge exposure to changes in foreign currency exchange rates arising from purchases of equipment denominated in a currency other than U.S. dollars. Derivatives related to a firm commitment in a foreign currency transaction are accounted for as fair value hedges where the derivatives' fair value gains or losses and the hedged items' fair value gains or losses are both recorded directly to earnings. Derivatives related to a forecasted transaction are accounted for as a cash flow hedge where the effective portion of the derivatives' fair value gains or losses is recorded in OCI and is reclassified into earnings at the same time the hedged transactions affect earnings. Any ineffectiveness is typically recorded directly to earnings; however, Mississippi Power has regulatory approval allowing it to defer any ineffectiveness associated with firm commitments related to the Kemper IGCC to a regulatory asset. The derivatives employed as hedging instruments are structured to minimize ineffectiveness. At March 31, 2013, the fair value of the foreign currency derivatives outstanding was immaterial.

Derivative Financial Statement Presentation and Amounts

At March 31, 2013, the fair value of energy-related derivatives and interest rate derivatives was reflected in the balance sheets as follows:

Asset Derivatives at March 31, 2013

Derivative Category and Balance Sheet Location	Fair Value					
	Southern Company	Alabama Power	Georgia Power	Gulf Power	Mississippi Power	Southern Power
			(in millions)			
Derivatives designated as hedging instruments for regulatory purposes						
Energy-related derivatives:						
Other current assets	$ 25	$ 7	$ 6	$ 9	$ 3	
Other deferred charges and assets	20	5	7	5	3	
Total derivatives designated as hedging instruments for regulatory purposes	$ 45	$ 12	$ 13	$ 14	$ 6	N/A
Derivatives designated as hedging instruments in cash flow and fair value hedges						
Interest rate derivatives:						
Other current assets	$ 7	$ —	$ —	$ —	$ —	$ —
Other deferred charges and assets	3	—	—	—	—	—
Total derivatives designated as hedging instruments in cash flow and fair value hedges	$ 10	$ —	$ —	$ —	$ —	$ —
Derivatives not designated as hedging instruments						
Energy-related derivatives:						
Assets from risk management activities	$ 3	$ —	$ —	$ —	$ —	$ 3
Other deferred charges and assets	2	—	—	—	—	2
Total derivatives not designated as hedging instruments	$ 5	$ —	$ —	$ —	$ —	$ 5
Total asset derivatives	$ 60	$ 12	$ 13	$ 14	$ 6	$ 5

Liability Derivatives at March 31, 2013

Derivative Category and Balance Sheet Location	Fair Value					
	Southern Company	Alabama Power	Georgia Power	Gulf Power	Mississippi Power	Southern Power
			(in millions)			
Derivatives designated as hedging instruments for regulatory purposes						
Energy-related derivatives:						
Liabilities from risk management activities	$ 36	$ 5	$ 17	$ 8	$ 6	
Other deferred credits and liabilities	26	2	11	8	5	
Total derivatives designated as hedging instruments for regulatory purposes	$ 62	$ 7	$ 28	$ 16	$ 11	N/A
Derivatives not designated as hedging instruments						
Energy-related derivatives:						
Liabilities from risk management activities	$ 1	$ —	$ —	$ —	$ —	$ 1
Total liability derivatives	$ 63	$ 7	$ 28	$ 16	$ 11	$ 1

At December 31, 2012, the fair value of energy-related derivatives and interest rate derivatives was reflected in the balance sheets as follows:

Asset Derivatives at December 31, 2012

Derivative Category and Balance Sheet Location	Fair Value					
	Southern Company	Alabama Power	Georgia Power	Gulf Power	Mississippi Power	Southern Power
			(in millions)			
Derivatives designated as hedging instruments for regulatory purposes						
Energy-related derivatives:						
Other current assets	$ 10	$ 2	$ 6	$ 1	$ 1	
Other deferred charges and assets	13	3	5	3	2	
Total derivatives designated as hedging instruments for regulatory purposes	$ 23	$ 5	$ 11	$ 4	$ 3	N/A
Derivatives designated as hedging instruments in cash flow and fair value hedges						
Interest rate derivatives:						
Other current assets	$ 7	$ —	$ —	$ —	$ —	$ —
Other deferred charges and assets	3	—	—	—	—	—
Total derivatives designated as hedging instruments in cash flow and fair value hedges	$ 10	$ —	$ —	$ —	$ —	$ —
Derivatives not designated as hedging instruments						
Energy-related derivatives:						
Assets from risk management activities	$ 1	$ —	$ —	$ —	$ —	$ 1
Other deferred charges and assets	2	—	—	—	—	2
Total derivatives not designated as hedging instruments	$ 3	$ —	$ —	$ —	$ —	$ 3
Total asset derivatives	$ 36	$ 5	$ 11	$ 4	$ 3	$ 3

Liability Derivatives at December 31, 2012

Derivative Category and Balance Sheet Location	Fair Value					
	Southern Company	Alabama Power	Georgia Power	Gulf Power	Mississippi Power	Southern Power
			(in millions)			
Derivatives designated as hedging instruments for regulatory purposes						
Energy-related derivatives:						
Liabilities from risk management activities	$ 74	$ 14	$ 30	$ 17	$ 13	
Other deferred credits and liabilities	35	4	15	10	6	
Total derivatives designated as hedging instruments for regulatory purposes	$ 109	$ 18	$ 45	$ 27	$ 19	N/A
Derivatives not designated as hedging instruments						
Energy-related derivatives:						
Liabilities from risk management activities	$ 1	$ —	$ —	$ —	$ —	$ 1
Other deferred credits and liabilities	1	—	—	—	—	1
Total derivatives not designated as hedging instruments	$ 2	$ —	$ —	$ —	$ —	$ 2
Total liability derivatives	$ 111	$ 18	$ 45	$ 27	$ 19	$ 2

All derivative instruments are measured at fair value. See Note (C) herein for additional information.

Balance Sheet Offsetting

The derivative contracts of Southern Company, the traditional operating companies, and Southern Power are not subject to master netting arrangements or similar agreements and are reported gross on each registrant's financial statements. Some of these energy-related and interest rate derivative contracts contain certain provisions that permit intra-contract netting of derivative receivables and payables for routine billing and offsets related to events of default and settlements. Amounts related to energy-related derivative contracts are presented in the following tables. Interest rate derivatives presented in the tables above do not have amounts available for offset and are therefore excluded from the offsetting disclosure tables below.

Derivative Contracts at March 31, 2013

	Fair Value					
	Southern Company	Alabama Power	Georgia Power	Gulf Power	Mississippi Power	Southern Power
			(in millions)			
Assets						
Energy-related derivatives:						
Energy-related derivatives presented in the Balance Sheet [(a)]	$ 50	$ 12	$ 13	$ 14	$ 6	$ 5
Gross amounts not offset in the Balance Sheet [(b)]	(39)	(5)	(13)	(10)	(5)	(1)
Net energy-related derivative assets	$ 11	$ 7	$ —	$ 4	$ 1	$ 4
Liabilities						
Energy-related derivatives:						
Energy-related derivatives presented in the Balance Sheet [(a)]	$ 63	$ 7	$ 28	$ 16	$ 11	$ 1
Gross amounts not offset in the Balance Sheet [(b)]	(39)	(5)	(13)	(10)	(5)	(1)
Net energy-related derivative liabilities	$ 24	$ 2	$ 15	$ 6	$ 6	$ —

(a) None of the registrants offset fair value amounts for multiple derivative instruments executed with the same counterparty on the balance sheets; therefore, gross and net amounts of derivative assets and liabilities presented on the balance sheets are the same.

(b) Includes gross amounts subject to netting terms that are not offset on the balance sheets and any cash/financial collateral pledged or received.

Derivative Contracts at December 31, 2012

	Fair Value					
	Southern Company	Alabama Power	Georgia Power	Gulf Power	Mississippi Power	Southern Power
			(in millions)			
Assets						
Energy-related derivatives:						
Energy-related derivatives presented in the Balance Sheet [(a)]	$ 26	$ 5	$ 11	$ 4	$ 3	$ 3
Gross amounts not offset in the Balance Sheet [(b)]	(23)	(4)	(11)	(4)	(2)	(1)
Net energy-related derivative assets	$ 3	$ 1	$ —	$ —	$ 1	$ 2
Liabilities						
Energy-related derivatives:						
Energy-related derivatives presented in the Balance Sheet [(a)]	$ 111	$ 18	$ 45	$ 27	$ 19	$ 2
Gross amounts not offset in the Balance Sheet [(b)]	(23)	(4)	(11)	(4)	(2)	(1)
Net energy-related derivative liabilities	$ 88	$ 14	$ 34	$ 23	$ 17	$ 1

(a) None of the registrants offset fair value amounts for multiple derivative instruments executed with the same counterparty on the balance sheets; therefore, gross and net amounts of derivative assets and liabilities presented on the balance sheets are the same.

(b) Includes gross amounts subject to netting terms that are not offset on the balance sheets and any cash/financial collateral pledged or received.

At March 31, 2013 and December 31, 2012, the pre-tax effects of unrealized derivative gains (losses) arising from energy-related derivative instruments designated as regulatory hedging instruments and deferred on the balance sheets were as follows:

Regulatory Hedge Unrealized Gain (Loss) Recognized on the Balance Sheet at March 31, 2013

Derivative Category and Balance Sheet Location	Southern Company	Alabama Power	Georgia Power	Gulf Power	Mississippi Power
			(in millions)		
Energy-related derivatives:					
Other regulatory assets, current	$ (36)	$ (5)	$ (17)	$ (8)	$ (6)
Other regulatory assets, deferred	(26)	(2)	(11)	(8)	(5)
Other regulatory liabilities, current	25	7	6	9	3
Other regulatory liabilities, deferred	20	5	—	5	3
Other deferred credits and liabilities[a]	—	—	7	—	—
Total energy-related derivative gains (losses)	$ (17)	$ 5	$ (15)	$ (2)	$ (5)

(a) Georgia Power includes Other regulatory liabilities, deferred in Other deferred credits and liabilities.

Regulatory Hedge Unrealized Gain (Loss) Recognized on the Balance Sheet at December 31, 2012

Derivative Category and Balance Sheet Location	Southern Company	Alabama Power	Georgia Power	Gulf Power	Mississippi Power
			(in millions)		
Energy-related derivatives:					
Other regulatory assets, current	$ (74)	$ (14)	$ (30)	$ (17)	$ (13)
Other regulatory assets, deferred	(35)	(4)	(15)	(10)	(6)
Other regulatory liabilities, current	10	2	6	1	1
Other regulatory liabilities, deferred	13	3	—	3	2
Other deferred credits and liabilities[a]	—	—	5	—	—
Total energy-related derivative gains (losses)	$ (86)	$ (13)	$ (34)	$ (23)	$ (16)

(a) Georgia Power includes Other regulatory liabilities, deferred in Other deferred credits and liabilities.

For the three months ended March 31, 2013 and March 31, 2012, the pre-tax effects of interest rate derivatives designated as fair value hedging instruments on Southern Company's statements of income were immaterial.

For the three months ended March 31, 2013 and March 31, 2012, the pre-tax effects of foreign currency derivatives designated as fair value hedging instruments on Southern Company's and Mississippi Power's statements of income were immaterial and were offset with changes in the fair value of the purchase commitment related to equipment purchases; therefore, there was no impact on Southern Company's or Mississippi Power's statements of income.

For the three months ended March 31, 2013 and 2012, the pre-tax effects of interest rate derivatives designated as cash flow hedging instruments on the statements of income were as follows:

Derivatives in Cash Flow Hedging Relationships	Gain (Loss) Recognized in OCI on Derivative (Effective Portion)		Gain (Loss) Reclassified from AOCI into Income (Effective Portion)		
			Statements of Income Location	Amount	
	2013	2012		**2013**	2012
	(in millions)			*(in millions)*	
Southern Company					
Interest rate derivatives	**$ —**	$ 6	Interest expense, net of amounts capitalized	**$ (5)**	$ (3)
Alabama Power					
Interest rate derivatives	**$ —**	$ 7	Interest expense, net of amounts capitalized	**$ (1)**	$ —
Georgia Power					
Interest rate derivatives	**$ —**	$ —	Interest expense, net of amounts capitalized	**$ (1)**	$ (1)
Mississippi Power					
Interest rate derivatives	**$ —**	$ (1)	Interest expense, net of amounts capitalized	**$ —**	$ —
Southern Power					
Interest rate derivatives	**$ —**	$ —	Interest expense, net of amounts capitalized	**$ (3)**	$ (2)

For the three months ended March 31, 2013 and 2012, the pre-tax effects of energy-related derivatives designated as cash flow hedging instruments on the statements of income were immaterial for all registrants.

There was no material ineffectiveness recorded in earnings for any registrant for any period presented.

For Southern Power's energy-related derivatives not designated as hedging instruments, a substantial portion of the pre-tax realized and unrealized gains and losses is associated with hedging fuel price risk of certain PPA customers and has no impact on net income or on fuel expense as presented in Southern Company's and Southern Power's statements of income. As a result, for the three months ended March 31, 2013 and 2012, the pre-tax effects of energy-related derivatives not designated as hedging instruments on Southern Company's and Southern Power's statements of income were immaterial.

For the three months ended March 31, 2013 and March 31, 2012, the pre-tax effects of foreign currency derivatives not designated as hedging instruments were recorded as regulatory assets and liabilities and were immaterial for Southern Company and Mississippi Power.

Contingent Features

The registrants do not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. There are certain derivatives that could require collateral, but not accelerated payment, in the event of various credit rating changes of certain Southern Company subsidiaries.

At March 31, 2013, the fair value of derivative liabilities with contingent features, by registrant, was as follows:

	Southern Company	Alabama Power	Georgia Power	Gulf Power	Mississippi Power	Southern Power
			(in millions)			
Derivative liabilities	$ 1	$ —	$ 2	$ —	$ —	$ —

At March 31, 2013, the registrants had no collateral posted with their derivative counterparties. If collateral is required, fair value amounts recognized for the right to reclaim cash collateral or the obligation to return cash collateral are not offset against fair value amounts recognized for derivatives executed with the same counterparty. The maximum potential collateral requirements arising from the credit-risk-related contingent features, at a rating below BBB- and/or Baa3, were $1 million for each registrant. Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. For the traditional operating companies and Southern Power, included

in these amounts are certain agreements that could require collateral in the event that one or more Power Pool participants have a credit rating change to below investment grade.

Southern Company, the traditional operating companies, and Southern Power are exposed to losses related to financial instruments in the event of counterparties' nonperformance. Southern Company, the traditional operating companies, and Southern Power only enter into agreements and material transactions with counterparties that have investment grade credit ratings by Moody's and S&P or with counterparties who have posted collateral to cover potential credit exposure. Southern Company, the traditional operating companies, and Southern Power have also established risk management policies and controls to determine and monitor the creditworthiness of counterparties in order to mitigate Southern Company's, the traditional operating companies', and Southern Power's exposure to counterparty credit risk. Therefore, Southern Company, the traditional operating companies, and Southern Power do not anticipate a material adverse effect on the financial statements as a result of counterparty nonperformance.

(I) ACQUISITIONS

Campo Verde Solar, LLC Acquisition

On April 23, 2013, Southern Power and Turner Renewable Energy, LLC (TRE), through Southern Turner Renewable Energy, LLC (STR), a jointly-owned subsidiary owned 90% by Southern Power , acquired all of the outstanding membership interests of Campo Verde Solar, LLC (Campo Verde) from First Solar, Inc., the developer of the project. Campo Verde is constructing a 139-MW solar photovoltaic facility in Southern California. The solar facility is expected to begin commercial operation in the fourth quarter 2013. The output of the plant is contracted under a 20-year PPA with San Diego Gas & Electric Company, a subsidiary of Sempra Energy, that is expected to begin in the fourth quarter 2013. This PPA will be accounted for as an operating lease. The acquisition is in accordance with Southern Power's overall growth strategy.

Southern Power's acquisition of Campo Verde included cash consideration of $136.6 million. The allocation of the purchase price to individual assets has not been finalized. Under an engineering, procurement, and construction agreement (Construction Agreement), an additional $357.3 million will be paid to a subsidiary of First Solar, Inc. (Construction Contractor) to complete construction of the solar facility.

In the event certain unforeseeable conditions occur at the project site, the Construction Contractor may terminate the Construction Agreement, and in the event the Construction Contractor does not achieve certain construction or project development milestones by certain dates, STR may terminate the Construction Agreement. In each case, a subsidiary of First Solar will be required to make a termination payment to STR equal to STR's investment in Campo Verde (net of any tax or other benefits received by STR) and STR will be required to transfer its ownership in Campo Verde to the subsidiary of First Solar (the Termination Payment and Transfer). In addition, under the acquisition agreement, a subsidiary of First Solar may require the Termination Payment and Transfer to occur in the event costs relating to certain contingencies exceed a certain threshold until such time that the contingencies are satisfactorily resolved under the terms of the acquisition agreement, and STR may require the Termination Payment and Transfer to occur in the event certain contingencies are not satisfactorily resolved. The ultimate outcome of this matter cannot be determined at this time; however, STR believes the likelihood of a Termination Payment and Transfer to be remote at the acquisition date.

(J) INVESTMENTS IN LEVERAGED LEASES

See Note 1 to the financial statements of Southern Company under "Leveraged Leases" in Item 8 of the Form 10-K for additional information.

On March 1, 2013, Southern Company completed the restructuring of the nonrecourse debt and the related rental payments associated with its leveraged lease investment in a 440-MW generation facility located in Choctaw County, Mississippi. In connection with the restructuring, Southern Company has committed, as owner/lessor, to invest approximately $60 million in capital over the next three years to improve the operational performance of the facility and upgrade environmental controls. As part of the restructuring, the interest rate on the nonrecourse debt was significantly reduced, resulting in lower debt payments for Southern Company and lower rental payments for the lessee over the remaining 19-year term of the nonrecourse debt and the lease. As a consequence of the restructuring, Southern Company recalculated its net investment in the lease to reflect changes in the future cash flows to Southern Company as owner/lessor. As a result of the recalculation, Southern Company recorded an after-tax charge to income during the first quarter 2013 of approximately $16 million. This noncash charge reflects a reallocation of previously recognized lease income that will be reflected in income over the remaining term of the lease.

(K) SEGMENT AND RELATED INFORMATION

Southern Company's reportable business segments are the sale of electricity in the Southeast by the four traditional operating companies and Southern Power. Revenues from sales by Southern Power to the traditional operating companies were $78 million and $112 million for the three months ended March 31, 2013 and March 31, 2012, respectively. The "All Other" column includes parent Southern Company, which does not allocate operating expenses to business segments. Also, this category includes segments below the quantitative threshold for separate disclosure. These segments include investments in telecommunications and leveraged lease projects. All other intersegment revenues are not material. Financial data for business segments and products and services was as follows:

	Electric Utilities						
	Traditional Operating Companies	Southern Power	Eliminations	Total	All Other	Eliminations	Consolidated
				(in millions)			
Three Months Ended March 31, 2013:							
Operating revenues	$ 3,668	$ 303	$ (86)	$ 3,885	$ 35	$ (23)	$ 3,897
Segment net income (loss)[a][b]	66	29	—	95	(16)	2	81
Total assets at March 31, 2013	$ 58,752	$ 3,858	$ (109)	$ 62,501	$ 1,075	$ (302)	$ 63,274
Three Months Ended March 31, 2012:							
Operating revenues	$ 3,449	$ 254	$ (114)	$ 3,589	$ 38	$ (23)	$ 3,604
Segment net income (loss)[a]	339	29	1	369	2	(3)	368
Total assets at December 31, 2012	$ 58,600	$ 3,780	$ (129)	$ 62,251	$ 1,116	$ (218)	$ 63,149

(a) After dividends on preferred and preference stock of subsidiaries.

(b) Segment net income (loss) for the three months ended March 31, 2013 includes a $540.0 million pre-tax charge ($333.5 million after tax) for an estimated probable loss on the Kemper IGCC. See Note (B) under "Integrated Coal Gasification Combined Cycle" herein for additional information.

Products and Services

	Electric Utilities' Revenues			
	Retail	Wholesale	Other	Total
		(in millions)		
Three Months Ended March 31, 2013	$ 3,298	$ 432	$ 155	$ 3,885
Three Months Ended March 31, 2012	3,092	349	148	3,589

PART II — OTHER INFORMATION

Item 1. Legal Proceedings.

See the Notes to the Condensed Financial Statements herein for information regarding certain legal and administrative proceedings in which the registrants are involved.

Item 1A. Risk Factors.

See RISK FACTORS in Item 1A of the Form 10-K for a discussion of the risk factors of the registrants. There have been no material changes to these risk factors from those previously disclosed in the Form 10-K.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds.

(c) Issuer Purchases of Equity Securities

2013	Total Number of Shares Purchased [a]	Average Price Paid Per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs [a]
January 1 - January 31	—	N/A	N/A	N/A
February 1 - February 28	—	N/A	N/A	N/A
March 1 - March 31	—	N/A	N/A	
Total	**—**	**N/A**	**N/A**	**N/A**

(a) In July 2012, Southern Company announced a program to repurchase shares to partially offset the incremental shares issued under its employee and director stock plans. As of December 31, 2012, Southern Company had repurchased a total of 9,439,561 shares under this program. In January 2013, Southern Company announced that it plans to continue this program through 2015. There were no repurchases under this program in the first quarter 2013. Pursuant to approval by the Southern Company Board of Directors, Southern Company may repurchase shares through open market purchases or privately negotiated transactions, in accordance with applicable securities laws.

Item 5. Other Information

In December 2011, the Financial Accounting Standards Board (FASB) issued new guidance addressing balance sheet offsetting of financial instruments and derivative instruments. Under this guidance, companies are required to report gross and net information for recognized derivative instruments and financial instruments eligible for offset under existing GAAP or subject to enforceable master netting arrangements. The FASB also issued guidance in January 2013 to clarify the scope of the new requirement, narrowing its focus to derivative instruments, security lending and borrowing agreements, and repurchase and reverse repurchase arrangements. Although new disclosures are required to present the effect or potential effect of offset related to such instruments, the existing accounting guidance allowing (but not requiring) balance sheet offsetting remains unchanged.

Southern Company and each subsidiary registrant adopted the new guidance retrospectively on January 1, 2013. The table below reflects each registrant's retrospective application of this guidance at December 31, 2011. The retrospective application did not have a material impact on the financial condition or results of operations of Southern Company or any of its subsidiary registrants. See Note (H) to the Condensed Financial Statements under "Balance Sheet Offsetting" herein for additional information.

Asset Derivative Contracts at December 31, 2011 (Unaudited)

	Fair Value					
	Southern Company	**Alabama Power**	**Georgia Power**	**Gulf Power**	**Mississippi Power**	**Southern Power**
			(millions)			
Assets						
Energy-related derivatives						
Net amounts of assets presented in the Balance Sheet [a]	$ 14	$ —	$ 13	$ —	$ —	$ 1
Gross amounts not offset in the Balance Sheet [b]	(14)	—	(13)	—	—	(1)
Net energy-related derivatives	$ —	$ —	$ —	$ —	$ —	$ —
Interest rate derivatives						
Net amounts of assets presented in the Balance Sheet [a]	$ 13	$ —	$ —	$ —	$ —	$ —
Gross amounts not offset in the Balance Sheet [b]	—	—	—	—	—	—
Net interest rate derivatives	$ 13	$ —	$ —	$ —	$ —	$ —
Foreign currency derivatives						
Net amounts of assets presented in the Balance Sheet [a]	$ 2	$ —	$ —	$ —	$ 2	$ —
Gross amounts not offset in the Balance Sheet [b]	(2)	—	—	—	(2)	—
Net foreign currency derivatives	—	—	—	—	—	—
Total Net Derivative Assets	$ 13	$ —	$ —	$ —	$ —	$ —

[a] None of the registrants offset fair value amounts recognized for multiple derivative instruments executed with the same counterparty on the balance sheets; therefore, gross and net amounts of derivative assets and liabilities presented on the balance sheets are the same.

[b] Includes gross amounts subject to netting terms that are not offset on the balance sheet and any cash/financial collateral pledged or received.

Liability Derivative Contracts at December 31, 2011 (Unaudited)

	Fair Value					
	Southern Company	Alabama Power	Georgia Power	Gulf Power	Mississippi Power	Southern Power
	(millions)					
Liability						
Energy-related derivatives						
Net amounts of liabilities presented in the Balance Sheet [a]	$ 245	$ 48	$ 95	$ 41	$ 51	$ 10
Gross amounts not offset in the Balance Sheet [b]	(14)	—	(13)	—	—	—
Net energy-related derivatives	$ 231	$ 48	$ 82	$ 41	$ 51	$ 10
Interest rate derivatives						
Net amounts of liabilities presented in the Balance Sheet [a]	$ 33	$ 18	$ —	$ —	$ 15	$ —
Gross amounts not offset in the Balance Sheet [b]	—	—	—	—	—	—
Net interest rate derivatives	$ 33	$ 18	$ —	$ —	$ 15	$ —
Foreign currency derivatives						
Net amounts of liabilities presented in the Balance Sheet [a]	$ 3	$ —	$ —	$ —	$ 3	$ —
Gross amounts not offset in the Balance Sheet [b]	(2)	—	—	—	(2)	—
Net foreign currency derivatives	1	—	—	—	1	—
Total Net Derivative Liabilities	$ 265	$ 66	$ 82	$ 41	$ 67	$ 10

[a] None of the registrants offset fair value amounts recognized for multiple derivative instruments executed with the same counterparty on the balance sheets; therefore, gross and net amounts of derivative assets and liabilities presented on the balance sheets are the same.

[b] Includes gross amounts subject to netting terms that are not offset on the balance sheet and any cash/financial collateral pledged or received.

Item 6. Exhibits.

(4) Instruments Describing Rights of Security Holders, Including Indentures

Georgia Power

(c)1 - Fiftieth Supplemental Indenture to Senior Note Indenture dated as of March 15, 2013, providing for the issuance of the Series 2013A 4.30% Senior Notes due March 15, 2043. (Designated in Form 8-K dated March 12, 2013, File No. 1-6468, as Exhibit 4.2(a).)

(c)2 - Fifty-First Supplemental Indenture to Senior Note Indenture dated as of March 15, 2013, providing for the issuance of the Series 2013B Floating Rate Senior Notes due March 15, 2016. (Designated in Form 8-K dated March 12, 2013, File No. 1-6468, as Exhibit 4.2(b).)

(10) Material Contracts

Southern Company

(a)1 - Base Salaries of Named Executive Officers.

(a)2 - Letter Agreement between Southern Company and Stephen E. Kuczynski dated June 4, 2011 regarding the terms of an offer of employment.

(a)3 - Retention and Restricted Stock Unit Award Agreement between Southern Nuclear and Stephen E. Kuczynski effective as of July 11, 2011.

Georgia Power

(c)1 - Base Salaries of Named Executive Officers.

(24) Power of Attorney and Resolutions

Southern Company

(a)1 - Power of Attorney and resolution. (Designated in the Form 10-K for the year ended December 31, 2012, File No. 1-3526 as Exhibit 24(a) and incorporated herein by reference.)

Alabama Power

(b)1 - Power of Attorney and resolution. (Designated in the Form 10-K for the year ended December 31, 2012, File No. 1-3164 as Exhibit 24(b) and incorporated herein by reference.)

Georgia Power

(c)1 - Power of Attorney and resolution. (Designated in the Form 10-K for the year ended December 31, 2012, File No. 1-6468 as Exhibit 24(c) and incorporated herein by reference.)

(c)2 - Power of Attorney for W. Ron Hinson.

Gulf Power

(d)1 - Power of Attorney and resolution. (Designated in the Form 10-K for the year ended December 31, 2012, File No. 001-31737 as Exhibit 24(d) and incorporated herein by reference.)

Mississippi Power

(e)1 - Power of Attorney and resolution. (Designated in the Form 10-K for the year ended December 31, 2012, File No. 001-11229 as Exhibit 24(e) and incorporated herein by reference.)

Southern Power

(f)1 - Power of Attorney and resolution. (Designated in the Form 10-K for the year ended December 31, 2012, File No. 333-98553 as Exhibit 24(f) and incorporated herein by reference.)

(31) Section 302 Certifications

Southern Company

(a)1 - Certificate of Southern Company's Chief Executive Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.

(a)2 - Certificate of Southern Company's Chief Financial Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.

Alabama Power

(b)1 - Certificate of Alabama Power's Chief Executive Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.

(b)2 - Certificate of Alabama Power's Chief Financial Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.

Georgia Power

(c)1 - Certificate of Georgia Power's Chief Executive Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.

(c)2 - Certificate of Georgia Power's Chief Financial Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.

Gulf Power

(d)1 - Certificate of Gulf Power's Chief Executive Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.

(d)2 - Certificate of Gulf Power's Chief Financial Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.

Mississippi Power

(e)1 - Certificate of Mississippi Power's Chief Executive Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.

(e)2 - Certificate of Mississippi Power's Chief Financial Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.

Southern Power

(f)1 - Certificate of Southern Power's Chief Executive Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.

(f)2 - Certificate of Southern Power's Chief Financial Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.

(32) Section 906 Certifications

Southern Company

(a) - Certificate of Southern Company's Chief Executive Officer and Chief Financial Officer required by Section 906 of the Sarbanes-Oxley Act of 2002.

Alabama Power

(b) - Certificate of Alabama Power's Chief Executive Officer and Chief Financial Officer required by Section 906 of the Sarbanes-Oxley Act of 2002.

Georgia Power

(c) - Certificate of Georgia Power's Chief Executive Officer and Chief Financial Officer required by Section 906 of the Sarbanes-Oxley Act of 2002.

Gulf Power

(d) - Certificate of Gulf Power's Chief Executive Officer and Chief Financial Officer required by Section 906 of the Sarbanes-Oxley Act of 2002.

Mississippi Power

(e) - Certificate of Mississippi Power's Chief Executive Officer and Chief Financial Officer required by Section 906 of the Sarbanes-Oxley Act of 2002.

Southern Power

(f) - Certificate of Southern Power's Chief Executive Officer and Chief Financial Officer required by Section 906 of the Sarbanes-Oxley Act of 2002.

(101)	**XBRL — Related Documents**
INS	XBRL Instance Document
SCH	XBRL Taxonomy Extension Schema Document
CAL	XBRL Taxonomy Calculation Linkbase Document
DEF	XBRL Definition Linkbase Document
LAB	XBRL Taxonomy Label Linkbase Document
PRE	XBRL Taxonomy Presentation Linkbase Document

THE SOUTHERN COMPANY

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof included in such company's report.

THE SOUTHERN COMPANY

By *Thomas A. Fanning*
Chairman, President, and Chief Executive Officer
(Principal Executive Officer)

By *Art P. Beattie*
Executive Vice President and Chief Financial Officer
(Principal Financial Officer)

By */s/ Melissa K. Caen*
(Melissa K. Caen, Attorney-in-fact)

Date: May 10, 2013

ALABAMA POWER COMPANY

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof included in such company's report.

ALABAMA POWER COMPANY

By *Charles D. McCrary*
President and Chief Executive Officer
(Principal Executive Officer)

By *Philip C. Raymond*
Executive Vice President, Chief Financial Officer, and Treasurer
(Principal Financial Officer)

By */s/ Melissa K. Caen*
(Melissa K. Caen, Attorney-in-fact)

Date: May 10, 2013

GEORGIA POWER COMPANY

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof included in such company's report.

GEORGIA POWER COMPANY

By *W. Paul Bowers*
President and Chief Executive Officer
(Principal Executive Officer)

By *W. Ron Hinson*
Executive Vice President, Chief Financial Officer, Treasurer, and Comptroller
(Principal Financial Officer)

By */s/ Melissa K. Caen*
(Melissa K. Caen, Attorney-in-fact)

Date: May 10, 2013

GULF POWER COMPANY

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof included in such company's report.

GULF POWER COMPANY

By *S. W. Connally, Jr.*
President and Chief Executive Officer
(Principal Executive Officer)

By *Richard S. Teel*
Vice President and Chief Financial Officer
(Principal Financial Officer)

By */s/ Melissa K. Caen*
(Melissa K. Caen, Attorney-in-fact)

Date: May 10, 2013

MISSISSIPPI POWER COMPANY

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof included in such company's report.

MISSISSIPPI POWER COMPANY

By *Edward Day, VI*
President and Chief Executive Officer
(Principal Executive Officer)

By *Moses H. Feagin*
Vice President, Chief Financial Officer, and Treasurer
(Principal Financial Officer)

By */s/ Melissa K. Caen*
(Melissa K. Caen, Attorney-in-fact)

Date: May 10, 2013

SOUTHERN POWER COMPANY

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof included in such company's report.

SOUTHERN POWER COMPANY

By *Oscar C. Harper IV*
President and Chief Executive Officer
(Principal Executive Officer)

By *Michael W. Southern*
Senior Vice President, Chief Financial Officer, and Treasurer
(Principal Financial Officer)

By */s/ Melissa K. Caen*
(Melissa K. Caen, Attorney-in-fact)

Date: May 10, 2013

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

☑ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the Fiscal Year Ended December 31, 2012

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the Transition Period from to

Commission File Number	Registrant, State of Incorporation, Address and Telephone Number	I.R.S. Employer Identification No.
1-3526	**The Southern Company** (A Delaware Corporation) 30 Ivan Allen Jr. Boulevard, N.W. Atlanta, Georgia 30308 (404) 506-5000	58-0690070
1-3164	**Alabama Power Company** (An Alabama Corporation) 600 North 18th Street Birmingham, Alabama 35291 (205) 257-1000	63-0004250
1-6468	**Georgia Power Company** (A Georgia Corporation) 241 Ralph McGill Boulevard, N.E. Atlanta, Georgia 30308 (404) 506-6526	58-0257110
001-31737	**Gulf Power Company** (A Florida Corporation) One Energy Place Pensacola, Florida 32520 (850) 444-6111	59-0276810
001-11229	**Mississippi Power Company** (A Mississippi Corporation) 2992 West Beach Boulevard Gulfport, Mississippi 39501 (228) 864-1211	64-0205820
333-98553	**Southern Power Company** (A Delaware Corporation) 30 Ivan Allen Jr. Boulevard, N.W. Atlanta, Georgia 30308 (404) 506-5000	58-2598670

Securities registered pursuant to Section 12(b) of the Act:[1]

Each of the following classes or series of securities registered pursuant to Section 12(b) of the Act is listed on the New York Stock Exchange.

Title of each class			Registrant
Common Stock, $5 par value			**The Southern Company**
Class A preferred, cumulative, $25 stated capital			**Alabama Power Company**
5.20% Series		5.83% Series	
5.30% Series			
Class A Preferred Stock, non-cumulative, Par value $25 per share			**Georgia Power Company**
6 1/8% Series			
Senior Notes			
8.20% Series 2008C			
Senior Notes			**Gulf Power Company**
5.25% Series H			
5.75% Series 2011A			
			Mississippi Power Company
Depositary preferred shares, each representing one-fourth of a share of preferred stock, cumulative, $100 par value			
5.25% Series			

Securities registered pursuant to Section 12(g) of the Act:[1]

Title of each class			Registrant
Preferred stock, cumulative, $100 par value			**Alabama Power Company**
4.20% Series	4.60% Series	4.72% Series	
4.52% Series	4.64% Series	4.92% Series	
Preferred stock, cumulative, $100 par value			**Mississippi Power Company**
4.40% Series	4.60% Series		
4.72% Series			

1 As of December 31, 2012.

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.

Registrant	Yes	No
The Southern Company	X	
Alabama Power Company	X	
Georgia Power Company	X	
Gulf Power Company		X
Mississippi Power Company		X
Southern Power Company		X

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☒ (Response applicable to all registrants.)

Indicate by check mark whether the registrants (1) have filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrants were required to file such reports), and (2) have been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrants have submitted electronically and posted on their corporate web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrants were required to submit and post such files). Yes ☒ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrants' knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☒

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Registrant	Large Accelerated Filer	Accelerated Filer	Non-accelerated Filer	Smaller Reporting Company
The Southern Company	X			
Alabama Power Company			X	
Georgia Power Company			X	
Gulf Power Company			X	
Mississippi Power Company			X	
Southern Power Company			X	

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☒ (Response applicable to all registrants.)

Aggregate market value of The Southern Company's common stock held by non-affiliates of The Southern Company at June 30, 2012: $40.5 billion. All of the common stock of the other registrants is held by The Southern Company. A description of each registrant's common stock follows:

Registrant	Description of Common Stock	Shares Outstanding at January 31, 2013
The Southern Company	Par Value $5 Per Share	868,969,827
Alabama Power Company	Par Value $40 Per Share	30,537,500
Georgia Power Company	Without Par Value	9,261,500
Gulf Power Company	Without Par Value	4,542,717
Mississippi Power Company	Without Par Value	1,121,000
Southern Power Company	Par Value $0.01 Per Share	1,000

Documents incorporated by reference: specified portions of The Southern Company's Definitive Proxy Statement on Schedule 14A relating to the 2013 Annual Meeting of Stockholders are incorporated by reference into PART III. In addition, specified portions of the Definitive Information Statements on Schedule 14C of Alabama Power Company, Georgia Power Company, and Mississippi Power Company relating to each of their respective 2013 Annual Meetings of Shareholders are incorporated by reference into PART III.

Southern Power Company meets the conditions set forth in General Instructions I(1)(a) and (b) of Form 10-K and is therefore filing this Form 10-K with the reduced disclosure format specified in General Instructions I(2)(b), (c), and (d) of Form 10-K.

This combined Form 10-K is separately filed by The Southern Company, Alabama Power Company, Georgia Power Company, Gulf Power Company, Mississippi Power Company, and Southern Power Company. Information contained herein relating to any individual company is filed by such company on its own behalf. Each company makes no representation as to information relating to the other companies.

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DEFINITIONS

When used in Items 1 through 5 and Items 9A through 15, the following terms will have the meanings indicated.

Term	Meaning
2010 ARP	Alternative Rate Plan approved by the Georgia PSC for Georgia Power for the years 2011 through 2013
Alabama Power	Alabama Power Company
Clean Air Act	Clean Air Act Amendments of 1990
Code	Internal Revenue Code of 1986, as amended
CPCN	Certificate of Public Convenience and Necessity
CWIP	Construction Work in Progress
Dalton	Dalton Utilities
DOE	United States Department of Energy
EPA	United States Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
FMPA	Florida Municipal Power Agency
Georgia Power	Georgia Power Company
Gulf Power	Gulf Power Company
IBEW	International Brotherhood of Electrical Workers
IGCC	Integrated Coal Gasification Combined Cycle
IIC	Intercompany Interchange Contract
IPP	Independent Power Producer
IRP	Integrated Resource Plan
Kemper IGCC	IGCC facility under construction in Kemper County, Mississippi
KUA	Kissimmee Utility Authority
KW	Kilowatt
KWH	Kilowatt-hour
MATS rule	Mercury and Air Toxics Standards rule
MEAG Power	Municipal Electric Authority of Georgia
Mississippi Power	Mississippi Power Company
MW	Megawatt
NRC	Nuclear Regulatory Commission
OPC	Oglethorpe Power Corporation
OUC	Orlando Utilities Commission
Plant Vogtle Units 3 and 4	Two new nuclear generating units under construction at Plant Vogtle
power pool	The operating arrangement whereby the integrated generating resources of the traditional operating companies and Southern Power are subject to joint commitment and dispatch in order to serve their combined load obligations
PowerSouth	PowerSouth Energy Cooperative
PPA	Power Purchase Agreement

DEFINITIONS
(continued)

Term	Meaning
Progress Energy Florida	Florida Power Corporation, d/b/a Progress Energy Florida, Inc.
PSC	Public Service Commission
registrants	Southern Company, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, and Southern Power
RUS	Rural Utilities Service (formerly Rural Electrification Administration)
SCS	Southern Company Services, Inc. (the system service company)
SEC	Securities and Exchange Commission
SEGCO	Southern Electric Generating Company
SEPA	Southeastern Power Administration
SERC	Southeastern Electric Reliability Council
SMEPA	South Mississippi Electric Power Association
Southern Company	The Southern Company
Southern Company system	Southern Company, the traditional operating companies, Southern Power, SEGCO, Southern Nuclear, SCS, SouthernLINC Wireless, and other subsidiaries
Southern Holdings	Southern Company Holdings, Inc.
SouthernLINC Wireless	Southern Communications Services, Inc.
Southern Nuclear	Southern Nuclear Operating Company, Inc.
Southern Power	Southern Power Company
traditional operating companies	Alabama Power, Georgia Power, Gulf Power, and Mississippi Power

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

This Annual Report on Form 10-K contains forward-looking statements. Forward-looking statements include, among other things, statements concerning retail sales, retail rates, the strategic goals for the wholesale business, customer growth, economic recovery, fuel and environmental cost recovery and other rate actions, current and proposed environmental regulations and related estimated expenditures, access to sources of capital, dividend payout ratios, projections for the qualified pension plan, postretirement benefit plan, and nuclear decommissioning trust fund contributions, financing activities, start and completion dates of construction projects, plans and estimated costs for new generation resources, filings with state and federal regulatory authorities, impact of the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010, impact of the American Taxpayer Relief Act of 2012, estimated sales and purchases under new power sale and purchase agreements, and estimated construction and other expenditures. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "could," "should," "expects," "plans," "anticipates," "believes," "estimates," "projects," "predicts," "potential," or "continue" or the negative of these terms or other similar terminology. There are various factors that could cause actual results to differ materially from those suggested by the forward-looking statements; accordingly, there can be no assurance that such indicated results will be realized. These factors include:

- the impact of recent and future federal and state regulatory changes, including legislative and regulatory initiatives regarding deregulation and restructuring of the electric utility industry, environmental laws including regulation of water, coal combustion byproducts, and emissions of sulfur, nitrogen, carbon, soot, particulate matter, hazardous air pollutants, including mercury, and other substances, financial reform legislation, and also changes in tax and other laws and regulations to which Southern Company and its subsidiaries are subject, as well as changes in application of existing laws and regulations;
- current and future litigation, regulatory investigations, proceedings, or inquiries, including the pending EPA civil actions against certain Southern Company subsidiaries, FERC matters, and Internal Revenue Service and state tax audits;
- the effects, extent, and timing of the entry of additional competition in the markets in which Southern Company's subsidiaries operate;
- variations in demand for electricity, including those relating to weather, the general economy and recovery from the recent recession, population and business growth (and declines), the effects of energy conservation measures, and any potential economic impacts resulting from federal fiscal decisions;
- available sources and costs of fuels;
- effects of inflation;
- ability to control costs and avoid cost overruns during the development and construction of facilities, including the development and construction of facilities with designs that have not been finalized or previously constructed, to construct facilities in accordance with the requirements of permits and licenses, and to satisfy any operational and environmental performance standards, including the requirements of tax credits and other incentives;
- investment performance of Southern Company's employee benefit plans and nuclear decommissioning trust funds;
- advances in technology;
- state and federal rate regulations and the impact of pending and future rate cases and negotiations, including rate actions relating to fuel and other cost recovery mechanisms;
- regulatory approvals and actions related to Plant Vogtle Units 3 and 4, including Georgia PSC approvals, NRC actions, and potential DOE loan guarantees;
- regulatory approvals and legislative actions related to the Kemper IGCC, including Mississippi PSC approvals and legislation relating to cost recovery for the Kemper IGCC, the SMEPA purchase decision, satisfaction of requirements to utilize investment tax credits and grants, and the outcome of any proceedings regarding the Mississippi PSC's issuance of the CPCN for the Kemper IGCC;
- the inherent risks involved in operating and constructing nuclear generating facilities, including environmental, health, regulatory, natural disaster, terrorism, and financial risks;
- the performance of projects undertaken by the non-utility businesses and the success of efforts to invest in and develop new opportunities;
- internal restructuring or other restructuring options that may be pursued;

- potential business strategies, including acquisitions or dispositions of assets or businesses, which cannot be assured to be completed or beneficial to Southern Company or its subsidiaries;
- the ability of counterparties of Southern Company and its subsidiaries to make payments as and when due and to perform as required;
- the ability to obtain new short- and long-term contracts with wholesale customers;
- the direct or indirect effect on the Southern Company system's business resulting from terrorist incidents and the threat of terrorist incidents, including cyber intrusion;
- interest rate fluctuations and financial market conditions and the results of financing efforts, including Southern Company's and its subsidiaries' credit ratings;
- the impacts of any potential U.S. credit rating downgrade or other sovereign financial issues, including impacts on interest rates, access to capital markets, impacts on currency exchange rates, counterparty performance, and the economy in general, as well as potential impacts on the availability or benefits of proposed DOE loan guarantees;
- the ability of Southern Company and its subsidiaries to obtain additional generating capacity at competitive prices;
- catastrophic events such as fires, earthquakes, explosions, floods, hurricanes, droughts, pandemic health events such as influenzas, or other similar occurrences;
- the direct or indirect effects on the Southern Company system's business resulting from incidents affecting the U.S. electric grid or operation of generating resources;
- the effect of accounting pronouncements issued periodically by standard setting bodies; and
- other factors discussed elsewhere herein and in other reports filed by the registrants from time to time with the SEC.

The registrants expressly disclaim any obligation to update any forward-looking statements.

PART I

Item 1. BUSINESS

Southern Company was incorporated under the laws of Delaware on November 9, 1945. Southern Company is registered and qualified to do business under the laws of Georgia and is qualified to do business as a foreign corporation under the laws of Alabama. Southern Company owns all of the outstanding common stock of Alabama Power, Georgia Power, Gulf Power, and Mississippi Power, each of which is an operating public utility company. The traditional operating companies supply electric service in the states of Alabama, Georgia, Florida, and Mississippi. More particular information relating to each of the traditional operating companies is as follows:

Alabama Power is a corporation organized under the laws of the State of Alabama on November 10, 1927, by the consolidation of a predecessor Alabama Power Company, Gulf Electric Company, and Houston Power Company. The predecessor Alabama Power Company had been in continuous existence since its incorporation in 1906.

Georgia Power was incorporated under the laws of the State of Georgia on June 26, 1930 and was admitted to do business in Alabama on September 15, 1948 and in Florida on October 13, 1997.

Gulf Power is a Florida corporation that has had a continuous existence since it was originally organized under the laws of the State of Maine on November 2, 1925. Gulf Power was admitted to do business in Florida on January 15, 1926, in Mississippi on October 25, 1976, and in Georgia on November 20, 1984. Gulf Power became a Florida corporation after being domesticated under the laws of the State of Florida on November 2, 2005.

Mississippi Power was incorporated under the laws of the State of Mississippi on July 12, 1972, was admitted to do business in Alabama on November 28, 1972, and effective December 21, 1972, by the merger into it of the predecessor Mississippi Power Company, succeeded to the business and properties of the latter company. The predecessor Mississippi Power Company was incorporated under the laws of the State of Maine on November 24, 1924 and was admitted to do business in Mississippi on December 23, 1924 and in Alabama on December 7, 1962.

In addition, Southern Company owns all of the common stock of Southern Power, which is also an operating public utility company. Southern Power and it subsidiaries construct, acquire, own, and manage generation assets, including renewable energy projects, and sell electricity at market-based rates in the wholesale market. Southern Power is a corporation organized under the laws of Delaware on January 8, 2001 and was admitted to do business in the States of Alabama, Florida, and Georgia on January 10, 2001, in the State of Mississippi on January 30, 2001, in the State of North Carolina on February 19, 2007, and in the State of South Carolina on March 31, 2009. Certain of Southern Power's subsidiaries are also admitted to do business in the States of Nevada, New Mexico, and Texas.

Southern Company also owns all of the outstanding common stock or membership interests of SouthernLINC Wireless, Southern Nuclear, SCS, Southern Holdings, and other direct and indirect subsidiaries. SouthernLINC Wireless provides digital wireless communications for use by Southern Company and its subsidiary companies and markets these services to the public and also provides wholesale fiber optic solutions to telecommunication providers in the Southeast. Southern Nuclear operates and provides services to Alabama Power's and Georgia Power's nuclear plants and is currently developing Plant Vogtle Units 3 and 4, which are co-owned by Georgia Power. SCS is the system service company providing, at cost, specialized services to Southern Company and its subsidiary companies. Southern Holdings is an intermediate holding subsidiary, primarily for Southern Company's investments in leveraged leases.

Alabama Power and Georgia Power each own 50% of the outstanding common stock of SEGCO. SEGCO is an operating public utility company that owns electric generating units with an aggregate capacity of 1,019,680 KWs at Plant Gaston on the Coosa River near Wilsonville, Alabama. Alabama Power and Georgia Power are each entitled to one-half of SEGCO's capacity and energy. Alabama Power acts as SEGCO's agent in the operation of SEGCO's units and furnishes fuel to SEGCO for its units.

SEGCO also owns one 230,000 volt transmission line extending from Plant Gaston to the Georgia state line at which point connection is made with the Georgia Power transmission line system.

Southern Company's segment information is included in Note 12 to the financial statements of Southern Company in Item 8 herein.

The registrants' Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, and all amendments to those reports are made available on Southern Company's website, free of charge, as soon as reasonably practicable after such material is electronically filed with or furnished to the SEC. Southern Company's internet address is www.southerncompany.com.

The Southern Company System

Traditional Operating Companies

The traditional operating companies own generation, transmission, and distribution facilities. See PROPERTIES in Item 2 herein for additional information on the traditional operating companies' generating facilities. Each company's transmission facilities are connected to the respective company's own generating plants and other sources of power (including certain generating plants owned by Southern Power) and are interconnected with the transmission facilities of the other traditional operating companies and SEGCO. For information on the State of Georgia's integrated transmission system, see "Territory Served by the Traditional Operating Companies and Southern Power" herein.

Agreements in effect with principal neighboring utility systems provide for capacity and energy transactions that may be entered into from time to time for reasons related to reliability or economics. Additionally, the traditional operating companies have entered into voluntary reliability agreements with the subsidiaries of Entergy Corporation, Florida Electric Power Coordinating Group, and Tennessee Valley Authority and with Carolina Power & Light Company (d/b/a Progress Energy Carolinas, Inc.), Duke Energy Corporation, South Carolina Electric & Gas Company, and Virginia Electric and Power Company, each of which provides for the establishment and periodic review of principles and procedures for planning and operation of generation and transmission facilities, maintenance schedules, load retention programs, emergency operations, and other matters affecting the reliability of bulk power supply. The traditional operating companies have joined with other utilities in the Southeast (including some of those referred to above) to form the SERC to augment further the reliability and adequacy of bulk power supply. Through the SERC, the traditional operating companies are represented on the National Electric Reliability Council.

The utility assets of the traditional operating companies and certain utility assets of Southern Power are operated as a single integrated electric system, or power pool, pursuant to the IIC. Activities under the IIC are administered by SCS, which acts as agent for the traditional operating companies and Southern Power. The fundamental purpose of the power pool is to provide for the coordinated operation of the electric facilities in an effort to achieve the maximum possible economies consistent with the highest practicable reliability of service. Subject to service requirements and other operating limitations, system resources are committed and controlled through the application of centralized economic dispatch. Under the IIC, each traditional operating company and Southern Power retains its lowest cost energy resources for the benefit of its own customers and delivers any excess energy to the power pool for use in serving customers of other traditional operating companies or Southern Power or for sale by the power pool to third parties. The IIC provides for the recovery of specified costs associated with the affiliated operations thereunder, as well as the proportionate sharing of costs and revenues resulting from power pool transactions with third parties.

Southern Company, each traditional operating company, Southern Power, Southern Nuclear, SEGCO, and other subsidiaries have contracted with SCS to furnish, at direct or allocated cost and upon request, the following services: general and design engineering, operations, purchasing, accounting, finance and treasury, tax, information technology, marketing, auditing, insurance and pension administration, human resources, systems and procedures, digital wireless communications, and other services with respect to business and operations and power pool transactions. Southern Power and SouthernLINC Wireless have also secured from the traditional operating companies certain services which are furnished at cost and, in the case of Southern Power, which are subject to FERC regulations.

Alabama Power and Georgia Power each have a contract with Southern Nuclear to operate the Southern Company system's existing nuclear plants, Plants Farley, Hatch, and Vogtle. In addition, Georgia Power has a contract with Southern Nuclear to develop, license, construct, and operate Plant Vogtle Units 3 and 4. See "Regulation – Nuclear Regulation" herein for additional information.

Southern Power

Southern Power is an electric wholesale generation subsidiary with market-based rate authority from the FERC. Southern Power and its subsidiaries construct, acquire, own, and manage generation assets, including renewable energy projects, and sell electricity at market-based rates in the wholesale market. Southern Power's business activities are not subject to traditional state regulation like the traditional operating companies but are subject to regulation by the FERC. Southern Power has attempted to insulate itself from significant fuel supply, fuel transportation, and electric transmission risks by generally making such risks the responsibility of the counterparties to its PPAs. However, Southern Power's future earnings will depend on the parameters of the wholesale market and the efficient operation of its wholesale generating assets. For additional information on Southern Power's business activities, see MANAGEMENT'S DISCUSSION AND ANALYSIS – OVERVIEW – "Business Activities" of Southern Power in Item 7 herein.

In June 2012, Southern Power completed construction of Plant Nacogdoches, a biomass generating plant near Sacul, Texas with a nameplate capacity of approximately 116 MWs. Nacogdoches Power, LLC, a wholly-owned subsidiary of Southern Power, has a PPA covering the entire output of the plant from 2012 through 2032.

In December 2012, Southern Power completed construction of Plant Cleveland Units 1 through 4, a combustion turbine natural gas generating plant, in Cleveland County, North Carolina. The plant has a nameplate capacity of 720 MWs. Southern Power has long-term PPAs for 540 MWs of the generating capacity of the plant (180 MWs through 2031 and 360 MWs through 2036).

In 2012, Southern Power and Turner Renewable Energy, Inc. (TRE), through Southern Turner Renewable Energy LLC (STR), a jointly-owned subsidiary owned 90% by Southern Power, acquired all of the outstanding membership interests of Apex Nevada Solar, LLC (Apex), Spectrum Nevada Solar, LLC (Spectrum), and Granville Solar, LLC (Granville). Apex owns a 20-MW solar photovoltaic facility in North Las Vegas, Nevada. The solar facility began commercial operation on July 21, 2012. Apex has a PPA covering the entire output of the plant from 2012 through 2037. Granville owns a 2.5-MW solar photovoltaic facility in Oxford, North Carolina. The solar facility began commercial operation on October 28, 2012. Granville has a PPA covering the entire output of the plant from 2012 through 2032. Spectrum is constructing a 30-MW solar photovoltaic facility in North Las Vegas, Nevada. The solar facility is expected to begin commercial operation in mid-2013. Spectrum has a PPA covering the entire output of the plant from 2013 through 2038. These acquisitions added a total of 47 MWs of solar capacity to Southern Power's generation portfolio and are in accordance with Southern Power's overall growth strategy.

As of December 31, 2012, Southern Power had 8,764 MWs of nameplate capacity in commercial operation.

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Power Sales Agreements" and "Acquisitions" of Southern Power in Item 7 herein and Note 2 to the financial statements of Southern Power in Item 8 herein for additional information.

Other Businesses

Southern Holdings is an intermediate holding subsidiary, primarily for Southern Company's investments in leveraged leases.

SouthernLINC Wireless provides digital wireless communications for use by Southern Company and its subsidiary companies and markets its services to non-affiliates within the Southeast. SouthernLINC Wireless delivers multiple wireless communication options including push to talk, cellular service, text messaging, wireless internet access, and wireless data. Its system covers approximately 127,000 square miles in the Southeast. SouthernLINC Wireless also provides wholesale fiber optic solutions to telecommunication providers in the Southeast under the name Southern Telecom.

These efforts to invest in and develop new business opportunities offer potential returns exceeding those of rate-regulated operations. However, these activities also involve a higher degree of risk.

Construction Programs

The subsidiary companies of Southern Company are engaged in continuous construction programs to accommodate existing and estimated future loads on their respective systems. For estimated construction and environmental expenditures for the periods 2013 through 2015, see MANAGEMENT'S DISCUSSION AND ANALYSIS – FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" of Southern Company, each traditional operating company, and Southern Power in Item 7 herein. The Southern Company system's construction program consists of capital investment and capital expenditures to comply with existing environmental statutes and regulations. In 2013, the construction program is expected to be apportioned approximately as follows:

	Southern Company system *	Alabama Power	Georgia Power	Gulf Power	Mississippi Power
			(in millions)		
New Generation	$ 1,052	$ —	$ 555	$ —	$ 497
Environmental **	957	195	476	158	129
Transmission & Distribution Growth	655	176	284	16	30
Maintenance (Generation, Transmission, and Distribution)	1,339	597	611	145	135
Nuclear Fuel	269	97	172	—	—
General Plant	190	84	84	16	5
	4,462	1,149	2,182	335	796
Southern Power	910	—	—	—	—
Other subsidiaries	108	—	—	—	—
Total	$ 5,480	$ 1,149	$ 2,182	$ 335	$ 796

* These amounts include the amounts for the traditional operating companies and Southern Power (as detailed in the table above) as well as the amounts for the other subsidiaries. See "Other Businesses" herein for additional information.

** Reflects cost estimates for existing environmental regulations, including the MATS rule. The Southern Company system continues to monitor the development of the EPA's proposed water and coal combustion byproducts rules and to evaluate compliance options. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations" and FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" of Southern Company and each traditional operating company in Item 7 herein for additional information. See also MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations" of Southern Power in Item 7 herein for additional information.

The construction programs are subject to periodic review and revision, and actual construction costs may vary from these estimates because of numerous factors. These factors include: changes in business conditions; changes in load projections; changes in the expected environmental compliance program; changes in environmental statutes and regulations; the outcome of any legal challenges to the environmental rules; changes in generating plants, including unit retirements and replacements and adding or changing fuel sources at existing units, to meet regulatory requirements; changes in FERC rules and regulations; PSC approvals; changes in legislation; the cost and efficiency of construction labor, equipment, and materials; project scope and design changes; storm impacts; and the cost of capital. In addition, there can be no assurance that costs related to capital expenditures will be fully recovered.

See "Regulation – Environmental Statutes and Regulations" herein for additional information with respect to certain existing and proposed environmental requirements and PROPERTIES – "Jointly-Owned Facilities" in Item 2 herein for additional information concerning Alabama Power's, Georgia Power's, and Southern Power's joint ownership of certain generating units and related facilities with certain non-affiliated utilities. See Note 3 to the financial statements of Southern Company and Georgia Power under "Retail Regulatory Matters – Georgia Power – Nuclear Construction" and "Retail Regulatory Matters – Nuclear Construction," respectively. Also see Note 3 to the financial statements of each of Southern Company and Mississippi Power under "Integrated Coal Gasification Combined Cycle" for additional information.

Financing Programs

See each of the registrant's MANAGEMENT'S DISCUSSION AND ANALYSIS – FINANCIAL CONDITION AND LIQUIDITY in Item 7 herein and Note 6 to the financial statements of each registrant in Item 8 herein for information concerning financing programs.

Fuel Supply

The traditional operating companies' and SEGCO's supply of electricity is primarily fueled by natural gas and coal. Southern Power's supply of electricity is primarily fueled by natural gas. See MANAGEMENT'S DISCUSSION AND ANALYSIS – RESULTS OF OPERATION – "Electricity Business – Fuel and Purchased Power Expenses" of Southern Company and MANAGEMENT'S DISCUSSION AND ANALYSIS – RESULTS OF OPERATION – "Fuel and Purchased Power Expenses" of each traditional operating company in Item 7 herein for information regarding the electricity generated and the average cost of fuel in cents per net KWH generated for the years 2010 through 2012.

The traditional operating companies have agreements in place from which they expect to receive substantially all of their coal burn requirements in 2013. These agreements have terms ranging between one and eight years. In 2012, the weighted average sulfur content of all coal burned by the traditional operating companies was 0.76 % sulfur. This sulfur level, along with banked and purchased sulfur dioxide allowances, allowed the traditional operating companies to remain within limits set by Phase I of the Clean Air Interstate Rule (CAIR) under the Clean Air Act. In 2012, the Southern Company system did not purchase any sulfur dioxide allowances, annual nitrogen oxide emission allowances, or seasonal nitrogen oxide emission allowances from the market. As any additional environmental regulations are proposed that impact the utilization of coal, the traditional operating companies' fuel mix will be monitored to ensure that the traditional operating companies remain in compliance with applicable laws and regulations. Additionally, Southern Company and the traditional operating companies will continue to evaluate the need to purchase additional emissions allowances, the timing of capital expenditures for emissions control equipment, and potential unit retirements and replacements. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters" of Southern Company, each traditional operating company, and Southern Power in Item 7 herein for additional information on environmental matters.

SCS, acting on behalf of the traditional operating companies and Southern Power, has agreements in place for the natural gas burn requirements of the Southern Company system. For 2013, SCS has contracted for 439 billion cubic feet of natural gas supply under agreements with remaining terms up to eight years. In addition to natural gas supply, SCS has contracts in place for both firm natural gas transportation and storage. Management believes these contracts provide sufficient natural gas supplies, transportation, and storage to ensure normal operations of the Southern Company system's natural gas generating units.

Alabama Power and Georgia Power have numerous contracts covering a portion of their nuclear fuel needs for uranium, conversion services, enrichment services, and fuel fabrication. These contracts have varying expiration dates and most of them are for less than 10 years. Management believes sufficient capacity for nuclear fuel supplies and processing exists to preclude the impairment of normal operations of the Southern Company system's nuclear generating units.

Changes in fuel prices to the traditional operating companies are generally reflected in fuel adjustment clauses contained in rate schedules. See "Rate Matters – Rate Structure and Cost Recovery Plans" herein for additional information. Southern Power's PPAs generally provide that the counterparty is responsible for substantially all of the cost of fuel.

Alabama Power and Georgia Power have contracts with the United States, acting through the DOE, that provide for the permanent disposal of spent nuclear fuel. The DOE failed to begin disposing of spent fuel in 1998, as required by the contracts, and Alabama Power and Georgia Power have pursued and are pursuing legal remedies against the government for breach of contract. See Note 3 to the financial statements of Southern Company, Alabama Power, and Georgia Power under "Nuclear Fuel Disposal Costs" in Item 8 herein for additional information.

Territory Served by the Traditional Operating Companies and Southern Power

The territory in which the traditional operating companies provide electric service comprises most of the states of Alabama and Georgia together with the northwestern portion of Florida and southeastern Mississippi. In this territory there are non-affiliated electric distribution systems that obtain some or all of their power requirements either directly or indirectly from the traditional operating companies. The territory has an area of approximately 120,000 square miles and an estimated population of approximately 16 million. Southern Power sells electricity at market-based rates in the wholesale market primarily to investor-owned utilities, IPPs, municipalities, and electric cooperatives.

Alabama Power is engaged, within the State of Alabama, in the generation and purchase of electricity and the transmission, distribution, and sale of such electricity, at retail in approximately 400 cities and towns (including Anniston, Birmingham,

Gadsden, Mobile, Montgomery, and Tuscaloosa), as well as in rural areas, and at wholesale to 15 municipally-owned electric distribution systems, 11 of which are served indirectly through sales to Alabama Municipal Electric Authority, and two rural distributing cooperative associations. Alabama Power owns coal reserves near its Plant Gorgas and uses the output of coal from the reserves in its generating plants. Alabama Power also sells, and cooperates with dealers in promoting the sale of, electric appliances.

Georgia Power is engaged in the generation and purchase of electricity and the transmission, distribution, and sale of such electricity within the State of Georgia, at retail in over 600 communities (including Athens, Atlanta, Augusta, Columbus, Macon, Rome, and Savannah), as well as in rural areas, and at wholesale currently to OPC, MEAG Power, Dalton, various electric membership corporations, and non-affiliated utilities.

Gulf Power is engaged, within the northwestern portion of Florida, in the generation and purchase of electricity and the transmission, distribution, and sale of such electricity, at retail in 71 communities (including Pensacola, Panama City, and Fort Walton Beach), as well as in rural areas, and at wholesale to a non-affiliated utility.

Mississippi Power is engaged in the generation and purchase of electricity and the transmission, distribution, and sale of such electricity within 23 counties in southeastern Mississippi, at retail in 123 communities (including Biloxi, Gulfport, Hattiesburg, Laurel, Meridian, and Pascagoula), as well as in rural areas, and at wholesale to one municipality, six rural electric distribution cooperative associations, and one generating and transmitting cooperative.

For information relating to KWH sales by customer classification for the traditional operating companies, see MANAGEMENT'S DISCUSSION AND ANALYSIS – RESULTS OF OPERATIONS of each traditional operating company in Item 7 herein. Also, for information relating to the sources of revenues for Southern Company, each traditional operating company, and Southern Power, reference is made to Item 7 herein.

The RUS has authority to make loans to cooperative associations or corporations to enable them to provide electric service to customers in rural sections of the country. There are 71 electric cooperative organizations operating in the territory in which the traditional operating companies provide electric service at retail or wholesale.

One of these organizations, PowerSouth, is a generating and transmitting cooperative selling power to several distributing cooperatives, municipal systems, and other customers in south Alabama and northwest Florida. PowerSouth owns generating units with approximately 2,027 MWs of nameplate capacity, including an undivided 8.16% ownership interest in Alabama Power's Plant Miller Units 1 and 2. PowerSouth's facilities were financed with RUS loans secured by long-term contracts requiring distributing cooperatives to take their requirements from PowerSouth to the extent such energy is available.

Alabama Power and Gulf Power have entered into separate agreements with PowerSouth involving interconnection between their respective systems. The delivery of capacity and energy from PowerSouth to certain distributing cooperatives in the service territories of Alabama Power and Gulf Power is governed by the Southern Company/PowerSouth Network Transmission Service Agreement. The rates for this service to PowerSouth are on file with the FERC. See PROPERTIES – "Jointly-Owned Facilities" in Item 2 herein for details of Alabama Power's joint-ownership with PowerSouth of a portion of Plant Miller.

Four electric cooperative associations, financed by the RUS, operate within Gulf Power's service territory. These cooperatives purchase their full requirements from PowerSouth and SEPA (a federal power marketing agency). A non-affiliated utility also operates within Gulf Power's service territory and purchases its full requirements from Gulf Power.

Mississippi Power has an interchange agreement with SMEPA, a generating and transmitting cooperative, pursuant to which various services are provided, including the furnishing of protective capacity by Mississippi Power to SMEPA. In 2010, Mississippi Power and SMEPA entered into an asset purchase agreement whereby SMEPA agreed to purchase a 17.5% undivided interest in the Kemper IGCC. On February 28, 2012, the Mississippi PSC approved the sale and transfer of 17.5% of the Kemper IGCC to SMEPA. On June 29, 2012, Mississippi Power and SMEPA signed an amendment to the asset purchase agreement whereby SMEPA extended its option to purchase until December 31, 2012 and reduced its purchase commitment percentage from a 17.5% to a 15% undivided interest in the Kemper IGCC, subject to approval by the Mississippi PSC. On September 27, 2012, SMEPA received a conditional loan commitment from the RUS to provide funding for SMEPA's purchase of an undivided interest in the Kemper IGCC. On December 31, 2012, Mississippi Power and SMEPA agreed to extend SMEPA's option to purchase through December 31, 2013. The closing of this transaction is conditioned upon execution of a joint ownership and operating agreement, receipt of all construction permits, appropriate regulatory approvals, financing, and other conditions.

There are also 65 municipally-owned electric distribution systems operating in the territory in which the traditional operating companies provide electric service at retail or wholesale.

Forty-eight municipally-owned electric distribution systems and one county-owned system receive their requirements through MEAG Power, which was established by a Georgia state statute in 1975. MEAG Power serves these requirements from self-

owned generation facilities, some of which are jointly-owned with Georgia Power, and purchases from other resources. MEAG Power also has a pseudo scheduling and services agreement with Georgia Power. Dalton serves its requirements from self-owned generation facilities, some of which are jointly-owned with Georgia Power, and through purchases from Georgia Power and Southern Power through a service agreement. In addition, Georgia Power previously served the full requirements of the City of Hampton's electric distribution system under a market-based contract that terminated on December 31, 2012. See PROPERTIES – "Jointly-Owned Facilities" in Item 2 herein for additional information.

Georgia Power has entered into substantially similar agreements with Georgia Transmission Corporation, MEAG Power, and Dalton providing for the establishment of an integrated transmission system to carry the power and energy of all parties. The agreements require an investment by each party in the integrated transmission system in proportion to its respective share of the aggregate system load. See PROPERTIES – "Jointly-Owned Facilities" in Item 2 herein for additional information.

Southern Power has PPAs with some of the traditional operating companies and with other investor-owned utilities, IPPs, municipalities, electric cooperatives, and an energy marketing firm. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Power Sales Agreements" of Southern Power in Item 7 herein for additional information concerning Southern Power's PPAs.

SCS, acting on behalf of the traditional operating companies, also has a contract with SEPA providing for the use of the traditional operating companies' facilities at government expense to deliver to certain cooperatives and municipalities, entitled by federal statute to preference in the purchase of power from SEPA, quantities of power equivalent to the amounts of power allocated to them by SEPA from certain United States government hydroelectric projects.

Pursuant to the 1956 Utility Act, the Mississippi PSC issued "Grandfather Certificates" of public convenience and necessity to Mississippi Power and to six distribution rural cooperatives operating in southeastern Mississippi, then served in whole or in part by Mississippi Power, authorizing them to distribute electricity in certain specified geographically described areas of the state. The six cooperatives serve approximately 325,000 retail customers in a certificated area of approximately 10,300 square miles. In areas included in a "Grandfather Certificate," the utility holding such certificate may, without further certification, extend its lines up to five miles; other extensions within that area by such utility, or by other utilities, may not be made except upon a showing of, and a grant of a certificate of, public convenience and necessity. Areas included in such a certificate which are subsequently annexed to municipalities may continue to be served by the holder of the certificate, irrespective of whether it has a franchise in the annexing municipality. On the other hand, the holder of the municipal franchise may not extend service into such newly annexed area without authorization by the Mississippi PSC.

Competition

The electric utility industry in the United States is continuing to evolve as a result of regulatory and competitive factors. Among the early primary agents of change was the Energy Policy Act of 1992 which allowed IPPs to access a utility's transmission network in order to sell electricity to other utilities.

The competition for retail energy sales among competing suppliers of energy is influenced by various factors, including price, availability, technological advancements, service, and reliability. These factors are, in turn, affected by, among other influences, regulatory, political, and environmental considerations, taxation, and supply.

The retail service rights of all electric suppliers in the State of Georgia are regulated by the Territorial Electric Service Act of 1973. Pursuant to the provisions of this Act, all areas within existing municipal limits were assigned to the primary electric supplier therein. Areas outside of such municipal limits were either to be assigned or to be declared open for customer choice of supplier by action of the Georgia PSC pursuant to standards set forth in this Act. Consistent with such standards, the Georgia PSC has assigned substantially all of the land area in the state to a supplier. Notwithstanding such assignments, this Act provides that any new customer locating outside of 1973 municipal limits and having a connected load of at least 900 KWs may exercise a one-time choice for the life of the premises to receive electric service from the supplier of its choice.

Generally, the traditional operating companies have experienced, and expect to continue to experience, competition in their respective retail service territories in varying degrees as the result of self-generation (as described below) by customers and other factors.

Southern Power competes with investor owned utilities, IPPs, and others for wholesale energy sales primarily in the Southeastern U.S. wholesale market. The needs of this market are driven by the demands of end users in the Southeast and the generation available. Southern Power's success in wholesale energy sales is influenced by various factors including reliability and availability of Southern Power's plants, availability of transmission to serve the demand, price, and Southern Power's ability to contain costs.

Alabama Power currently has cogeneration contracts in effect with nine industrial customers. Under the terms of these contracts, Alabama Power purchases excess energy generated by such companies. During 2012, Alabama Power purchased

approximately 222 million KWHs from such companies at a cost of $8.6 million.

Georgia Power currently has contracts in effect with 10 small power producers whereby Georgia Power purchases their excess generation. During 2012, Georgia Power purchased 18 million KWHs from such companies at a cost of $0.6 million. Georgia Power also has a PPA for electricity with one cogeneration facility. Payments are subject to reductions for failure to meet minimum capacity output. During 2012, Georgia Power purchased 380 million KWHs at a cost of $27 million from this facility.

Also during 2012, Georgia Power purchased energy from seven customer-owned generating facilities. Six of the seven customers provide only energy to Georgia Power. These six customers make no capacity commitment and are not dispatched by Georgia Power. Georgia Power has a contract with the remaining customer for eight MWs of dispatchable capacity and energy. During 2012, Georgia Power purchased a total of 37 million KWHs from the seven customers at a cost of approximately $1 million.

Gulf Power currently has agreements in effect with various industrial, commercial, and qualifying facilities pursuant to which Gulf Power purchases "as available" energy from customer-owned generation. During 2012, Gulf Power purchased 219 million KWHs from such companies for approximately $6.3 million.

Mississippi Power currently has a cogeneration agreement in effect with one of its industrial customers. Under the terms of this contract, Mississippi Power purchases any excess generation. During 2012, Mississippi Power did not purchase any excess generation from this customer.

Seasonality

The demand for electric power generation is affected by seasonal differences in the weather. At the traditional operating companies and Southern Power, the demand for power peaks during the summer months, with market prices reflecting the demand of power and available generating resources at that time. Power demand peaks can also be recorded during the winter. As a result, the overall operating results of Southern Company, the traditional operating companies, and Southern Power in the future may fluctuate substantially on a seasonal basis. In addition, Southern Company, the traditional operating companies, and Southern Power have historically sold less power when weather conditions are milder.

Regulation

State Commissions

The traditional operating companies are subject to the jurisdiction of their respective state PSCs. The PSCs have broad powers of supervision and regulation over public utilities operating in the respective states, including their rates, service regulations, sales of securities (except for the Mississippi PSC), and, in the cases of the Georgia PSC and the Mississippi PSC, in part, retail service territories. See "Territory Served by the Traditional Operating Companies and Southern Power" and "Rate Matters" herein for additional information.

Federal Power Act

The traditional operating companies, Southern Power and its generation subsidiaries, and SEGCO are all public utilities engaged in wholesale sales of energy in interstate commerce and therefore are subject to the rate, financial, and accounting jurisdiction of the FERC under the Federal Power Act. The FERC must approve certain financings and allows an "at cost standard" for services rendered by system service companies such as SCS and Southern Nuclear. The FERC is also authorized to establish regional reliability organizations which enforce reliability standards, address impediments to the construction of transmission, and prohibit manipulative energy trading practices.

Alabama Power and Georgia Power are also subject to the provisions of the Federal Power Act or the earlier Federal Water Power Act applicable to licensees with respect to their hydroelectric developments. Among the hydroelectric projects subject to licensing by the FERC are 14 existing Alabama Power generating stations having an aggregate installed capacity of 1,662,400 KWs and 18 existing Georgia Power generating stations having an aggregate installed capacity of 1,087,296 KWs.

In 2005, Alabama Power filed two applications with the FERC for new 50-year licenses for its seven hydroelectric developments on the Coosa River (Weiss, Henry, Logan Martin, Lay, Mitchell, Jordan, and Bouldin) and for the Lewis Smith and Bankhead developments on the Warrior River. The FERC licenses for all of these nine projects expired in 2007. Since the FERC did not act on Alabama Power's new license applications prior to the expiration of the existing licenses, the FERC is required by law to issue annual licenses to Alabama Power, under the terms and conditions of the existing licenses, until action is taken on the new license applications.

The FERC issued annual licenses for the Coosa developments and the Warrior River developments in 2007. These annual licenses are automatically renewed each year without further action by the FERC to allow Alabama Power to continue

operation of the projects under the terms of the previous license while the FERC completes review of the applications for new licenses. Though the Coosa application remains pending before the FERC, in 2010, the FERC issued a new 30 year license to Alabama Power for the Warrior River developments. In 2010, the Smith Lake Improvement and Stakeholders' Association filed a request for rehearing of the FERC order granting the new Warrior license. On November 15, 2012 , the FERC denied the Smith Lake Improvement and Stakeholders' Association's request for rehearing. On December 17, 2012, the Smith Lake Improvement and Stakeholders' Association filed for rehearing of the November 15, 2012 order and, on January 16, 2013, the FERC denied the request.

In 2006, Alabama Power initiated the process of developing an application to relicense the Martin Dam Project located on the Tallapoosa River. In June 2011, Alabama Power filed an application with the FERC to relicense the Martin Dam Project. The current Martin license will expire on June 8, 2013.

In 2010, Alabama Power initiated the process of developing an application to relicense the Holt hydroelectric project located on the Warrior River. The current Holt license will expire on August 31, 2015, and the application for a new license is expected to be filed with the FERC no later than August 31, 2013.

In 2007, Georgia Power began the relicensing process for Bartlett's Ferry which is located on the Chattahoochee River near Columbus, Georgia. On December 14, 2012, Georgia Power filed an application with the FERC to relicense the Bartlett's Ferry project. The current Bartlett's Ferry license will expire on December 14, 2014.

The ultimate outcome of these matters cannot be determined at this time. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "FERC Matters" of Alabama Power in Item 7 herein for additional information.

Georgia Power and OPC also have a license, expiring in 2027, for the Rocky Mountain Plant, a pure pumped storage facility of 847,800 KW capacity. See PROPERTIES – "Jointly-Owned Facilities" in Item 2 herein for additional information.

Licenses for all projects, excluding those discussed above, expire in the period 2023-2034 in the case of Alabama Power's projects and in the period 2020-2039 in the case of Georgia Power's projects.

Upon or after the expiration of each license, the U.S. Government, by act of Congress, may take over the project or the FERC may relicense the project either to the original licensee or to a new licensee. In the event of takeover or relicensing to another, the original licensee is to be compensated in accordance with the provisions of the Federal Power Act, such compensation to reflect the net investment of the licensee in the project, not in excess of the fair value of the property, plus reasonable damages to other property of the licensee resulting from the severance therefrom of the property.

Nuclear Regulation

Alabama Power, Georgia Power, and Southern Nuclear are subject to regulation by the NRC. The NRC is responsible for licensing and regulating nuclear facilities and materials and for conducting research in support of the licensing and regulatory process, as mandated by the Atomic Energy Act of 1954, as amended; the Energy Reorganization Act of 1974, as amended; and the Nuclear Nonproliferation Act of 1978; and in accordance with the National Environmental Policy Act of 1969, as amended, and other applicable statutes. These responsibilities also include protecting public health and safety, protecting the environment, protecting and safeguarding nuclear materials and nuclear power plants in the interest of national security, and assuring conformity with antitrust laws.

In 2002, the NRC extended the licenses of Georgia Power's Plant Hatch Units 1 and 2 until 2034 and 2038, respectively. In 2005, the NRC extended the licenses of Alabama Power's Plant Farley Units 1 and 2 until 2037 and 2041, respectively. In 2009, the NRC extended the licenses of Plant Vogtle Units 1 and 2 to 2047 and 2049, respectively.

On February 10, 2012, the NRC issued combined construction and operating licenses (COLs) for Plant Vogtle Units 3 and 4. Receipt of the COLs allowed full construction to begin. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "PSC Matters – Nuclear Construction" of Georgia Power in Item 7 herein and Note 3 to the financial statements of Southern Company under "Retail Regulatory Matters – Georgia Power – Nuclear Construction" and Georgia Power under "Retail Regulatory Matters – Nuclear Construction" in Item 8 herein for additional information.

See Notes 1 and 9 to the financial statements of Southern Company, Alabama Power, and Georgia Power in Item 8 herein for information on nuclear decommissioning costs and nuclear insurance.

Environmental Statutes and Regulations

The Southern Company system's operations are subject to extensive regulation by state and federal environmental agencies under a variety of statutes and regulations governing environmental media, including air, water, and land resources. Compliance with these existing environmental requirements involves significant capital and operating costs, a major portion of which is expected to be recovered through existing ratemaking provisions for the traditional operating companies or market-based rates for Southern Power. There is no assurance, however, that all such costs will be recovered.

Compliance with the federal Clean Air Act and resulting regulations has been, and will continue to be, a significant focus for Southern Company, each traditional operating company, Southern Power, and SEGCO. In addition, existing environmental laws and regulations may be changed or new laws and regulations may be adopted or otherwise become applicable to the Southern Company system, including laws and regulations designed to address air quality, water, management of waste materials and coal combustion byproducts, global climate change, or other environmental and health concerns. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters" of Southern Company and each of the traditional operating companies in Item 7 herein for additional information about the Clean Air Act and other environmental issues, including, but not limited to, the litigation brought by the EPA under the New Source Review provisions of the Clean Air Act, proposed and final regulations related to air quality, water, greenhouse gases, and coal combustion byproducts. Also see MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters" of Southern Power in Item 7 herein for additional information about environmental issues and climate change regulation.

The Southern Company system's ultimate environmental compliance strategy, including potential unit retirement and replacement decisions, and future environmental capital expenditures will be affected by the final requirements of new or revised environmental regulations and regulations relating to global climate change that are promulgated, including the proposed environmental regulations; the outcome of any legal challenges to the environmental rules; the cost, availability, and existing inventory of emissions allowances; and the fuel mix of the electric utilities. Compliance costs may arise from existing unit retirements, installation of additional environmental controls, upgrades to the transmission system, and adding or changing fuel sources for certain existing units. Also see MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters" of Southern Company and each of the traditional operating companies in Item 7 herein for additional information. The ultimate outcome of these matters cannot be determined at this time.

SEGCO is jointly owned by Alabama Power and Georgia Power. As part of its environmental compliance strategy, SEGCO plans to add natural gas as the primary fuel source for its generating units in 2015. The capacity of SEGCO's units is sold equally to Alabama Power and Georgia Power through a PPA. The impact of SEGCO's ultimate compliance strategy on such PPA costs cannot be determined at this time; however, if such costs cannot continue to be recovered by Alabama Power or Georgia Power through retail rates, they could have a material financial impact on the financial statements of Southern Company and the applicable traditional operating company. See Note 4 to the financial statements of Alabama Power and Georgia Power for additional information.

Compliance with any new federal or state legislation or regulations relating to air quality, water, coal combustion byproducts, global climate change, or other environmental and health concerns could significantly affect the Southern Company system. Although new or revised environmental legislation or regulations could affect many areas of the electric utilities' operations, the full impact of any such changes cannot be determined at this time. Additionally, many of the electric utilities' commercial and industrial customers may also be affected by existing and future environmental requirements, which for some may have the potential to ultimately affect their demand for electricity. See "Construction Program" herein for additional information.

Rate Matters

Rate Structure and Cost Recovery Plans

The rates and service regulations of the traditional operating companies are uniform for each class of service throughout their respective service territories. Rates for residential electric service are generally of the block type based upon KWHs used and include minimum charges. Residential and other rates contain separate customer charges. Rates for commercial service are presently of the block type and, for large customers, the billing demand is generally used to determine capacity and minimum bill charges. These large customers' rates are generally based upon usage by the customer and include rates with special features to encourage off-peak usage. Additionally, Alabama Power, Gulf Power, and Mississippi Power are generally allowed by their respective state PSCs to negotiate the terms and cost of service to large customers. Such terms and cost of service, however, are subject to final state PSC approval.

The traditional operating companies recover their respective costs through a variety of forward-looking, cost-based rate mechanisms. Fuel and net purchased energy costs are recovered through specific fuel cost recovery provisions. These fuel cost recovery provisions are adjusted to reflect increases or decreases in such costs as needed or on schedules as required by the

respective PSCs. Approved environmental compliance, storm damage, and certain other costs are recovered at Alabama Power, Gulf Power, and Mississippi Power through specific cost recovery mechanisms approved by their respective PSCs. Certain similar costs at Georgia Power are recovered through various base rate tariffs as approved by the Georgia PSC. Costs not recovered through specific cost recovery mechanisms are recovered at Alabama Power and Mississippi Power through annual, formulaic cost recovery proceedings and at Georgia Power and Gulf Power through base rate proceedings.

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "PSC Matters" of Southern Company and each of the traditional operating companies in Item 7 herein and Note 3 to the financial statements of Southern Company and each of the traditional operating companies under "Retail Regulatory Matters" in Item 8 herein for a discussion of rate matters. Also, see Note 1 to the financial statements of Southern Company and each of the traditional operating companies in Item 8 herein for a discussion of recovery of fuel costs, storm damage costs, and environmental compliance costs through rate mechanisms.

See "Integrated Resource Planning" herein for a discussion of Georgia PSC certification of new demand-side or supply-side resources and decertification of existing demand-side resources for Georgia Power. In addition, see MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "PSC Matters – Nuclear Construction" of Georgia Power in Item 7 herein and Note 3 to the financial statements of Southern Company under "Retail Regulatory Matters – Georgia Power – Nuclear Construction" and Georgia Power under "Retail Regulatory Matters – Nuclear Construction" in Item 8 herein for a discussion of the Georgia Nuclear Energy Financing Act and the Georgia PSC certification of Plant Vogtle Units 3 and 4, which have allowed Georgia Power to recover financing costs for construction of the new nuclear units during the construction period beginning in 2011.

See Note 3 to the financial statements of Southern Company and Mississippi Power under "Integrated Coal Gasification Combined Cycle" in Item 8 herein and MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Integrated Coal Gasification Combined Cycle" of Mississippi Power in Item 7 herein for information on cost recovery plans and a settlement agreement between Mississippi Power and the Mississippi PSC.

The traditional operating companies and Southern Power and its generation subsidiaries are authorized by the FERC to sell power to non-affiliates, including short-term opportunity sales, at market-based prices. Specific FERC approval must be obtained with respect to a market-based contract with an affiliate.

Mississippi Power serves long-term contracts with rural electric cooperative associations and municipalities located in southeastern Mississippi under cost-based electric tariffs which are subject to regulation by the FERC. The contracts with these wholesale customers represented 22% of Mississippi Power's operating revenues in 2012 and are largely subject to rolling 10-year cancellation notices.

Integrated Resource Planning

Each of the traditional operating companies continually evaluates its electric generating resources in order to ensure that it maintains a cost-effective and reliable mix of resources to meet the existing and future demand requirements of its customers. See "Environmental Statutes and Regulations" above for a discussion of existing and potential environmental regulations that may impact the future generating resource needs of the traditional operating companies.

Certain of the traditional operating companies periodically file IRPs with their respective state PSC as discussed below.

Georgia Power

Triennially, Georgia Power must file an IRP with the Georgia PSC that specifies how it intends to meet the future electrical needs of its customers through a combination of demand-side and supply-side resources. The Georgia PSC, under state law, must certify any new demand-side or supply-side resources for Georgia Power to get cost recovery. Once certified, the lesser of actual or certified construction costs and purchased power costs is recoverable through rates. Certified costs may be excluded from recovery only on the basis of fraud, concealment, failure to disclose a material fact, imprudence, or criminal misconduct.

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "PSC Matters – Georgia Power – Rate Plans" of Southern Company and MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "PSC Matters – Integrated Resource Plans" of Georgia Power in Item 7 herein for additional information.

Gulf Power

Annually by April 1, Gulf Power must file a 10-year site plan with the Florida PSC containing Gulf Power's estimate of its power-generating needs in the period and the general location of its proposed power plant sites. The 10-year site plans submitted by the state's electric utilities are reviewed by the Florida PSC and subsequently classified as either "suitable" or "unsuitable." The Florida PSC then reports its findings along with any suggested revisions to the Florida Department of

Environmental Protection for its consideration at any subsequent electrical power plant site certification proceedings. Under Florida law, any 10-year site plans submitted by an electric utility are considered tentative information for planning purposes only and may be amended at any time at the discretion of the utility with written notification to the Florida PSC. At least every five years, the Florida PSC must conduct proceedings to establish numerical goals for all investor-owned electric utilities and certain municipal or cooperative electric utilities in the state to reduce the growth rates of weather-sensitive peak demand, to reduce and control the growth rates of electric consumption, and to increase the conservation of expensive resources, such as petroleum fuels. Overall residential KWs and KWH goals and overall commercial/industrial KWs and KWH goals for each utility are set by the Florida PSC for each year over a 10-year period. The goals are to be based on an estimate of the total cost effective KWs and KWH savings reasonably achievable through demand-side management in each utility's service territory over a 10-year period. Once goals have been set, each affected utility must develop and submit plans and programs to meet the overall goals within its service territory to the Florida PSC for review and approval. Once approved, the utilities are required to submit periodic reports which the Florida PSC then uses to prepare its annual report to the Florida Governor and legislature of the goals that have been established and the progress towards meeting those goals.

Gulf Power's most recent 10-year site plan was classified by the Florida PSC as "suitable" on November 28, 2012. Gulf Power's most recent 10-year site plan and environmental compliance plan identify environmental regulations and potential legislation or regulation that would impose mandatory restrictions on greenhouse gas emissions. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations – Air Quality," "Environmental Matters – Environmental Statutes and Regulations – Coal Combustion Byproducts," and "Environmental Matters – Global Climate Issues" of Gulf Power in Item 7 herein. Gulf Power continues to consider and evaluate various potential planning scenarios for units at each of Gulf Power's coal-fired generating plants. This work indicates that, depending on the final requirements in these anticipated EPA regulations and any legislation or regulations relating to greenhouse gas emissions, as well as estimates of long-term fuel prices, Gulf Power may conclude that it is more economical to retire certain of its coal-fired generating units prior to 2021 and to replace such units with new or purchased capacity.

In 2009, the Florida PSC adopted new numerical conservation goals for Gulf Power along with other electric utilities in the state. The Florida PSC adopted more aggressive goals due in part to the consideration of possible greenhouse gas emissions costs incurred in connection with possible climate change legislation and a change in the manner in which the Florida PSC considers the effect of so-called "free-riders" on the level of conservation reasonably achievable through utility programs. Gulf Power's plans and programs to meet the new goals were submitted to the Florida PSC for review in 2010 and were approved in January 2011. The costs of implementing Gulf Power's conservation plans and programs are recovered through specific conservation recovery rates set annually by the Florida PSC.

The ultimate outcome of these matters cannot be determined at this time.

Mississippi Power

Mississippi Power's 2010 IRP indicated that Mississippi Power plans to construct the Kemper IGCC to meet its identified needs, to add environmental controls at Plant Daniel Units 1 and 2, to defer environmental controls at Plant Watson Units 4 and 5, and to continue operation of the combined cycle Plant Daniel Units 3 and 4. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations – Air Quality" and "Environmental Matters – Global Climate Issues" of Mississippi Power in Item 7 herein. Depending on the final requirements in the anticipated EPA regulations and any legislation or regulation relating to greenhouse gas emissions, as well as estimates of long-term fuel prices, Mississippi Power may conclude that it is more economical to discontinue burning coal at certain coal-fired generating units than to install the required controls. The ultimate outcome of these matters cannot be determined at this time.

Mississippi Baseload Act

In the 2008 regular session of the Mississippi legislature, a bill was passed and signed by the Governor to enhance the Mississippi PSC's authority to facilitate development and construction of base load generation in the State of Mississippi (Baseload Act). The Baseload Act authorizes, but does not require, the Mississippi PSC to adopt a cost recovery mechanism that includes in retail base rates, prior to and during construction, all or a portion of the prudently incurred pre-construction and construction costs incurred by a utility in constructing a base load electric generating plant. Prior to the passage of the Baseload Act, such costs would traditionally be recovered only after the plant was placed in service. The Baseload Act also provides for periodic prudence reviews by the Mississippi PSC and prohibits the cancellation of any such generating plant without the approval of the Mississippi PSC. In the event of cancellation of the construction of the plant without approval of the Mississippi PSC, the Baseload Act authorizes the Mississippi PSC to make a public interest determination as to whether and to what extent the utility will be afforded rate recovery for costs incurred in connection with such cancelled generating plant. There are legal challenges to the constitutionality of the Baseload Act currently pending before the Mississippi Supreme Court. The ultimate impact of this legislation on Southern Company and Mississippi Power will depend on the outcome of any legal

challenges and cannot be determined at this time.

For information regarding Mississippi Power's construction of the Kemper IGCC, see MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Integrated Coal Gasification Combined Cycle" of Mississippi Power in Item 7 herein and Note 3 to the financial statements of Southern Company and Mississippi Power under "Integrated Coal Gasification Combined Cycle" in Item 8 herein.

For information regarding certain legal challenges to the Baseload Act, see Note 3 to the financial statements of Southern Company and Mississippi Power under "Integrated Coal Gasification Combined Cycle – Baseload Act" in Item 8 herein.

The ultimate outcome of these matters cannot be determined at this time.

Employee Relations

The Southern Company system had a total of 26,439 employees on its payroll at December 31, 2012.

	Employees at December 31, 2012
Alabama Power	6,778
Georgia Power	8,094
Gulf Power	1,416
Mississippi Power	1,281
SCS	4,516
Southern Nuclear	4,077
Southern Power*	0
Other	277
Total	26,439

* Southern Power has no employees. Southern Power has agreements with SCS and the traditional operating companies whereby employee services are rendered at amounts in compliance with FERC regulations.

The traditional operating companies have separate agreements with local unions of the IBEW generally covering wages, working conditions, and procedures for handling grievances and arbitration. These agreements apply with certain exceptions to operating, maintenance, and construction employees.

Alabama Power has an agreement with the IBEW covering wages and working conditions, which is in effect through August 15, 2014.

Georgia Power has an agreement with the IBEW covering wages and working conditions, which is in effect through June 30, 2016.

Gulf Power has an agreement with the IBEW covering wages and working conditions, which is in effect through September 14, 2014.

Mississippi Power has an agreement with the IBEW covering wages and working conditions, which is in effect through August 15, 2014. On February 11, 2013, Mississippi Power signed an agreement with the IBEW related to the Kemper IGCC, which is in effect through March 15, 2016.

Southern Nuclear has an agreement with the IBEW covering certain employees at Plants Hatch and Vogtle which is in effect through June 30, 2016. A five-year agreement between Southern Nuclear and the IBEW representing certain employees at Plant Farley is in effect through August 15, 2014.

The agreements also make the terms of the pension plans for the companies discussed above subject to collective bargaining with the unions at either a five-year or a 10-year cycle, depending upon union and company actions.

Item 1A. RISK FACTORS

In addition to the other information in this Form 10-K, including MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL in Item 7 of each registrant, and other documents filed by Southern Company and/or its subsidiaries with the SEC from time to time, the following factors should be carefully considered in evaluating Southern Company and its subsidiaries. Such factors could affect actual results and cause results to differ materially from those expressed in any forward-looking statements made by, or on behalf of, Southern Company and/or its subsidiaries.

UTILITY REGULATORY, LEGISLATIVE, AND LITIGATION RISKS

Southern Company and its subsidiaries are subject to substantial governmental regulation. Compliance with current and future regulatory requirements and procurement of necessary approvals, permits, and certificates may result in substantial costs to Southern Company and its subsidiaries.

Southern Company and its subsidiaries, including the traditional operating companies and Southern Power, are subject to substantial regulation from federal, state, and local regulatory agencies. Southern Company and its subsidiaries are required to comply with numerous laws and regulations and to obtain numerous permits, approvals, and certificates from the governmental agencies that regulate various aspects of their businesses, including rates and charges, service regulations, retail service territories, sales of securities, asset acquisitions and sales, accounting policies and practices, and the operation of fossil-fuel, nuclear, hydroelectric, solar, and biomass generating facilities, as well as transmission and distribution facilities. For example, the rates charged to wholesale customers by the traditional operating companies and by Southern Power must be approved by the FERC. These wholesale rates could be affected absent the ability to conduct business pursuant to FERC market-based rate authority. Additionally, the respective state PSCs must approve the traditional operating companies' requested rates for retail customers. While the retail rates of the traditional operating companies are designed to provide for the full recovery of costs (including a reasonable return on invested capital), there can be no assurance that a state PSC, in a future rate proceeding, will not attempt to alter the timing or amount of certain costs for which recovery is sought or to modify the current authorized rate of return.

Southern Company and its subsidiaries believe the necessary permits, approvals, and certificates have been obtained for their respective existing operations and that their respective businesses are conducted in accordance with applicable laws; however, the impact of any future revision or changes in interpretations of existing regulations or the adoption of new laws and regulations applicable to Southern Company or any of its subsidiaries cannot now be predicted. Changes in regulation or the imposition of additional regulations could influence the operating environment of Southern Company and its subsidiaries and may result in substantial costs.

The Southern Company system's costs of compliance with environmental laws are significant. The costs of compliance with current and future environmental laws, including laws and regulations designed to address air quality, water, coal combustion byproducts, global climate change, renewable energy standards, and other matters and the incurrence of environmental liabilities could negatively impact the net income, cash flows, and financial condition of Southern Company, the traditional operating companies, and/or Southern Power.

The Southern Company system is subject to extensive federal, state, and local environmental requirements which, among other things, regulate air emissions, water usage and discharges, and the management of hazardous and solid waste in order to adequately protect the environment. Compliance with these environmental requirements requires the traditional operating companies and Southern Power to commit significant expenditures for installation of pollution control equipment, environmental monitoring, emissions fees, and permits at substantially all of their respective facilities. These expenditures are significant and Southern Company, the traditional operating companies, and Southern Power expect that they will increase in the future. Through 2012, the traditional operating companies had invested approximately $8.7 billion in environmental capital retrofit projects to comply with these requirements. The EPA has adopted and is in the process of implementing regulations governing the emission of nitrogen oxide, sulfur dioxide, fine particulate matter, mercury, and other air pollutants under the Clean Air Act through the national ambient air quality standards, CAIR, the MATS rule, and other air quality regulations and is in the process of considering additional revisions. In addition, the EPA has proposed additional regulations governing cooling water intake structures and is expected to propose revisions to the effluent guidelines for steam electric generating plants under

the Clean Water Act. The EPA is also evaluating whether additional regulation of coal combustion byproducts (including coal ash and gypsum) is merited under federal solid and hazardous waste laws.

Existing environmental laws and regulations may be revised or new laws and regulations related to air quality, water, coal combustion byproducts, global climate change, or other environmental and health concerns may be adopted or become applicable to the traditional operating companies and/or Southern Power.

In addition, the EPA has determined that emissions of carbon dioxide and other greenhouse gases are regulated pollutants under the Prevention of Significant Deterioration preconstruction permit program and the Title V operating permit program, which both apply to power plants and other commercial and industrial facilities. On April 13, 2012, the EPA published proposed regulations to establish standards of performance for greenhouse gas emissions from new fossil fuel steam electric generating units and has indicated that it will propose standards of performance for existing units in the future.

The Southern Company system's ultimate environmental compliance strategy, including potential unit retirement and replacement decisions, and future environmental capital expenditures will be affected by the final requirements of new or revised environmental regulations and regulations relating to global climate change that are promulgated; the outcome of any legal challenges to the environmental rules; the cost, availability, and existing inventory of emissions allowances; and the fuel mix of the electric utilities. Compliance costs may arise from existing unit retirements, installation of additional environmental controls, upgrades to the transmission system, and adding or changing fuel sources for certain existing units. Additionally, if Southern Company, any traditional operating company, or Southern Power fails to comply with environmental laws and regulations, even if caused by factors beyond its control, that failure may result in the assessment of civil or criminal penalties and fines. The EPA has filed civil actions against Alabama Power and Georgia Power and issued notices of violation to Gulf Power and Mississippi Power alleging violations of the new source review provisions of the Clean Air Act. Southern Company, the traditional operating companies, and Southern Power are also parties to suits alleging that emissions of carbon dioxide, a greenhouse gas, contribute to global climate change. An adverse outcome in any of these matters could require substantial capital expenditures that cannot be determined at this time and could possibly require payment of substantial penalties.

Compliance costs related to federal and state environmental statutes and regulations could affect earnings if such costs cannot continue to be fully recovered in rates on a timely basis. Environmental compliance spending over the next several years may differ materially from the amounts estimated. The timing, specific requirements, and estimated costs could change as environmental statutes and regulations are adopted or modified. Such expenditures could affect unit retirement and replacement decisions and results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates for the traditional operating companies or market-based rates for Southern Power. Further, higher costs that are recovered through regulated rates could contribute to reduced demand for electricity, which could negatively affect results of operations, cash flows, and financial condition.

Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements such as air quality and water standards, has increased generally throughout the U.S. In particular, personal injury, property damage, and other claims for damages alleged to have been caused by CO_2 and other emissions, coal combustion byproducts, and alleged exposure to hazardous materials, and/or requests for injunctive relief in connection with such matters, have become more frequent.

The ultimate cost impact of proposed and final legislation and regulations and litigation are likely to result in significant and additional costs and could result in additional operating restrictions.

The net income of Southern Company, the traditional operating companies, and Southern Power could be negatively impacted by changes in regulations related to transmission planning processes and competition in the wholesale electric markets.

The traditional operating companies currently own and operate transmission facilities as part of a vertically integrated utility. A small percentage of transmission revenues are collected through the wholesale electric tariff but the majority of transmission revenues are collected through retail rates. Proposed or potential changes in federal law, regulatory uncertainty, and industry restructuring are expected to continue to present challenges to the regulatory and/or operational structure of transmission and competition on the wholesale level. Any changes could have an adverse impact on the ownership of transmission assets and/or future revenues. As an example, pending FERC regulation pertaining to cost allocation for regional transmission projects could require Southern Company and its utility subsidiaries to subsidize costs outside of the Southern Company system's retail service territory.

The FERC rules related to transmission are intended to spur the development of new transmission infrastructure to promote and encourage the integration of renewable sources of supply as well as facilitate competition in the wholesale market by providing more choices to wholesale power customers. In addition to the impacts on transactions contemplating physical delivery of energy, financial laws and regulations also impact power hedging and trading based on futures contracts and derivatives that are traded on various commodities exchanges as well as over-the-counter. Finally, technology changes in the power and fuel industries continue to create significant impacts to wholesale transaction cost structures. Southern Company, the traditional operating companies, and Southern Power cannot predict the impact of these and other such developments, nor can they predict the effect of changes in levels of wholesale supply and demand, which are typically driven by factors beyond their control. The financial condition, net income, and cash flows of Southern Company, the traditional operating companies, and Southern Power could be adversely affected by these and other changes.

The traditional operating companies and Southern Power could be subject to higher costs and penalties as a result of mandatory reliability standards.

Owners and operators of bulk power systems, including the traditional operating companies, are subject to mandatory reliability standards enacted by the North American Reliability Corporation and enforced by the FERC. Compliance with the mandatory reliability standards may subject the traditional operating companies, Southern Power, and Southern Company to higher operating costs and may result in increased capital expenditures. If any traditional operating company or Southern Power is found to be in noncompliance with the mandatory reliability standards, such traditional operating company or Southern Power could be subject to sanctions, including substantial monetary penalties.

OPERATIONAL RISKS

The financial performance of Southern Company and its subsidiaries may be adversely affected if the subsidiaries are unable to successfully operate their facilities or perform certain corporate functions.

The financial performance of Southern Company and its subsidiaries depends on the successful operation of its subsidiaries' electric generating, transmission, and distribution facilities. Operating these facilities involves many risks, including:

- operator error or failure of equipment or processes, particularly with older generating facilities;
- operating limitations that may be imposed by environmental or other regulatory requirements;
- labor disputes;
- terrorist attacks;
- fuel or material supply interruptions;
- compliance with mandatory reliability standards, including mandatory cyber security standards;
- implementation of technologies with which the Southern Company system is developing experience;
- information technology system failure;
- cyber intrusion; and
- catastrophic events such as fires, earthquakes, explosions, floods, droughts, hurricanes, pandemic health events such as influenzas, or other similar occurrences.

A decrease or elimination of revenues from the electric generation, transmission, or distribution facilities or an increase in the cost of operating the facilities would reduce the net income and cash flows and could adversely impact the financial condition of the affected traditional operating company or Southern Power and of Southern Company. In addition, an investment in a subsidiary with such generation, transmission, or distribution facilities could be adversely impacted.

Operation of nuclear facilities involves inherent risks, including environmental, health, regulatory, natural disasters, terrorism, and financial risks, that could result in fines or the closure of the nuclear units owned by Alabama Power or Georgia Power and which may present potential exposures in excess of insurance coverage.

Alabama Power owns, and contracts for the operation of, two nuclear units and Georgia Power holds undivided interests in, and contracts for the operation of, four existing nuclear units. The six existing units are operated by Southern Nuclear and represent approximately 3,680 MWs, or 8.0%, of Southern Company's generation capacity as of December 31, 2012. In addition, Southern Nuclear, on behalf of Georgia Power and the other co-owners, is overseeing the construction of Plant Vogtle Units 3 and 4. Due solely to the increase in nuclear generating capacity, the below risks are expected to increase once Plant Vogtle Units 3 and 4 are operational. Nuclear facilities are subject to environmental, health, and financial risks such as:

- the potential harmful effects on the environment and human health resulting from a release of radioactive materials in connection with the operation of nuclear facilities and the storage, handling, and disposal of spent nuclear fuel;
- uncertainties with respect to the on-site storage of and the ability to dispose of spent nuclear fuel;
- uncertainties with respect to the technological and financial aspects of decommissioning nuclear plants at the end of licensed lives and the ability to maintain adequate reserves for decommissioning;
- limitations on the amounts and types of insurance commercially available to cover losses that might arise in connection with the nuclear operations of Alabama Power and Georgia Power or those of others in the United States;
- potential liabilities arising out of the operation of these facilities;
- significant capital expenditures relating to maintenance, operation, security, and repair of these facilities, including repairs and upgrades required by the NRC;
- the threat of a possible terrorist attack; and
- the impact of a natural disaster.

Alabama Power and Georgia Power maintain decommissioning trusts and external insurance coverage to minimize the financial exposure to these risks; however, it is possible that damages could exceed the amount of insurance coverage.

The NRC has broad authority under federal law to impose licensing and safety-related requirements for the operation of nuclear generation facilities. As a result of the major earthquake and tsunami that struck Japan in March 2011 and caused substantial damage to the nuclear generating units at the Fukushima Daiichi generating plant, the NRC is performing additional operational and safety reviews of nuclear facilities in the U.S., which could potentially impact future operations and capital requirements. The NRC also issued three orders and the NRC staff issued guidance on acceptable approaches for compliance with these orders before the December 31, 2016 deadline, that included, among other items, additional mitigation strategies for beyond-design-basis events, enhanced spent fuel pool instrumentation capabilities, hardened vents for certain classes of containment structures, including the one in use at Plant Hatch, site specific evaluations for seismic and flooding hazards, and various plant evaluations to ensure adequate coping capabilities during station blackout and other conditions. The final form and the resulting impact of any changes to safety requirements for nuclear reactors will be dependent on further review and action by the NRC and cannot be determined at this time.

In the event of non-compliance with NRC licensing and safety-related requirements, the NRC has the authority to impose fines and/or shut down any unit, depending upon its assessment of the severity of the situation, until compliance is achieved. NRC orders or regulations related to increased security measures and any future safety requirements promulgated by the NRC could require Alabama Power and Georgia Power to make substantial operating and capital expenditures at their nuclear plants. In addition, although Alabama Power, Georgia Power, and Southern Company have no reason to anticipate a serious nuclear incident at the Southern Company system nuclear plants, if an incident did occur, it could result in substantial costs to Alabama Power or Georgia Power and Southern Company. A major incident at a nuclear facility anywhere in the world could cause the NRC to limit or prohibit the operation or licensing of any domestic nuclear unit. Moreover, a major incident at any nuclear facility in the United States could require Alabama Power and Georgia Power to make material contributory payments.

In addition, potential terrorist threats and increased public scrutiny of utilities could result in increased nuclear licensing or compliance costs that are difficult to predict.

Physical or cyber attacks, both threatened and actual, could impact the ability of the traditional operating companies and Southern Power to operate and could adversely affect financial results and liquidity.

The traditional operating companies and Southern Power face the risk of physical and cyber attacks, both threatened and actual, against their respective generation facilities, the transmission and distribution infrastructure used to transport power, and their information technology systems and network infrastructure, which could negatively impact the ability of the traditional operating companies or Southern Power to generate, transport, and deliver power, or otherwise operate their respective facilities in the most efficient manner or at all.

The traditional operating companies and Southern Power operate in a highly regulated industry that requires the continued operation of sophisticated information technology systems and network infrastructure, which are part of an interconnected regional grid. In addition, in the ordinary course of business, the traditional operating companies and Southern Power collect and retain sensitive information including personal identification information about customers and employees and other confidential information. The traditional operating companies and Southern Power face on-going threats to their business networks. Despite the implementation of robust security measures, all technology systems are potentially vulnerable to disability, failures, or unauthorized access due to human error or physical or cyber attacks. If the traditional operating companies' or Southern Power's technology systems were to fail or be breached and were not recovered in a timely way, the traditional operating companies or Southern Power may be unable to fulfill critical business functions, and sensitive and other data could be compromised. The theft, damage, or improper disclosure of sensitive electronic data may also subject the applicable traditional operating company or Southern Power to penalties and claims from third parties.

These events could negatively affect the financial results of Southern Company, the traditional operating companies, or Southern Power through lost revenues, costs to recover and repair damage, and costs associated with governmental actions in response to such attacks.

The traditional operating companies and Southern Power may not be able to obtain adequate fuel supplies, which could limit their ability to operate their facilities.

The traditional operating companies and Southern Power purchase fuel, including coal, natural gas, uranium, fuel oil, and biomass, from a number of suppliers. Disruption in the delivery of fuel, including disruptions as a result of, among other things, transportation delays, weather, labor relations, force majeure events, or environmental regulations affecting any of these fuel suppliers, could limit the ability of the traditional operating companies and Southern Power to operate their respective facilities, and thus reduce the net income of the affected traditional operating company or Southern Power and Southern Company.

The traditional operating companies are dependent on coal for a portion of their electric generating capacity. Each traditional operating company has coal supply contracts in place; however, there can be no assurance that the counterparties to these agreements will fulfill their obligations to supply coal to the traditional operating companies. The suppliers under these agreements may experience financial or technical problems which inhibit their ability to fulfill their obligations to the traditional operating companies. In addition, the suppliers under these agreements may not be required to supply coal to the traditional operating companies under certain circumstances, such as in the event of a natural disaster. If the traditional operating companies are unable to obtain their coal requirements under these contracts, the traditional operating companies may be required to purchase their coal requirements at higher prices, which may not be fully recoverable through rates.

In addition, the traditional operating companies and Southern Power to a greater extent are dependent on natural gas for a portion of their electric generating capacity. In many instances, the cost of purchased power for the traditional operating companies and Southern Power is influenced by natural gas prices. Historically, natural gas prices have been more volatile than prices of other fuels. In recent years, domestic natural gas prices have been depressed by robust supplies, including production from shale gas, as well as lower demand. These market conditions, together with additional regulation of coal-fired generating units, have increased the traditional operating companies' reliance on natural gas-fired generating units.

Natural gas supplies can be subject to disruption in the event production or distribution is curtailed, such as in the event of a hurricane. The availability of shale gas and potential regulations affecting its accessibility may have a material impact on the supply and cost of natural gas.

In addition, world market conditions for fuels can impact the cost and availability of natural gas, coal, and uranium.

The revenues of Southern Company, the traditional operating companies, and Southern Power depend in part on sales under PPAs. The failure of a counterparty to one of these PPAs to perform its obligations, or the failure to renew the PPAs, could have a negative impact on the net income and cash flows of the affected traditional operating company or Southern Power and of Southern Company.

Most of Southern Power's generating capacity has been sold to purchasers under PPAs. In addition, the traditional operating companies enter into PPAs with non-affiliated parties. Revenues are dependent on the continued performance by the purchasers of their obligations under these PPAs. Even though Southern Power and the traditional operating companies have a rigorous credit evaluation process and contractual protections, the failure of one of the purchasers to perform its obligations could have a negative impact on the net income and cash flows of the affected traditional operating company or Southern Power and of Southern Company. Although these credit evaluations and contractual protections take into account the possibility of default by a purchaser, actual exposure to a default by a purchaser may be greater than predicted. Additionally, neither Southern Power nor any traditional operating company can predict whether the PPAs will be renewed at the end of their respective terms or on what terms any renewals may be made. If a PPA is not renewed, a replacement PPA cannot be assured.

Changes in technology may make Southern Company's electric generating facilities owned by the traditional operating companies and Southern Power less competitive.

A key element of the business models of Southern Company, the traditional operating companies, and Southern Power is that generating power at central station power plants achieves economies of scale and produces power at a competitive cost. There are distributed generation technologies that produce power, including fuel cells, microturbines, wind turbines, and solar cells. It is possible that advances in technology will reduce the cost of alternative methods of producing power to a level that is competitive with that of most central station power electric production. If these technologies became cost competitive and achieved economies of scale, the market share of the traditional operating companies and Southern Power could be eroded, and the value of their respective electric generating facilities could be reduced. It is also possible that rapid advances in central station power generation technology could reduce the value of the current electric generating facilities owned by the traditional operating companies and Southern Power. Changes in technology could also alter the channels through which electric customers buy or utilize power, which could reduce the revenues or increase the expenses of Southern Company, the traditional operating companies, or Southern Power.

Failure to attract and retain an appropriately qualified workforce could negatively impact Southern Company's and its subsidiaries' results of operations.

Events such as an aging workforce without appropriate replacements, mismatch of skill sets to future needs, or unavailability of contract resources may lead to operating challenges or increased costs. Such operating challenges include lack of resources, loss of knowledge, and a lengthy time period associated with skill development, especially with the workforce needs associated with new nuclear and IGCC construction. Failure to hire and adequately obtain replacement employees, including the ability to transfer significant internal historical knowledge and expertise to the new employees, or the future availability and cost of contract labor may adversely affect Southern Company and its subsidiaries' ability to manage and operate their businesses. If Southern Company and its subsidiaries, including the traditional operating companies, are unable to successfully attract and retain an appropriately qualified workforce, results of operations could be negatively impacted.

CONSTRUCTION RISKS

Southern Company, the traditional operating companies, and/or Southern Power may incur additional costs or delays in the construction of new plants or other facilities and may not be able to recover their investments. Also, existing facilities of the traditional operating companies and Southern Power require ongoing capital expenditures, including those to meet environmental standards.

The businesses of the registrants require substantial capital expenditures for investments in new facilities and capital improvements to transmission, distribution, and generation facilities, including those to meet environmental standards. Certain of the traditional operating companies and Southern Power are in the process of constructing new generating facilities and adding environmental controls equipment at existing generating facilities. The Southern Company system intends to continue its strategy of developing and constructing other new facilities, expanding existing facilities, and adding environmental control equipment. These types of projects are long-term in nature and in some cases involve facility designs that have not been

finalized or previously constructed. The completion of these types of projects without delays or significant cost overruns is subject to substantial risks, including:

- shortages and inconsistent quality of equipment, materials, and labor;
- work stoppages;
- contractor or supplier delay or non-performance under construction or other agreements or non-performance by other major participants in construction projects;
- delays in or failure to receive necessary permits, approvals, and other regulatory authorizations;
- impacts of new and existing laws and regulations, including environmental laws and regulations;
- the outcome of legal challenges to regulatory approvals;
- failure to construct in accordance with licensing requirements;
- continued public and policymaker support for such projects;
- adverse weather conditions;
- unforeseen engineering problems;
- changes in project design or scope;
- environmental and geological conditions;
- delays or increased costs to interconnect facilities to transmission grids; and
- unanticipated cost increases, including materials and labor, and increased financing costs as a result of changes in market interest rates or as a result of construction schedule delays.

In addition, with respect to the construction of new nuclear units and the operation of existing nuclear units, a major incident at a nuclear facility anywhere in the world could cause the NRC to delay or prohibit construction of new nuclear units or require additional safety measures at new and existing units. As a result of the major earthquake and tsunami that struck Japan in March 2011 and caused substantial damage to the nuclear generating units at the Fukushima Daiichi generating plant, the NRC is performing additional operational and safety reviews of nuclear facilities in the U.S., which could potentially impact future operations and capital requirements.

If a traditional operating company or Southern Power is unable to complete the development or construction of a facility or decides to delay or cancel construction of a facility, it may not be able to recover its investment in that facility and may incur substantial cancellation payments under equipment purchase orders or construction contracts. Even if a construction project is completed, the total costs may be higher than estimated and there is no assurance that the traditional operating company will be able to recover such expenditures through regulated rates. In addition, construction delays and contractor performance shortfalls can result in the loss of revenues and may, in turn, adversely affect the net income and financial position of a traditional operating company or Southern Power and of Southern Company.

Construction delays also may result in the loss of otherwise available investment tax credits, production tax credits, and other tax incentives. Furthermore, if construction projects are not completed according to specification, a traditional operating company or Southern Power and Southern Company may incur liabilities and suffer reduced plant efficiency, higher operating costs, and reduced net income.

Once facilities come into commercial operation, ongoing capital expenditures are required to maintain reliable levels of operation. Significant portions of the traditional operating companies' existing facilities were constructed many years ago. Older generation equipment, even if maintained in accordance with good engineering practices, may require significant capital expenditures to maintain efficiency, to comply with changing environmental requirements, or to provide reliable operations.

The two largest construction projects currently underway in the Southern Company system are the construction of Plant Vogtle Units 3 and 4 and the construction of the Kemper IGCC. Southern Nuclear, on behalf of Georgia Power and the other co-owners, is overseeing the construction of and will operate Plant Vogtle Units 3 and 4 (each, an approximately 1,100 MW AP1000 nuclear generating unit). Georgia Power owns 45.7% of the new units. The NRC certified the Westinghouse Electric Company LLC's Design Certification Document, as amended (DCD), for the AP1000 reactor design, effective December 30, 2011, and issued combined COLs on February 10, 2012. Receipt of the COLs allowed full construction to begin. Separate groups of petitioners have filed petitions in the U.S. Court of Appeals for the District of Columbia Circuit seeking judicial review of the NRC's issuance of the COLs and certification of the DCD. Additional technical and procedural challenges to the construction and licensing of Plant Vogtle Units 3 and 4, at the federal and state level, are expected as construction proceeds.

Georgia Power is required to file semi-annual Vogtle Construction Monitoring (VCM) reports with the Georgia PSC by February 28 and August 31 of each year. Georgia Power's eighth VCM report requests approval for an additional $0.2 billion of construction capital costs incurred through December 31, 2012. If the projected certified construction capital costs to be borne by Georgia Power increase by 5% or the projected in-service dates are significantly extended, Georgia Power is required to seek an amendment to the Plant Vogtle Units 3 and 4 certificate from the Georgia PSC. Accordingly, the eighth VCM also requests an amendment to the certificate to increase the estimated in-service capital cost of Plant Vogtle Units 3 and 4 to $4.8 billion and to extend the estimated in-service dates to fourth quarter 2017 and fourth quarter 2018 for Plant Vogtle Units 3 and 4, respectively. Associated financing costs during the construction period are estimated to total approximately $2.0 billion.

Georgia Power, OPC, MEAG Power, and the City of Dalton (collectively, the Owners) and Westinghouse Electric Company LLC (Westinghouse) and Stone & Webster, Inc. (Stone & Webster) (collectively, the Contractor) are involved in litigation regarding the costs associated with design changes to the DCD and delays in the timing of approval of the DCD and issuance of the COLs, including the assertion by the Contractor that the Owners are responsible for these costs and that the Contractor is entitled to further schedule extensions. Georgia Power has not agreed with either the proposed cost or schedule adjustments or that the Owners have any responsibility for costs related to these issues. While litigation has commenced and Georgia Power intends to vigorously defend its positions, Georgia Power expects negotiations with the Contractor to continue with respect to costs and schedule during which negotiations the parties may reach a mutually acceptable compromise of their positions.

In addition, there are processes in place that are designed to assure compliance with the requirements specified in the DCD and COLs, including rigorous inspections by Southern Nuclear and the NRC that occur throughout construction. License amendment requests are pending with the NRC to address a few non-safety significant deviations that were identified in the fourth quarter of 2012 with respect to the rebar design for the Plant Vogtle Unit 3 nuclear island. Various design and other issues are expected to arise as construction proceeds, which may result in additional license amendments or require other resolution. If any license amendment requests are not resolved in a timely manner, there may be delays in the project schedule that could result in increased costs either to the Owners, the Contractor, or both.

As construction continues, additional delays in the fabrication and assembly of structural modules or the failure of such modules to meet applicable standards, or other issues may further impact project schedule and costs. Additional claims by the Contractor or Georgia Power (on behalf of the Owners) are also likely to arise throughout construction. These claims may be resolved through formal and informal dispute resolution procedures under the Vogtle 3 and 4 Agreement, but also may be resolved through litigation.

In addition, Mississippi Power is constructing the Kemper IGCC. Mississippi Power and SMEPA are parties to an amended Asset Purchase Agreement whereby SMEPA agreed to purchase a 15% undivided interest in the Kemper IGCC. The closing of this transaction is conditioned upon execution of a joint ownership and operating agreement, receipt of all construction permits, appropriate regulatory approvals, financing, and other conditions.

The Mississippi PSC originally approved Mississippi Power's request for a CPCN for the construction of the Kemper IGCC in 2010. Following judicial proceedings relating to its original order, the Mississippi PSC issued a detailed order (2012 MPSC Order) confirming the CPCN for the Kemper IGCC. On April 26, 2012, the Sierra Club appealed the 2012 MPSC Order to the Chancery Court of Harrison County, Mississippi (Chancery Court). On December 17, 2012, the Chancery Court affirmed the 2012 MPSC Order which confirmed the issuance of the CPCN for the Kemper IGCC. On January 8, 2013, the Sierra Club filed an appeal of the Chancery Court's ruling with the Mississippi Supreme Court. Additional judicial challenges that may impact the Kemper IGCC are pending, including a challenge of the constitutionality of the Baseload Act that is pending before the Mississippi Supreme Court.

The certificated cost estimate of the Kemper IGCC included in the 2012 MPSC Order was $2.4 billion, net of $245.3 million of grants awarded to the project by the DOE under the Clean Coal Power Initiative Round 2 (CCPI2) and excluding the cost of the

lignite mine and equipment, the cost of the CO_2 pipeline facilities, and financing costs related to the Kemper IGCC. The 2012 MPSC Order approved a construction cost cap of up to $2.88 billion, with recovery of prudently-incurred costs subject to approval by the Mississippi PSC. Exemptions from the cost cap included in the 2012 Mississippi PSC Order included the cost of the lignite mine and equipment, the cost of the CO_2 pipeline facilities, financing costs, and certain general exceptions, including change of law, force majeure, and beneficial capital (which exists when Mississippi Power demonstrates that the purpose and effect of the construction cost increase is to produce efficiencies that will result in a neutral or favorable effect on the ratepayers, relative to the original proposal for the CPCN).

Mississippi Power's current cost estimate for the Kemper IGCC (net of the $245.3 million CCPI2 grant, and excluding the cost of the lignite mine and equipment, the cost of the CO_2 pipeline facilities, financing costs, and certain general exceptions as contemplated in the 2012 Mississippi PSC Order and the settlement agreement between Mississippi Power and the Mississippi PSC entered into on January 24, 2013 (Settlement Agreement) that must be specifically approved by the Mississippi PSC) is approximately $2.88 billion. While Mississippi Power continues to believe its cost estimate and schedule projection remain appropriate based on the current status of the project, it is possible that Mississippi Power could experience further cost increases and/or schedule delays with respect to the Kemper IGCC. Certain factors have caused and may continue to cause the costs for the Kemper IGCC to increase and/or schedule delays to occur including, but not limited to, costs and productivity of labor, adverse weather conditions, shortages and inconsistent quality of equipment, materials, and labor, contractor or supplier delay or non-performance under construction or other agreements, and unforeseen engineering problems. To the extent it becomes probable that costs beyond any permitted exceptions to the cost cap will exceed $2.88 billion or it becomes probable that the Mississippi PSC will disallow a portion of the costs relating to the Kemper IGCC, including certain general exceptions as contemplated in the 2012 Mississippi PSC order and the Settlement Agreement, charges to expense may occur and these charges could be material.

The 2012 MPSC Order included provisions relating to both Mississippi Power's recovery of financing costs during the course of construction of the Kemper IGCC and Mississippi Power's recovery of costs following the in-service date of the Kemper IGCC. On June 22, 2012, the Mississippi PSC denied Mississippi Power's proposed Certificated New Plant-A (CNP-A) rate schedule and the 2012 rate recovery filings submitted by Mississippi Power which provided for recovery of financing costs during 2012, pending a final ruling from the Mississippi Supreme Court regarding the Sierra Club's appeal of the Mississippi PSC's issuance of the CPCN for the Kemper IGCC. On July 9, 2012, Mississippi Power appealed the Mississippi PSC's June 22, 2012 decision to the Mississippi Supreme Court and requested interim rates under bond of $55.3 million.

On January 24, 2013, Mississippi Power and the Mississippi PSC entered into a Settlement Agreement that (1) establishes the process for resolving matters regarding cost recovery related to the Kemper IGCC for the purpose of mitigating risks to Mississippi Power and its customers and expediting the regulatory process associated with future rate filings required under the Settlement Agreement and (2) resolves Mississippi Power's CNP-A rate appeal before the Mississippi Supreme Court.

On February 12, 2013, the Mississippi Supreme Court granted Mississippi Power and the Mississippi PSC's joint filing for dismissal of Mississippi Power's appeal of the Mississippi PSC's June 22, 2012 decision.

Under the terms of the Settlement Agreement, Mississippi Power and the Mississippi PSC will follow certain agreed-upon regulatory procedures and schedules for resolving the cost recovery matters related to the Kemper IGCC. These procedures and schedules include the following: (1) Mississippi Power's filing within 30 days of the Settlement Agreement of a new request to increase rates in 2013 in an amount not to exceed a $172 million annual revenue requirement, based upon projected investment as of December 31, 2013, to be recorded to a regulatory liability to be used to mitigate rate impacts when the Kemper IGCC is placed in service (which filing for $172 million was made on January 25, 2013); (2) the Mississippi PSC's decision on that matter within 50 days of Mississippi Power's request; (3) Mississippi Power's collaboration with the Mississippi Public Utilities Staff to file with the Mississippi PSC within three months of the Settlement Agreement a rate recovery plan for the Kemper IGCC for the first seven years of its operation, along with a proposed revenue requirement under such plan for 2014 through 2020 (which filing was made on February 26, 2013 as described below); (4) the Mississippi PSC's decision on the rate recovery plan within four months of the filing; (5) Mississippi Power's agreement to limit the portion of prudently-incurred Kemper IGCC costs to be included in rate base to the $2.4 billion certificated cost estimate, plus costs related to the lignite mine and CO_2 pipeline as well as any other costs permitted or determined to be excluded from the cost cap, provided that this limitation will not prevent Mississippi Power from securing alternate financing to recover any prudently-incurred Kemper IGCC costs, including financing costs and plant costs above the $2.4 billion certificated cost estimate, not otherwise recovered in any Mississippi PSC rate proceeding contemplated by the Settlement Agreement; and (6) the Mississippi PSC's completion of its prudence review of the Kemper IGCC costs incurred through 2012 within six months of the Settlement Agreement, an additional prudence review upon considering the seven-year rate plan for costs incurred through the most recent reporting period, and a final prudence review of the remaining project costs within six months of the Kemper IGCC's in-service date.

Legislation to authorize a multi-year rate plan and legislation to provide for alternate financing through securitization was passed in the Mississippi legislature and was signed by the Governor on February 26, 2013. Mississippi Power contemplates using securitization as provided in the legislation as its form of alternate financing for prudently-incurred Kemper IGCC costs, including financing costs and plant costs above the $2.4 billion certificated cost estimate, not otherwise recovered in any Mississippi PSC rate proceeding contemplated by the Settlement Agreement.

On February 26, 2013, Mississippi Power in compliance with the Settlement Agreement, filed with the Mississippi PSC a rate recovery plan for the Kemper IGCC for 2014 through 2020, the first seven years of operation of the Kemper IGCC. The rate recovery plan proposes recovery of an annual revenue requirement of approximately $150 million of Kemper IGCC-related operational costs and rate base amounts, including plant costs equal to the $2.4 billion certificated cost estimate. Approval of Mississippi Power's request to increase rates in 2013 to mitigate the rate impacts of the Kemper IGCC filed on January 25, 2013 is integral to the rate recovery plan as the proposed filing contemplates amortization of the regulatory liability to be used to mitigate rate impacts from 2014 through 2020, based on a fixed amortization schedule that requires approval by the Mississippi PSC. Under the rate recovery plan filing, Mississippi Power proposes annual recovery to remain the same from 2014 through 2020 and, while it is the intent of Mississippi Power for the actual revenue requirement to equal the proposed revenue requirement for certain items, Mississippi Power proposes that the annual differences for those items through 2020 will be deferred, subject to accrual of carrying costs, and the cumulative balance will be reviewed at the end of the term of the Settlement Agreement by the Mississippi PSC for determination of the manner of the recovery. Mississippi Power proposes to secure recovery of prudently-incurred Kemper IGCC costs, including financing costs and plant costs above the $2.4 billion certificated cost estimate, not otherwise recovered in any Mississippi PSC rate proceeding contemplated by the Settlement Agreement to be provided for with alternate financing through securitization. The rate recovery necessary to recover the annual costs of securitization is proposed to be filed and begin after the Kemper IGCC is placed in service.

Under the terms of the Settlement Agreement, Mississippi Power has the right to terminate the Settlement Agreement if certain conditions, including the passage of multi-year rate plan legislation that is contemplated under the Settlement Agreement, are not met, if Mississippi Power is unable to secure alternate financing for any prudently-incurred Kemper IGCC costs not otherwise recovered in any Mississippi PSC rate proceeding contemplated by the Settlement Agreement, or if the Mississippi PSC fails to comply with the requirements of the Settlement Agreement.

The ultimate outcome of these matters, including the determinations of prudency and the specific manner of recovery of prudently-incurred costs, is subject to further legislative and regulatory actions and cannot be determined at this time.

FINANCIAL, ECONOMIC, AND MARKET RISKS

The generation operations and energy marketing operations of Southern Company, the traditional operating companies, and Southern Power are subject to risks, many of which are beyond their control, including changes in power prices and fuel costs, that may reduce Southern Company's, the traditional operating companies', and/or Southern Power's revenues and increase costs.

The generation operations and energy marketing operations of the Southern Company system are subject to changes in power prices or fuel costs, which could increase the cost of producing power or decrease the amount received from the sale of power. The market prices for these commodities may fluctuate significantly over relatively short periods of time. In addition, the proportion of natural gas generation to the total fuel mix is likely to increase in the future. The Southern Company system attempts to mitigate risks associated with fluctuating fuel costs by passing these costs on to customers through the traditional operating companies' fuel cost recovery clauses or through PPAs. Among the factors that could influence power prices and fuel costs are:

- prevailing market prices for coal, natural gas, uranium, fuel oil, biomass, and other fuels used in the generation facilities of the traditional operating companies and Southern Power, including associated transportation costs, and supplies of such commodities;
- demand for energy and the extent of additional supplies of energy available from current or new competitors;
- liquidity in the general wholesale electricity market;
- weather conditions impacting demand for electricity;
- seasonality;

- transmission or transportation constraints or inefficiencies;
- availability of competitively priced alternative energy sources;
- forced or unscheduled plant outages for the Southern Company system, its competitors, or third party providers;
- the financial condition of market participants;
- the economy in the service territory, the nation, and worldwide, including the impact of economic conditions on demand for electricity and the demand for fuels;
- natural disasters, wars, embargos, acts of terrorism, and other catastrophic events; and
- federal, state, and foreign energy and environmental regulation and legislation.

Certain of these factors could increase the expenses of the traditional operating companies or Southern Power and Southern Company. For the traditional operating companies, such increases may not be fully recoverable through rates. Other of these factors could reduce the revenues of the traditional operating companies or Southern Power and Southern Company.

Historically, the traditional operating companies from time to time have experienced underrecovered fuel cost balances and deficits in their storm cost recovery reserve balances and may experience such balances and deficits in the future. While the traditional operating companies are generally authorized to recover underrecovered fuel costs through fuel cost recovery clauses and storm recovery costs through special rate provisions administered by the respective PSCs, recovery may be denied if costs are deemed to be imprudently incurred, and delays in the authorization of such recovery could negatively impact the cash flows of the affected traditional operating company and Southern Company.

Southern Company, the traditional operating companies, and Southern Power are subject to risks associated with a changing economic environment as well as the financial stability of the customers of the traditional operating companies and Southern Power.

Southern Company, the traditional operating companies, and Southern Power are exposed to risks related to general economic conditions in their applicable service territory and are thus impacted by the economic cycles of the customers each serves. Any economic downturn or disruption of financial markets, both nationally and internationally, could negatively affect the financial stability of the customers and counterparties of the traditional operating companies and Southern Power. As territories served by the traditional operating companies and Southern Power experience economic downturns, energy consumption patterns may change and revenues may be negatively impacted. Customer growth and customer usage can be affected by economic factors in the service territory of the traditional operating companies and Southern Power and elsewhere, including, for example, job and income growth, housing starts, new home prices, and the economic impact on customers of federal fiscal decisions. Adverse economic conditions, a population decline, and/or business closings in the territory served by the traditional operating companies or Southern Power or slower than anticipated customer growth as a result of a recessionary economy or otherwise could also have a negative impact on revenues and could result in greater expense for uncollectible customer balances. As with other parts of the country, the territories served by the traditional operating companies and Southern Power have been impacted by the recent economic recession. The traditional operating companies have experienced residential and commercial sales that continue to be below historical trends due to the recent economic recession. Southern Power is expected to continue to experience reduced future revenues for its requirements customers due to the recent economic recession. The timing and extent of the recovery cannot be predicted.

Stronger or more rapid than expected economic growth, coupled with the effects of current and future environmental regulations applicable to the traditional operating companies or Southern Power, could impact the ability of the traditional operating companies and/or Southern Power to meet the energy demands of their customers. Weaker or slower than expected economic growth could have a negative impact on revenues, could result in greater expense for uncollected customer balances, and could adversely impact the value of generation assets of the traditional operating companies and/or Southern Power.

All of the factors discussed above could adversely affect Southern Company's, the traditional operating companies', and/or Southern Power's level of future net income.

The operating results of Southern Company, the traditional operating companies, and Southern Power are affected by weather conditions and may fluctuate on a seasonal and quarterly basis. In addition, significant weather events, such as

hurricanes, tornadoes, floods, and droughts could result in substantial damage to or limit the operation of the properties of the traditional operating companies and/or Southern Power and could negatively impact results of operation, financial condition, and liquidity.

Electric power supply is generally a seasonal business. In many parts of the country, demand for power peaks during the summer months, with market prices also peaking at that time. In other areas, power demand peaks during the winter. As a result, the overall operating results of Southern Company, the traditional operating companies, and Southern Power may fluctuate substantially on a seasonal basis. In addition, the traditional operating companies and Southern Power have historically sold less power when weather conditions are milder. Unusually mild weather in the future could reduce the revenues, net income, available cash, and borrowing ability of Southern Company, the traditional operating companies, and/or Southern Power.

In addition, volatile or significant weather events could result in substantial damage to the transmission and distribution lines of the traditional operating companies and the generating facilities of the traditional operating companies and Southern Power. The traditional operating companies and Southern Power have significant investments in the Atlantic and Gulf Coast regions which could be subject to major storm activity. Further, severe drought conditions can reduce the availability of water and restrict or prevent the operation of certain generating facilities.

Each traditional operating company maintains a reserve for property damage to cover the cost of damages from weather events to its transmission and distribution lines and the cost of uninsured damages to its generating facilities and other property. In the event a traditional operating company experiences any of these weather events or any natural disaster or other catastrophic event, recovery of costs in excess of reserves and insurance coverage is subject to the approval of its state PSC. While the traditional operating companies generally are entitled to recover prudently-incurred costs incurred in connection with such an event, any denial by the applicable state PSC or delay in recovery of any portion of such costs could have a material negative impact on a traditional operating company's and Southern Company's results of operations, financial condition, and liquidity.

In addition, damages resulting from significant weather events within the service territory of any traditional operating company or affecting Southern Power's customers may result in the loss of customers and reduced demand for electricity for extended periods. Any significant loss of customers or reduction in demand for electricity could have a material negative impact on a traditional operating company's or Southern Power's and Southern Company's results of operations, financial condition, and liquidity.

Southern Company may be unable to meet its ongoing and future financial obligations and to pay dividends on its common stock if its subsidiaries are unable to pay upstream dividends or repay funds to Southern Company.

Southern Company is a holding company and, as such, Southern Company has no operations of its own. Substantially all of Southern Company's consolidated assets are held by subsidiaries. Southern Company's ability to meet its financial obligations and to pay dividends on its common stock is primarily dependent on the net income and cash flows of its subsidiaries and their ability to pay upstream dividends or to repay funds to Southern Company. Prior to funding Southern Company, Southern Company's subsidiaries have regulatory restrictions and financial obligations that must be satisfied, including among others, debt service and preferred and preference stock dividends. Southern Company's subsidiaries are separate legal entities and have no obligation to provide Southern Company with funds.

A downgrade in the credit ratings of Southern Company, the traditional operating companies, or Southern Power could negatively affect their ability to access capital at reasonable costs and/or could require Southern Company, the traditional operating companies, or Southern Power to post collateral or replace certain indebtedness.

There are a number of factors that rating agencies evaluate to arrive at credit ratings for Southern Company, the traditional operating companies, and Southern Power, including capital structure, regulatory environment, the ability to cover liquidity requirements, and other commitments for capital. Southern Company, the traditional operating companies, and Southern Power could experience a downgrade in their ratings if any rating agency concludes that the level of business or financial risk of the industry or Southern Company, the traditional operating companies, or Southern Power has deteriorated. Changes in ratings methodologies by the agencies could also have a negative impact on credit ratings. If one or more rating agencies downgrade Southern Company, the traditional operating companies, or Southern Power, borrowing costs would increase, the pool of investors and funding sources would likely decrease, and, particularly for any downgrade to below investment grade, significant collateral requirements may be triggered in a number of contracts.

The use of derivative contracts by Southern Company and its subsidiaries in the normal course of business could result in financial losses that negatively impact the net income of Southern Company and its subsidiaries.

Southern Company and its subsidiaries, including the traditional operating companies and Southern Power, use derivative instruments, such as swaps, options, futures, and forwards, to manage their commodity and interest rate exposures and, to a lesser extent, engage in limited trading activities. Southern Company and its subsidiaries could recognize financial losses as a result of volatility in the market values of these contracts or if a counterparty fails to perform. These risks are managed through risk management policies, limits, and procedures. These risk management policies, limits, and procedures might not work as planned and cannot entirely eliminate the risks associated with these activities. In addition, derivative contracts entered for hedging purposes might not off-set the underlying exposure being hedged as expected, resulting in financial losses. In the absence of actively quoted market prices and pricing information from external sources, the valuation of these financial instruments can involve management's judgment or use of estimates. The factors used in the valuation of these instruments become more difficult to predict and the calculations become less reliable the further into the future these estimates are made. As a result, changes in the underlying assumptions or use of alternative valuation methods could affect the value of the reported fair value of these contracts.

Demand for power could decrease or fail to grow at expected rates, resulting in stagnant or reduced revenues, limited growth opportunities, and potentially stranded generation assets.

Southern Company, the traditional operating companies, and Southern Power each engage in a long-term planning process to determine the optimal mix and timing of new generation assets required to serve future load obligations. This planning process must look many years into the future in order to accommodate the long lead times associated with the permitting and construction of new generation facilities. Inherent risk exists in predicting demand this far into the future as these future loads are dependent on many uncertain factors, including regional economic conditions, customer usage patterns, efficiency programs, and customer technology adoption. Because regulators may not permit the traditional operating companies to adjust rates to recover the costs of new generation assets while such assets are being constructed, the traditional operating companies may not be able to fully recover these costs or may have exposure to regulatory lag associated with the time between the incurrence of costs of additional capacity and the traditional operating companies' recovery in customers' rates. Under Southern Power's model of selling capacity and energy at negotiated market-based rates under long-term PPAs, Southern Power might not be able to fully execute its business plan if market prices drop below original forecasts. Southern Power may not be able to extend its existing PPAs or to find new buyers for existing generation assets as existing PPAs expire, or it may be forced to market these assets at prices lower than originally intended. These situations could have negative impacts on net income and cash flows for the affected traditional operating company or Southern Power and for Southern Company.

Demand for power could exceed supply capacity, resulting in increased costs for purchasing capacity in the open market or building additional generation facilities.

The traditional operating companies and Southern Power are currently obligated to supply power to retail customers and wholesale customers under long-term PPAs. At peak times, the demand for power required to meet this obligation could exceed the Southern Company system's available generation capacity. Market or competitive forces may require that the traditional operating companies or Southern Power purchase capacity on the open market or build additional generation facilities. Because regulators may not permit the traditional operating companies to pass all of these purchase or construction costs on to their customers, the traditional operating companies may not be able to recover any of these costs or may have exposure to regulatory lag associated with the time between the incurrence of costs of purchased or constructed capacity and the traditional operating companies' recovery in customers' rates. Under Southern Power's long-term fixed price PPAs, Southern Power would not have the ability to recover any of these costs. These situations could have negative impacts on net income and cash flows for the affected traditional operating company or Southern Power and for Southern Company.

Energy conservation and energy price increases could negatively impact financial results.

Customers could voluntarily reduce their consumption of electricity in response to decreases in their disposable income, increases in energy price, or individual conservation efforts. In addition, a number of regulatory and legislative bodies have proposed or introduced requirements and/or incentives to reduce energy consumption by certain dates. Conservation programs could impact the financial results of Southern Company, the traditional operating companies, and Southern Power in different ways. For example, if any traditional operating company is required to invest in conservation measures that result in reduced sales from effective conservation, regulatory lag in adjusting rates for the impact of these measures could have a negative financial impact on such traditional operating company and Southern Company.

Certain of the traditional operating companies actively promote energy conservation programs, which have been approved by their respective state PSCs. Regulatory mechanisms have been established that provide for the recovery of costs related to such programs and lost revenues as a result of such programs. However, to the extent conservation results in reduced energy demand or significantly slows the growth in demand beyond what is anticipated, the value of generation assets of the traditional operating companies and/or Southern Power and other unregulated business activities could be adversely impacted and the traditional operating companies could be negatively impacted depending on the regulatory treatment of the associated impacts. In addition, the failure of those traditional operating companies who actively promote energy conservation programs to achieve the energy conservation targets established by their respective state PSCs could negatively impact such traditional operating company's ability to recover costs and receive certain benefits related to such programs.

Additionally, Southern Company, the traditional operating companies, and Southern Power could also be negatively impacted if any future energy price increases result in a decrease in customer usage.

Southern Company, the traditional operating companies, and Southern Power are unable to determine what impact, if any, conservation and increases in energy prices will have on their respective financial condition or results of operations.

The businesses of Southern Company, the traditional operating companies, and Southern Power are dependent on their ability to successfully access funds through capital markets and financial institutions. The inability of Southern Company, any traditional operating company, or Southern Power to access funds may limit its ability to execute its business plan by impacting its ability to fund capital investments or acquisitions that Southern Company, the traditional operating companies, or Southern Power may otherwise rely on to achieve future earnings and cash flows.

Southern Company, the traditional operating companies, and Southern Power rely on access to both short-term money markets and longer-term capital markets as a significant source of liquidity for capital requirements not satisfied by the cash flow from their respective operations. If Southern Company, any traditional operating company, or Southern Power is not able to access capital at competitive rates, its ability to implement its business plan will be limited by impacting its ability to fund capital investments or acquisitions that Southern Company, the traditional operating companies, or Southern Power may otherwise rely on to achieve future earnings and cash flows. In addition, Southern Company, the traditional operating companies, and Southern Power rely on committed bank lending agreements as back-up liquidity which allows them to access low cost money markets. Each of Southern Company, the traditional operating companies, and Southern Power believes that it will maintain sufficient access to these financial markets based upon current credit ratings. However, certain events or market disruptions may increase the cost of borrowing or adversely affect the ability to raise capital through the issuance of securities or other borrowing arrangements or the ability to secure committed bank lending agreements used as back-up sources of capital. Such disruptions could include:

- an economic downturn or uncertainty;
- bankruptcy or financial distress at an unrelated energy company, financial institution, or sovereign entity;
- capital markets volatility and disruption, either nationally or internationally;
- changes in tax policy such as dividend tax rates;
- market prices for electricity and gas;
- terrorist attacks or threatened attacks on Southern Company's facilities or unrelated energy companies' facilities;
- war or threat of war; or
- the overall health of the utility and financial institution industries.

Market performance and other changes may decrease the value of benefit plans and nuclear decommissioning trust assets or may increase plan costs, which then could require significant additional funding.

The performance of the capital markets affects the values of the assets held in trust under Southern Company's pension and postretirement benefit plans and the assets held in trust to satisfy obligations to decommission Alabama Power's and Georgia

Power's nuclear plants. The Southern Company system has significant obligations related to pension and postretirement benefit plans. Alabama Power and Georgia Power each hold significant assets in the nuclear decommissioning trusts. These assets are subject to market fluctuations and will yield uncertain returns, which may fall below projected return rates. A decline in the market value of these assets, as has been experienced in prior periods, may increase the funding requirements relating to benefit plan liabilities of the Southern Company system and Alabama Power's and Georgia Power's nuclear decommissioning obligations. Additionally, changes in interest rates affect the liabilities under pension and postretirement benefit plans of the Southern Company system; as interest rates decrease, the liabilities increase, potentially requiring additional funding. Further, changes in demographics, including an increased number of retirements or changes in life expectancy assumptions, may also increase the funding requirements of the obligations related to the pension benefit plans. Southern Company and its subsidiaries are also facing rising medical benefit costs, including the current costs for active and retired employees. It is possible that these costs may increase at a rate that is significantly higher than anticipated. If the Southern Company system is unable to successfully manage benefit plan assets and medical benefit costs and Alabama Power and Georgia Power are unable to successfully manage the nuclear decommissioning trust funds, results of operations and financial position could be negatively affected.

Southern Company may be unable to recover its investment in its leveraged leases if a lessee fails to profitably operate the leased assets.

Southern Company has several leveraged lease agreements, with terms ranging up to 45 years, which relate to international and domestic energy generation, distribution, and transportation assets. Southern Company receives federal income tax deductions for depreciation and amortization, as well as interest on long-term debt related to these investments. Southern Company reviews all important lease assumptions at least annually, or more frequently if events or changes in circumstances indicate that a change in assumptions has occurred or may occur. With respect to Southern Company's investments in leveraged leases, the recovery of its investment is dependent on the profitable operation of the leased assets by the respective lessees. A significant deterioration in the performance of the leased asset could result in the impairment of the related lease receivable.

Southern Company, the traditional operating companies, and Southern Power are subject to risks associated with their ability to obtain adequate insurance.

The financial condition of some insurance companies, the threat of terrorism, and natural disasters, among other things, could have disruptive effects on insurance markets. The availability of insurance covering risks that Southern Company, the traditional operating companies, Southern Power, and their respective competitors typically insure against may decrease, and the insurance that Southern Company, the traditional operating companies, and Southern Power are able to obtain may have higher deductibles, higher premiums, and more restrictive policy terms. Further, while Southern Company, the traditional operating companies, and Southern Power maintain an amount of insurance protection that they consider adequate, there is no guarantee that the insurance policies selected by them will cover all of the potential exposures or the actual amount of loss incurred.

Any losses not covered by insurance could adversely affect the results of operations, cash flows, or financial condition of Southern Company, the traditional operating companies, or Southern Power.

Item 1B. UNRESOLVED STAFF COMMENTS.

None.

Item 2. PROPERTIES

Electric Properties

The traditional operating companies, Southern Power, and SEGCO, at December 31, 2012, owned and/or operated 33 hydroelectric generating stations, 32 fossil fuel generating stations, three nuclear generating stations, and 13 combined cycle/ cogeneration stations, four solar facilities, one landfill gas facility, and one biomass facility. The amounts of capacity for each company are shown in the table below.

Generating Station	Location	Nameplate Capacity (1)	
		(KWs)	
FOSSIL STEAM			
Gadsden	Gadsden, AL	120,000	
Gorgas	Jasper, AL	1,221,250	
Barry	Mobile, AL	1,525,000	
Greene County	Demopolis, AL	300,000	(2)
Gaston Unit 5	Wilsonville, AL	880,000	
Miller	Birmingham, AL	2,532,288	(3)
Alabama Power Total		6,578,538	
Bowen	Cartersville, GA	3,160,000	
Branch	Milledgeville, GA	1,539,700	(4)
Hammond	Rome, GA	800,000	
Kraft	Port Wentworth, GA	281,136	(4)
McIntosh	Effingham County, GA	163,117	
McManus	Brunswick, GA	115,000	(4)
Mitchell	Albany, GA	125,000	
Scherer	Macon, GA	750,924	(5)
Wansley	Carrollton, GA	925,550	(6)
Yates	Newnan, GA	1,250,000	(4)
Georgia Power Total		9,110,427	
Crist	Pensacola, FL	970,000	
Daniel	Pascagoula, MS	500,000	(7)
Lansing Smith	Panama City, FL	305,000	
Scholz	Chattahoochee, FL	80,000	
Scherer Unit 3	Macon, GA	204,500	(5)
Gulf Power Total		2,059,500	
Daniel	Pascagoula, MS	500,000	(7)
Greene County	Demopolis, AL	200,000	(2)
Sweatt	Meridian, MS	80,000	
Watson	Gulfport, MS	1,012,000	
Mississippi Power Total		1,792,000	(8)
Gaston Units 1-4	Wilsonville, AL		
SEGCO Total		1,000,000	(9)
Total Fossil Steam		20,540,465	

Generating Station	Location	Nameplate Capacity (1)	
NUCLEAR STEAM			
Farley	Dothan, AL		
Alabama Power Total		1,720,000	
Hatch	Baxley, GA	899,612	(10)
Vogtle	Augusta, GA	1,060,240	(11)
Georgia Power Total		1,959,852	
Total Nuclear Steam		3,679,852	
COMBUSTION TURBINES			
Greene County	Demopolis, AL		
Alabama Power Total		720,000	
Boulevard	Savannah, GA	59,100	(4)
Bowen	Cartersville, GA	39,400	(4)
Intercession City	Intercession City, FL	47,667	(12)
Kraft	Port Wentworth, GA	22,000	
McDonough Unit 3	Atlanta, GA	78,800	
McIntosh Units 1 through 8	Effingham County, GA	640,000	
McManus	Brunswick, GA	481,700	
Mitchell	Albany, GA	78,800	(13)
Robins	Warner Robins, GA	158,400	
Wansley	Carrollton, GA	26,322	(6)
Wilson	Augusta, GA	354,100	
Georgia Power Total		1,986,289	
Lansing Smith Unit A	Panama City, FL	39,400	
Pea Ridge Units 1 through 3	Pea Ridge, FL	15,000	
Gulf Power Total		54,400	
Chevron Cogenerating Station	Pascagoula, MS	147,292	(14)
Sweatt	Meridian, MS	39,400	
Watson	Gulfport, MS	39,360	
Mississippi Power Total		226,052	
Cleveland County	Cleveland County, NC	720,000	
Dahlberg	Jackson County, GA	756,000	
Oleander	Cocoa, FL	791,301	
Rowan	Salisbury, NC	455,250	
West Georgia	Thomaston, GA	668,800	
Southern Power Total		3,391,351	
Gaston **(SEGCO)**	Wilsonville, AL	19,680	(9)
Total Combustion Turbines		6,397,772	
COGENERATION			
Washington County	Washington County, AL	123,428	
GE Plastics Project	Burkeville, AL	104,800	
Theodore	Theodore, AL	236,418	
Total Cogeneration		464,646	

Generating Station	Location	Nameplate Capacity (1)	
COMBINED CYCLE			
Barry	Mobile, AL		
Alabama Power Total		1,070,424	
McIntosh Units 10&11	Effingham County, GA	1,318,920	
McDonough-Atkinson Units 4 through 6	Atlanta, GA	2,520,000	(15)
Georgia Power Total		3,838,920	
Smith	Lynn Haven, FL		
Gulf Power Total		545,500	
Daniel	Pascagoula, MS		
Mississippi Power Total		1,070,424	
Franklin	Smiths, AL	1,857,820	
Harris	Autaugaville, AL	1,318,920	
Rowan	Salisbury, NC	530,550	
Stanton Unit A	Orlando, FL	428,649	(16)
Wansley	Carrollton, GA	1,073,000	
Southern Power Total		5,208,939	
Total Combined Cycle		11,734,207	
HYDROELECTRIC FACILITIES			
Bankhead	Holt, AL	53,985	
Bouldin	Wetumpka, AL	225,000	
Harris	Wedowee, AL	132,000	
Henry	Ohatchee, AL	72,900	
Holt	Holt, AL	46,944	
Jordan	Wetumpka, AL	100,000	
Lay	Clanton, AL	177,000	
Lewis Smith	Jasper, AL	157,500	
Logan Martin	Vincent, AL	135,000	
Martin	Dadeville, AL	182,000	
Mitchell	Verbena, AL	170,000	
Thurlow	Tallassee, AL	81,000	
Weiss	Leesburg, AL	87,750	
Yates	Tallassee, AL	47,000	
Alabama Power Total		1,668,079	
Bartletts Ferry	Columbus, GA	173,000	
Goat Rock	Columbus, GA	38,600	
Lloyd Shoals	Jackson, GA	14,400	
Morgan Falls	Atlanta, GA	16,800	
North Highlands	Columbus, GA	29,600	
Oliver Dam	Columbus, GA	60,000	
Rocky Mountain	Rome, GA	215,256	(17)
Sinclair Dam	Milledgeville, GA	45,000	
Tallulah Falls	Clayton, GA	72,000	
Terrora	Clayton, GA	16,000	
Tugalo	Clayton, GA	45,000	

Generating Station	Location	Nameplate Capacity (1)	
Wallace Dam	Eatonton, GA	321,300	
Yonah	Toccoa, GA	22,500	
6 Other Plants	Various Georgia Cities	18,080	
Georgia Power Total		1,087,536	
Total Hydroelectric Facilities		2,755,615	
RENEWABLE SOURCES:			
SOLAR FACILITIES			
Dalton	Dalton, GA		
Georgia Power Total		705	
Apex	North Las Vegas, NV	18,000	
Cimarron	Springer, NM	27,576	
Granville	Oxford, NC	2,250	
Southern Power Total		47,826	(18)
Total Solar		48,531	
LANDFILL GAS FACILITY			
Perdido	Escambia County, FL		
Gulf Power Total		3,200	
BIOMASS FACILITY			
Nacogdoches	Sacul, Texas		
Southern Power Total		115,500	
Total Generating Capacity		45,739,788	

Notes:

(1) See "Jointly-Owned Facilities" herein for additional information.

(2) Owned by Alabama Power and Mississippi Power as tenants in common in the proportions of 60% and 40%, respectively.

(3) Capacity shown is Alabama Power's portion (91.84%) of total plant capacity.

(4) Plant Branch Units 1 and 2 are scheduled to be retired on December 31, 2013 and October 1, 2013, respectively. Georgia Power's 2013 IRP filing included Georgia Power's request to decertify 16 coal- and oil-fired units totaling 2,093 MWs. Georgia Power requested the decertification of Plant Boulevard Units 2 and 3 (28 MWs) upon approval of the 2013 IRP and the decertification of Plant Bowen Unit 6 (32 MWs) by April 16, 2013. Plant Branch Units 3 and 4 (1,016 MWs), Plant Yates Units 1 through 5 (579 MWs), and Plant McManus Units 1 and 2 (122 MWs) will be retired by April 16, 2015, the compliance date for the MATS rule. Georgia Power has also requested a revision to the decertification date of Plant Branch Unit 1 from December 31, 2013 to April 16, 2015. To allow for necessary transmission and reliability improvements, Georgia Power expects to seek a one-year extension of the MATS rule compliance date for Plant Kraft Units 1 through 4 (316 MWs) and to retire these units by April 16, 2016.

(5) Capacity shown for Georgia Power is 8.4% of Units 1 and 2 and 75% of Unit 3. Capacity shown for Gulf Power is 25% of Unit 3.

(6) Capacity shown is Georgia Power's portion (53.5%) of total plant capacity.

(7) Represents 50% of the plant which is owned as tenants in common by Gulf Power and Mississippi Power.

(8) Does not include nameplate capacity at Plant Eaton (67,500 KWs), which was retired on December 31, 2012.

(9) SEGCO is jointly-owned by Alabama Power and Georgia Power. See BUSINESS in Item 1 herein for additional information.

(10) Capacity shown is Georgia Power's portion (50.1%) of total plant capacity.

(11) Capacity shown is Georgia Power's portion (45.7%) of total plant capacity.

(12) Capacity shown represents 33 1/3% of total plant capacity. Georgia Power owns a 1/3 interest in the unit with 100% use of the unit from June through September. Progress Energy Florida operates the unit.

(13) Mitchell Unit 4C (39,400 KWs) was retired on March 26, 2012.

(14) Generation is dedicated to a single industrial customer.

(15) McDonough Unit 1 (245,000 KWs) was retired on February 29, 2012. McDonough-Atkinson Units 5 and 6 (1,680,000 KWs) were placed into service on April 26, 2012 and October 28, 2012, respectively.

(16) Capacity shown is Southern Power's portion (65%) of total plant capacity.

(17) Capacity shown is Georgia Power's portion (25.4%) of total plant capacity. OPC operates the plant.

(18) Capacity shown is Southern Power's portion (90%) of the total plant capacity.

Except as discussed below under "Titles to Property," the principal plants and other important units of the traditional operating companies, Southern Power, and SEGCO are owned in fee by the respective companies. It is the opinion of management of each such company that its operating properties are adequately maintained and are substantially in good operating condition.

Mississippi Power owns a 79-mile length of 500-kilovolt transmission line which is leased to Entergy Gulf States Louisiana, LLC. The line, completed in 1984, extends from Plant Daniel to the Louisiana state line. Entergy Gulf States Louisiana, LLC is paying a use fee over a 40-year period covering all expenses and the amortization of the original $57 million cost of the line. At December 31, 2012, the unamortized portion of this cost was approximately $16.8 million.

In conjunction with the Kemper IGCC, Mississippi Power will own a lignite mine and equipment and has acquired and will continue to acquire mineral reserves located around the Kemper IGCC site in Kemper County. The mine is scheduled to be placed in service in June 2013. The estimated capital cost of the mine is approximately $245 million, of which $163.3 million has been incurred through December 31, 2012. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Integrated Coal Gasification Combined Cycle – Lignite Mine and CO_2 Pipeline Facilities" of Mississippi Power in Item 7 herein and Note 3 to the financial statements of Southern Company and Mississippi Power under "Integrated Coal Gasification Combined Cycle – Lignite Mine and CO_2 Pipeline Facilities" in Item 8 herein for additional information on the lignite mine.

In 2012, the maximum demand on the traditional operating companies, Southern Power, and SEGCO was 35,479,000 KWs and occurred on June 29, 2012. The all-time maximum demand of 38,777,000 KWs on the traditional operating companies, Southern Power, and SEGCO occurred on August 22, 2007. These amounts exclude demand served by capacity retained by MEAG Power, OPC, and SEPA. The reserve margin for the traditional operating companies, Southern Power, and SEGCO in

2012 was 20.8%. See SELECTED FINANCIAL DATA in Item 6 herein for additional information on peak demands for each registrant.

Jointly-Owned Facilities

Alabama Power, Georgia Power, and Southern Power have undivided interests in certain generating plants and other related facilities to or from non-affiliated parties. The percentages of ownership are as follows:

		Percentage Ownership										
	Total Capacity	Alabama Power	Power South	Georgia Power	OPC	MEAG Power	Dalton	Progress Energy Florida	Southern Power	OUC	FMPA	KUA
	(MWs)											
Plant Miller Units 1 and 2	1,320	91.8%	8.2%	—%	—%	—%	—%	—%	—%	—%	—%	—%
Plant Hatch	1,796	—	—	50.1	30.0	17.7	2.2	—	—	—	—	—
Plant Vogtle Units 1 and 2	2,320	—	—	45.7	30.0	22.7	1.6	—	—	—	—	—
Plant Scherer Units 1 and 2	1,636	—	—	8.4	60.0	30.2	1.4	—	—	—	—	—
Plant Wansley	1,779	—	—	53.5	30.0	15.1	1.4	—	—	—	—	—
Rocky Mountain	848	—	—	25.4	74.6	—	—	—	—	—	—	—
Intercession City, FL	143	—	—	33.3	—	—	—	66.7	—	—	—	—
Plant Stanton A	660	—	—	—	—	—	—	—	65%	28%	3.5%	3.5%

Alabama Power and Georgia Power have contracted to operate and maintain the respective units in which each has an interest (other than Rocky Mountain and Intercession City) as agent for the joint owners. SCS provides operation and maintenance services for Plant Stanton A.

In addition, Georgia Power has commitments regarding a portion of a 5% interest in Plant Vogtle Units 1 and 2 owned by MEAG Power that are in effect until the later of retirement of the plant or the latest stated maturity date of MEAG Power's bonds issued to finance such ownership interest. The payments for capacity are required whether any capacity is available. The energy cost is a function of each unit's variable operating costs. Except for the portion of the capacity payments related to the Georgia PSC's disallowances of Plant Vogtle Units 1 and 2 costs, the cost of such capacity and energy is included in purchased power from non-affiliates in Georgia Power's statements of income in Item 8 herein. Also see Note 7 to the financial statements of Georgia Power under "Commitments — Purchased Power Commitments" in Item 8 herein for additional information.

Titles to Property

The traditional operating companies', Southern Power's, and SEGCO's interests in the principal plants (other than certain pollution control facilities and the land on which five combustion turbine generators of Mississippi Power are located, which is held by easement) and other important units of the respective companies are owned in fee by such companies, subject only to the liens pursuant to pollution control revenue bonds of Alabama Power and Gulf Power on specific pollution control facilities and liens pursuant to the assumption of debt obligations by Mississippi Power in connection with the acquisition of Plant Daniel Units 3 and 4. See Note 6 to the financial statements of Southern Company, Alabama Power, Gulf Power, and Mississippi Power under "Assets Subject to Lien" in Item 8 herein for additional information. The traditional operating companies own the fee interests in certain of their principal plants as tenants in common. See "Jointly-Owned Facilities" herein for additional information. Properties such as electric transmission and distribution lines and steam heating mains are constructed principally on rights-of-way which are maintained under franchise or are held by easement only. A substantial portion of lands submerged by reservoirs is held under flood right easements.

Item 3. LEGAL PROCEEDINGS

(1) United States of America v. Alabama Power (United States District Court for the Northern District of Alabama)

United States of America v. Georgia Power (United States District Court for the Northern District of Georgia)

See Note 3 to the financial statements of Southern Company and each traditional operating company under "Environmental Matters – New Source Review Actions" in Item 8 herein for information.

(2) Native Village of Kivalina and the City of Kivalina v. Exxon Mobile et al. (United States District Court for the Northern District of California)

See Note 3 to the financial statements of Southern Company, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, and Southern Power under "Climate Change Litigation – Kivalina Case" in Item 8 herein for information.

(3) Comer et al. v. Murphy Oil USA, Inc. (United States District Court for the Southern District of Mississippi)

See Note 3 to the financial statements of Southern Company, Alabama Power, Georgia Power, Gulf Power, and Southern Power under "Climate Change Litigation – Hurricane Katrina Case" in Item 8 herein for information.

(4) Georgia Power et al. v. Westinghouse and Stone & Webster (United States District Court for the Southern District of Georgia Augusta Division)

Stone & Webster and Westinghouse v. Georgia Power et al. (United States District Court for the District of Columbia)

See Note 3 to the financial statements of Georgia Power under "Retail Regulatory Matters – Nuclear Construction" in Item 8 herein for information.

(5) Environmental Remediation

See Note 3 to the financial statements of Southern Company, Georgia Power, Gulf Power, and Mississippi Power under "Environmental Matters – Environmental Remediation" in Item 8 herein for information related to environmental remediation.

See Note 3 to the financial statements of each registrant in Item 8 herein for descriptions of additional legal and administrative proceedings discussed therein.

Item 4. MINE SAFETY DISCLOSURES

Not applicable.

EXECUTIVE OFFICERS OF SOUTHERN COMPANY

(Identification of executive officers of Southern Company is inserted in Part I in accordance with Regulation S-K, Item 401(b), Instruction 3.) The ages of the officers set forth below are as of December 31, 2012.

Thomas A. Fanning
Chairman, President, Chief Executive Officer, and Director
Age 55
Elected in 2003. Chairman and Chief Executive Officer since December 2010 and President since August 2010. Previously served as Executive Vice President and Chief Operating Officer from February 2008 through July 2010. He also served as Executive Vice President and Chief Financial Officer from May 2007 through January 2008.

Art P. Beattie
Executive Vice President and Chief Financial Officer
Age 58
Elected in 2010. Executive Vice President and Chief Financial Officer since August 2010. Previously served as Executive Vice President, Chief Financial Officer, and Treasurer of Alabama Power from February 2005 through August 2010.

W. Paul Bowers
Executive Vice President
Age 56
Elected in 2001. Executive Vice President since February 2008 and Chief Executive Officer, President, and Director of Georgia Power since January 2011 and Chief Operating Officer of Georgia Power from August 2010 to December 2010. He previously served as Executive Vice President and Chief Financial Officer of Southern Company from February 2008 to August 2010.

S. W. Connally, Jr.
President and Chief Executive Officer of Gulf Power
Age 43
Elected in 2012. President, Chief Executive Officer, and Director of Gulf Power since July 1, 2012. Previously served as Senior Vice President and Chief Production Officer of Georgia Power from August 2010 through June 2012 and Manager of Alabama Power's Plant Barry from August 2007 through July 2010.

Mark A. Crosswhite
Executive Vice President and Chief Operating Officer
Age 50
Elected in 2010. Executive Vice President and Chief Operating Officer since July 1, 2012. Previously served as President, Chief Executive Officer, and Director of Gulf Power from January 2011 through June 2012, Executive Vice President of External Affairs at Alabama Power from February 2008 through December 2010, and Senior Vice President and Counsel of Alabama Power from July 2006 through January 2008.

Edward Day, VI
President and Chief Executive Officer of Mississippi Power
Age 52
Elected in 2010. President, Chief Executive Officer, and Director of Mississippi Power since August 2010. Previously served as Executive Vice President for Engineering and Construction Services at Southern Company Generation, a business unit of Southern Company, from May 2003 to August 2010.

G. Edison Holland, Jr.
Executive Vice President, General Counsel, and Corporate Secretary
Age 60
Elected in 2001. Corporate Secretary since April 2005 and Executive Vice President and General Counsel since April 2001.

Stephen E. Kuczynski
President and Chief Executive Officer of Southern Nuclear
Age 50
Elected in 2011. President and Chief Executive Officer of Southern Nuclear since July 2011. Before joining Southern Company, Mr. Kuczynski served at Exelon Corporation as the Senior Vice President of Engineering and Technical Services for Exelon Nuclear from February 2006 to June 2011.

Charles D. McCrary
Executive Vice President
Age 61
Elected in 1998. Executive Vice President since February 2002 and President, Chief Executive Officer, and Director of Alabama Power since October 2001.

Susan N. Story
Executive Vice President (to retire effective April 1, 2013)
Age 52
Elected in 2003. President and Chief Executive Officer of SCS since January 2011. Previously served as President, Chief Executive Officer, and Director of Gulf Power from April 2003 through December 2010.

Christopher C. Womack
Executive Vice President
Age 54
Elected in 2008. Executive Vice President and President of External Affairs since January 2009. Previously served as Executive Vice President of External Affairs of Georgia Power from March 2006 through December 2008.

The officers of Southern Company were elected for a term running from the first meeting of the directors following the last annual meeting (May 23, 2012) for one year or until their successors are elected and have qualified, except for Mr. Crosswhite whose election was effective July 1, 2012.

EXECUTIVE OFFICERS OF ALABAMA POWER

(Identification of executive officers of Alabama Power is inserted in Part I in accordance with Regulation S-K, Item 401(b), Instruction 3.) The ages of the officers set forth below are as of December 31, 2012.

Charles D. McCrary
President, Chief Executive Officer, and Director
Age 61
Elected in 2001. President, Chief Executive Officer, and Director since October 2001. Since February 2002, he has also served as Executive Vice President of Southern Company.

Philip C. Raymond
Executive Vice President, Chief Financial Officer, and Treasurer
Age 53
Elected in 2010. Executive Vice President, Chief Financial Officer, and Treasurer since August 2010. Previously served as Vice President and Chief Financial Officer of Gulf Power from May 2008 to August 2010 and as Vice President and Comptroller of Alabama Power from January 2005 to April 2008.

Zeke W. Smith
Executive Vice President
Age 53
Elected in 2010. Executive Vice President of External Affairs since November 2010. Previously served as Vice President of Regulatory Services and Financial Planning from February 2005 to November 2010.

Steven R. Spencer
Executive Vice President
Age 57
Elected in 2001. Executive Vice President of the Customer Service Organization since February 2008. Previously served as Executive Vice President of External Affairs from 2001 through January 2008.

Theodore J. McCullough
Senior Vice President and Senior Production Officer
Age 49
Elected in 2010. Senior Vice President and Senior Production Officer since June 2010. Previously served as Vice President and Senior Production Officer of Gulf Power from September 2007 until June 2010.

The officers of Alabama Power were elected for a term running from the meeting of the directors held on April 27, 2012 for one year or until their successors are elected and have qualified.

EXECUTIVE OFFICERS OF GEORGIA POWER

(Identification of executive officers of Georgia Power is inserted in Part I in accordance with Regulation S-K, Item 401(b), Instruction 3.) The ages of the officers set forth below are as of December 31, 2012.

W. Paul Bowers
President, Chief Executive Officer, and Director
Age 56
Elected in 2010. Chief Executive Officer, President, and Director since December 2010 and Chief Operating Officer of Georgia Power from August 2010 to December 2010. He previously served as Executive Vice President and Chief Financial Officer of Southern Company from February 2008 to August 2010. He also served as Executive Vice President of Southern Company from May 2007 to February 2008 and as President of Southern Company Generation, a business unit of Southern Company, and Executive Vice President of SCS from May 2001 through January 2008.

W. Craig Barrs
Executive Vice President
Age 55
Elected in 2008. Executive Vice President of External Affairs since January 2010. Previously served as Senior Vice President of External Affairs from January 2009 to January 2010, Vice President of Governmental and Regulatory Affairs from April 2008 to December 2008, and Vice President of the Coastal Region from August 2006 to March 2008.

Ronnie R. Labrato
Executive Vice President, Chief Financial Officer, and Treasurer (to retire effective March 31, 2013)
Age 59
Elected in 2009. Executive Vice President, Chief Financial Officer, and Treasurer since April 2009. Previously served as Vice President of Internal Auditing at SCS from April 2008 to March 2009 and Vice President and Chief Financial Officer of Gulf Power from July 2001 to March 2008.

Joseph A. Miller
Executive Vice President
Age 51
Elected in 2009. Executive Vice President of Nuclear Development since May 2009. He also has served as Executive Vice President of Nuclear Development at Southern Nuclear since February 2006.

Anthony L. Wilson
Executive Vice President
Age 48
Elected in 2011. Executive Vice President of Customer Service and Operations since January 1, 2012. Previously served as Vice President of Transmission from November 2009 to December 2011 and Vice President of Distribution from February 2007 to November 2009.

Thomas P. Bishop
Senior Vice President, Chief Compliance Officer, General Counsel, and Corporate Secretary
Age 52
Elected in 2008. Corporate Secretary since April 2011 and Senior Vice President, Chief Compliance Officer, and General Counsel since September 2008. Previously served as Vice President and Associate General Counsel for SCS from July 2004 to September 2008.

John L. Pemberton
Senior Vice President and Senior Production Officer
Age 42
Elected in 2012. Senior Vice President and Senior Production Officer since July 1, 2012. Previously served as Senior Vice President and General Counsel for SCS and Southern Nuclear from June 2010 to July 2012 and Vice President of Governmental Affairs for SCS from August 2006 to June 2010.

The officers of Georgia Power were elected for a term running from the meeting of the directors held on May 16, 2012 for one year or until their successors are elected and have qualified, except for Mr. Pemberton, whose election was effective July 1, 2012.

EXECUTIVE OFFICERS OF MISSISSIPPI POWER

(Identification of executive officers of Mississippi Power is inserted in Part I in accordance with Regulation S-K, Item 401(b), Instruction 3.) The ages of the officers set forth below are as of December 31, 2012.

Edward Day, VI
President, Chief Executive Officer, and Director
Age 52
Elected in 2010. President, Chief Executive Officer, and Director since August 2010. Previously served as Executive Vice President for Engineering and Construction Services at Southern Company Generation, a business unit of Southern Company, from May 2003 to August 2010.

Thomas O. Anderson, IV
Vice President
Age 53
Elected in 2009. Vice President of Generation Development since July 2009. Previously served as Project Director, Mississippi Power Generation Development from March 2008 to July 2009; Project Manager, Southern Power Generation from June 2007 to March 2008; and Generation Development Manager, SCS Generation Development from September 1998 to June 2007.

John W. Atherton
Vice President
Age 52
Elected in 2004. Vice President of Corporate Services and Community Relations since October 2012. Previously served as Vice President of External Affairs from January 2005 until October 2012.

Moses H. Feagin
Vice President, Treasurer, and Chief Financial Officer
Age 48
Elected in 2010. Vice President, Treasurer, and Chief Financial Officer since August 2010. Previously served as Vice President and Comptroller of Alabama Power from May 2008 to August 2010, and Comptroller of Mississippi Power from March 2005 to May 2008.

Jeff G. Franklin
Vice President
Age 45
Elected in 2011. Vice President of Customer Services Organization since August 2011. Previously served as Georgia Power's Vice President of Governmental and Legislative Affairs from January 2011 to July 2011, Vice President of Governmental and Regulatory Affairs from March 2009 to January 2011, Vice President of Sales from July 2008 to April 2009, and Vice President of the Northwest region from February 2005 to June 2008.

R. Allen Reaves
Vice President
Age 53

Elected in 2010. Vice President and Senior Production Officer since August 2010. Previously served as Manager of Mississippi Power's Plant Daniel from September 2007 through July 2010 and Site Manager for Southern Power's Plant Franklin from March 2006 to September 2007.

Billy F. Thornton
Vice President
Age 52
Elected in 2012. Vice President of Legislative and Regulatory Affairs since October 22, 2012. Previously served as Director of External Affairs from October 2011 until October 2012, Director of Marketing from March 2011 through October 2011, and Major Account Sales Manager from June 2006 to March 2011.

The officers of Mississippi Power were elected for a term running from the meeting of the directors held on April 24, 2012 for one year or until their successors are elected and have qualified, except for Mr. Thornton, whose election was effective October 22, 2012.

PART II

Item 5. MARKET FOR REGISTRANTS' COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

(a)(1) The common stock of Southern Company is listed and traded on the New York Stock Exchange. The common stock is also traded on regional exchanges across the United States. The high and low stock prices as reported on the New York Stock Exchange for each quarter of the past two years were as follows:

	High	Low
2012		
First Quarter	$ 46.06	$ 43.71
Second Quarter	48.45	44.22
Third Quarter	48.59	44.64
Fourth Quarter	47.09	41.75
2011		
First Quarter	$ 38.79	$ 36.51
Second Quarter	40.87	37.43
Third Quarter	43.09	35.73
Fourth Quarter	46.69	41.00

There is no market for the other registrants' common stock, all of which is owned by Southern Company.

(a)(2) Number of Southern Company's common stockholders of record at January 31, 2013: 149,136

Each of the other registrants have one common stockholder, Southern Company.

(a)(3) Dividends on each registrant's common stock are payable at the discretion of their respective board of directors. The dividends on common stock declared by Southern Company and the traditional operating companies to their stockholder(s) for the past two years were as follows:

Registrant	Quarter	2012	2011
		(in thousands)	
Southern Company	First	$ 410,040	$ 385,010
	Second	426,891	402,165
	Third	429,711	405,879
	Fourth	426,450	408,294
Alabama Power	First	134,763	138,275
	Second	134,762	138,275
	Third	134,763	138,275
	Fourth	279,762	359,275
Georgia Power	First	227,075	224,025
	Second	227,075	224,025
	Third	227,075	224,025
	Fourth	302,075	424,025
Gulf Power	First	28,950	27,500
	Second	28,950	27,500
	Third	28,950	27,500
	Fourth	28,950	27,500
Mississippi Power	First	26,700	18,875
	Second	26,700	18,875
	Third	26,700	18,875
	Fourth	26,700	18,875

In 2012 and 2011, Southern Power paid dividends to Southern Company as follows:

Registrant	Quarter	2012	2011
		(in thousands)	
Southern Power	First	$ 31,750	$ 22,800
	Second	31,750	22,800
	Third	31,750	22,800
	Fourth	31,750	22,800

The dividend paid per share of Southern Company's common stock was 47.25¢ for the first quarter 2012 and 49¢ each for the second, third, and fourth quarters of 2012. In 2011, Southern Company paid a dividend per share of 45.50¢ for the first quarter and 47.25¢ each for the second, third, and fourth quarters.

The traditional operating companies and Southern Power can only pay dividends to Southern Company out of retained earnings or paid-in-capital.

Southern Power's senior note indenture contains potential limitations on the payment of common stock dividends. At December 31, 2012, Southern Power was in compliance with the conditions of this senior note indenture and thus had no restrictions on its ability to pay common stock dividends. See Note 8 to the financial statements of Southern Company under "Common Stock Dividend Restrictions" and Note 6 to the financial statements of Southern Power under "Dividend Restrictions" in Item 8 herein for additional information regarding these restrictions.

(a)(4) Securities authorized for issuance under equity compensation plans.

See Part III, Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters under the heading "Equity Compensation Plan Information" herein.

(b) Use of Proceeds

Not applicable.

(c) Issuer Purchases of Equity Securities

2012	Total Number of Shares Purchased (a)	Average Price Paid Per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs (a)
October 1 - October 30	4,575,956	$46.13	4,575,956	N/A
November 1 - November 30	2,296,351	44.52	2,296,351	N/A
December 1 - December 30	—	N/A	N/A	N/A
Total	6,872,307	$45.59	6,872,307	N/A

(a) In July 2012, Southern Company announced that it planned to use the proceeds received from stock options exercises during 2012 (including $317 million received through June 30, 2012) to repurchase shares to partially offset the incremental shares issued under its employee and director stock plans. In September 2012, Southern Company engaged an agent to repurchase shares of Southern Company common stock on an ongoing basis to partially offset the incremental shares issued under its employee and director stock plans. As of December 31, 2012, Southern Company had repurchased a total of 9,439,561 shares under this program. In January 2013, Southern Company announced that it plans to continue this program through 2015. Pursuant to approval by the Board of Directors, Southern Company may repurchase shares through open market purchases or privately negotiated transactions, in accordance with applicable securities laws.

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Item 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FINANCIAL CONDITION AND LIQUIDITY – "Market Price Risk" of each of the registrants in Item 7 herein and Note 1 of each of the registrant's financial statements under "Financial Instruments" in Item 8 herein. See also Note 10 to the financial statements of Southern Company, Alabama Power, and Georgia Power, Note 9 to the financial statements of Gulf Power and Mississippi Power, and Note 8 to the financial statements of Southern Power in Item 8 herein.

Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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Item 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

Item 9A. CONTROLS AND PROCEDURES

Disclosure Controls And Procedures.

As of the end of the period covered by this annual report, Southern Company, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, and Southern Power conducted separate evaluations under the supervision and with the participation of each company's management, including the Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of the disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934). Based upon these evaluations, the Chief Executive Officer and the Chief Financial Officer, in each case, concluded that the disclosure controls and procedures are effective.

Internal Control Over Financial Reporting.

(a) Management's Annual Report on Internal Control Over Financial Reporting.

Southern Company's Management's Report on Internal Control Over Financial Reporting is included on page II-9 of this Form 10-K.

Alabama Power's Management's Report on Internal Control Over Financial Reporting is included on page II-119 of this Form 10-K.

Georgia Power's Management's Report on Internal Control Over Financial Reporting is included on page II-201 of this Form 10-K.

Gulf Power's Management's Report on Internal Control Over Financial Reporting is included on page II-285 of this Form 10-K.

Mississippi Power's Management's Report on Internal Control Over Financial Reporting is included on page II-356 of this Form 10-K.

Southern Power's Management's Report on Internal Control Over Financial Reporting is included on page II-444 of this Form 10-K.

(b) Attestation Report of the Registered Public Accounting Firm.

The report of Deloitte & Touche LLP, Southern Company's independent registered public accounting firm, regarding Southern Company's internal control over financial reporting is included on page II-10 of this Form 10-K.

Not applicable to Alabama Power, Georgia Power, Gulf Power, Mississippi Power, and Southern Power because these companies are not accelerated filers or large accelerated filers.

(c) Changes in internal controls.

There have been no changes in Southern Company's, Alabama Power's, Georgia Power's, Gulf Power's, Mississippi Power's, or Southern Power's internal control over financial reporting (as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934) during the fourth quarter 2012 that have materially affected or are reasonably likely to materially affect Southern Company's, Alabama Power's, Georgia Power's, Gulf Power's, Mississippi Power's, or Southern Power's internal control over financial reporting.

Item 9B. OTHER INFORMATION

On February 25, 2013, Gulf Power issued to Southern Company, in a private placement, 400,000 shares of Gulf Power's common stock, no par value, for an aggregate purchase price of $40,000,000. There were no underwriting discounts or commissions. The issuance to Southern Company was exempt from registration under the Securities Act of 1933, as amended (Act), pursuant to Section 4(2) of the Act because it was a transaction by an issuer that did not involve a public offering.

THE SOUTHERN COMPANY
AND SUBSIDIARY COMPANIES

FINANCIAL SECTION

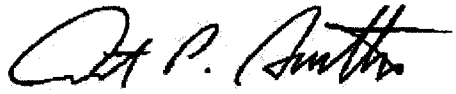
MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING
Southern Company and Subsidiary Companies 2012 Annual Report

The management of The Southern Company (Southern Company) is responsible for establishing and maintaining an adequate system of internal control over financial reporting as required by the Sarbanes-Oxley Act of 2002 and as defined in Exchange Act Rule 13a-15(f). A control system can provide only reasonable, not absolute, assurance that the objectives of the control system are met.

Under management's supervision, an evaluation of the design and effectiveness of Southern Company's internal control over financial reporting was conducted based on the framework in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, management concluded that Southern Company's internal control over financial reporting was effective as of December 31, 2012.

Deloitte & Touche LLP, an independent registered public accounting firm, as auditors of Southern Company's financial statements, has issued an attestation report on the effectiveness of Southern Company's internal control over financial reporting as of December 31, 2012. Deloitte & Touche LLP's report on Southern Company's internal control over financial reporting is included herein.

Thomas A. Fanning
Chairman, President, and Chief Executive Officer



Art P. Beattie
Executive Vice President and Chief Financial Officer

February 27, 2013

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
The Southern Company

We have audited the accompanying consolidated balance sheets and consolidated statements of capitalization of The Southern Company and Subsidiary Companies (the Company) as of December 31, 2012 and 2011, and the related consolidated statements of income, comprehensive income, stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2012. We also have audited the Company's internal control over financial reporting as of December 31, 2012, based on criteria established in *Internal Control - Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for these financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting (page II-9). Our responsibility is to express an opinion on these financial statements and an opinion on the Company's internal control over financial reporting based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the consolidated financial statements (pages II-47 to II-114) referred to above present fairly, in all material respects, the financial position of Southern Company and Subsidiary Companies as of December 31, 2012 and 2011, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2012, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2012, based on the criteria established in *Internal Control - Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

Deloitte & Touche LLP

Atlanta, Georgia
February 27, 2013

OVERVIEW

Business Activities

The Southern Company (Southern Company or the Company) is a holding company that owns all of the common stock of the traditional operating companies – Alabama Power Company (Alabama Power), Georgia Power Company (Georgia Power), Gulf Power Company (Gulf Power), and Mississippi Power Company (Mississippi Power) – and Southern Power Company (Southern Power), and other direct and indirect subsidiaries (together, the Southern Company system). The primary business of the Southern Company system is electricity sales by the traditional operating companies and Southern Power. The four traditional operating companies are vertically integrated utilities providing electric service in four Southeastern states. Southern Power constructs, acquires, owns, and manages generation assets, including renewable energy projects, and sells electricity at market-based rates in the wholesale market.

Many factors affect the opportunities, challenges, and risks of the Southern Company system's electricity business. These factors include the traditional operating companies' ability to maintain a constructive regulatory environment, to maintain and grow energy sales given economic conditions, and to effectively manage and secure timely recovery of costs. These costs include those related to projected long-term demand growth, increasingly stringent environmental standards, fuel, capital expenditures, including new plants, and restoration following major storms. Each of the traditional operating companies has various regulatory mechanisms that operate to address cost recovery. Appropriately balancing required costs and capital expenditures with customer prices will continue to challenge the Southern Company system for the foreseeable future.

Another major factor is the profitability of the competitive market-based wholesale generating business. Southern Power continues to execute its strategy through a combination of acquiring and constructing new power plants, including renewable energy projects, and by entering into power purchase agreements (PPAs) primarily with investor-owned utilities, independent power producers, municipalities, and electric cooperatives.

Southern Company's other business activities include investments in leveraged lease projects and telecommunications. Management continues to evaluate the contribution of each of these activities to total shareholder return and may pursue acquisitions and dispositions accordingly.

Key Performance Indicators

In striving to achieve superior risk-adjusted returns while providing cost-effective energy to more than four million customers, the Southern Company system continues to focus on several key performance indicators. These indicators include customer satisfaction, plant availability, system reliability, and earnings per share (EPS). Southern Company's financial success is directly tied to customer satisfaction. Key elements of ensuring customer satisfaction include outstanding service, high reliability, and competitive prices. Management uses customer satisfaction surveys and reliability indicators to evaluate the results of the Southern Company system.

Peak season equivalent forced outage rate (Peak Season EFOR) is an indicator of fossil/hydro plant availability and efficient generation fleet operations during the months when generation needs are greatest. The rate is calculated by dividing the number of hours of forced outages by total generation hours. The fossil/hydro 2012 Peak Season EFOR was better than the target, excluding the impact of Hurricane Isaac in August 2012. Transmission and distribution system reliability performance is measured by the frequency and duration of outages. Performance targets for reliability are set internally based on historical performance. The performance for 2012 was better than the target for these reliability measures.

Southern Company's 2012 results compared with its targets for some of these key indicators are reflected in the following chart:

Key Performance Indicator	2012 Target Performance	2012 Actual Performance
System Customer Satisfaction	Top quartile in customer surveys	Top quartile
Peak Season System EFOR — fossil/hydro*	4.99% or less	2.81%
Basic EPS	$2.58 — $2.70	$2.70
EPS, excluding the MC Asset Recovery insurance settlement**		$2.68

*Excluding impact of Hurricane Isaac

**Southern Company filed an insurance claim in 2009 to recover a portion of the MC Asset Recovery settlement and received a nontaxable $25 million payment from its insurance provider on June 14, 2012. Additionally, legal fees related to this insurance settlement totaled approximately $6 million. As a result, the net reduction to expense for this insurance settlement was approximately $19 million. Southern Company management uses the non-generally accepted accounting principles (GAAP) measure of EPS, excluding the MC Asset Recovery insurance settlement, to evaluate the performance of Southern Company's ongoing business activities. Southern Company believes the presentation of this non-GAAP measure of earnings and EPS excluding the MC Asset Recovery insurance settlement is useful for investors because it provides earnings information that is consistent with the historical and ongoing business activities of the Company. The presentation of this information is not meant to be considered a substitute for financial measures prepared in accordance with GAAP. See Note 3 to the financial statements under "Insurance Recovery" for additional information.

See RESULTS OF OPERATIONS herein for additional information on the Company's financial performance. The performance achieved in 2012 reflects the continued emphasis that management places on these indicators as well as the commitment shown by employees in achieving or exceeding management's expectations.

Earnings

Southern Company's net income after dividends on preferred and preference stock of subsidiaries was $2.35 billion in 2012, an increase of $147 million, or 6.7%, from the prior year. The increase was primarily the result of lower operations and maintenance expenses resulting from cost containment efforts in 2012, increases in revenues associated with the elimination of a tax-related adjustment under Alabama Power's rate structure, an increase related to retail revenue rate effects at Georgia Power, and an increase in revenues due to increases in retail base rates at Gulf Power. Also contributing to the increase were higher capacity revenues and an increase in retail sales growth. The increases were partially offset by milder weather and an increase in depreciation on additional plant in service related to new generation, transmission, distribution, and environmental projects.

Southern Company's net income after dividends on preferred and preference stock of subsidiaries was $2.20 billion in 2011, an increase of $228 million, or 11.5%, from the prior year. The increase was primarily the result of increases in Georgia Power's retail base revenues as authorized under the 2010 Alternative Rate Plan for the years 2011 through 2013 (2010 ARP) and the recovery of financing costs through the Nuclear Construction Cost Recovery (NCCR) tariff. Also contributing to the increase were increases in energy and capacity revenues at Southern Power and a reduction in operations and maintenance expenses primarily at Alabama Power. The 2011 increase was partially offset by decreases in weather-related revenues due to closer to normal weather in 2011 compared to 2010, a decrease in the amortization of the regulatory liability related to other cost of removal obligations at Georgia Power, a decrease in wholesale revenues primarily at Alabama Power, and a reduction in allowance for funds used during construction (AFUDC) equity. Net income after dividends on preferred and preference stock of subsidiaries was $1.98 billion in 2010.

Basic EPS was $2.70 in 2012, $2.57 in 2011, and $2.37 in 2010. Diluted EPS, which factors in additional shares related to stock-based compensation, was $2.67 in 2012, $2.55 in 2011, and $2.36 in 2010. EPS for 2012 was negatively impacted by $0.05 per share as a result of an increase in the average shares outstanding.

Dividends

Southern Company has paid dividends on its common stock since 1948. Dividends paid per share of common stock were $1.9425 in 2012, $1.8725 in 2011, and $1.8025 in 2010. In January 2013, Southern Company declared a quarterly dividend of 49.00 cents per share. This is the 261st consecutive quarter that Southern Company has paid a dividend equal to or higher than the previous quarter. The Company targets a dividend payout ratio of approximately 70% to 75% of net income. For 2012, the actual payout ratio was 71.9%, while the payout ratio of net income excluding the MC Asset Recovery insurance settlement was 72.5%.

RESULTS OF OPERATIONS

Discussion of the results of operations is divided into two parts – the Southern Company system's primary business of electricity sales and its other business activities.

	Amount		
	2012	2011	2010
		(in millions)	
Electricity business	**$ 2,321**	$ 2,214	$ 1,991
Other business activities	**29**	(11)	(16)
Net income	**$ 2,350**	$ 2,203	$ 1,975

Electricity Business

Southern Company's electric utilities generate and sell electricity to retail and wholesale customers in the Southeast.

A condensed statement of income for the electricity business follows:

	Amount	Increase (Decrease) from Prior Year	
	2012	**2012**	2011
		(in millions)	
Electric operating revenues	**$ 16,478**	**$ (1,109)**	$ 213
Fuel	**5,057**	**(1,205)**	(437)
Purchased power	**544**	**(64)**	45
Other operations and maintenance	**3,695**	**(147)**	(63)
Depreciation and amortization	**1,772**	**72**	205
Taxes other than income taxes	**912**	**13**	32
Total electric operating expenses	**11,980**	**(1,331)**	(218)
Operating income	**4,498**	**222**	431
Allowance for equity funds used during construction	**143**	**(10)**	(41)
Interest income	**22**	**3**	(3)
Interest expense, net of amounts capitalized	**820**	**17**	(30)
Other income (expense), net	**(57)**	**16**	(15)
Income taxes	**1,400**	**107**	179
Net income	**2,386**	**107**	223
Dividends on preferred and preference stock of subsidiaries	**65**	**—**	—
Net income after dividends on preferred and preference stock of subsidiaries	**$ 2,321**	**$ 107**	$ 223

Electric Operating Revenues

Details of electric operating revenues were as follows:

	Amount	
	2012	2011
	(in millions)	
Retail — prior year	$ 15,071	$ 14,791
Estimated change in —		
Rates and pricing	296	793
Sales growth (decline)	39	38
Weather	(282)	(279)
Fuel and other cost recovery	(937)	(272)
Retail — current year	14,187	15,071
Wholesale revenues	1,675	1,905
Other electric operating revenues	616	611
Electric operating revenues	$ 16,478	$ 17,587
Percent change	(6.3)%	1.2%

Retail revenues decreased $884 million, or 5.9%, in 2012 as compared to the prior year. The significant factors driving this change are shown in the preceding table. The increase in rates and pricing in 2012 was primarily due to increases in retail revenues at Georgia Power due to base tariff increases effective April 1, 2012 related to placing Plant McDonough-Atkinson Units 4 and 5 in service, as well as the collection of financing costs associated with the construction of two new nuclear generating units at Plant Vogtle (Plant Vogtle Units 3 and 4) through the NCCR tariff and demand-side management programs effective January 1, 2012, as approved by the Georgia Public Service Commission (PSC), and the rate pricing effect of decreased customer usage. Also contributing to the increase were the elimination of a tax-related adjustment under Alabama Power's rate structure that was effective with October 2011 billings and higher revenues due to increases in retail base rates at Gulf Power. These increases were partially offset by lower contributions from market-driven rates from commercial and industrial customers at Georgia Power and decreased revenues under rate certificated new plant environmental (Rate CNP Environmental) at Alabama Power.

Retail revenues increased $280 million, or 1.9%, in 2011 as compared to the prior year. The significant factors driving this change are shown in the preceding table. The increase in rates and pricing in 2011 was primarily due to increases in Georgia Power's retail base revenues as authorized under the 2010 ARP, which became effective January 1, 2011. The increase in base revenues at Georgia Power also included the collection of financing costs associated with the construction of Plant Vogtle Units 3 and 4 through the NCCR tariff effective January 1, 2011. See "Allowance for Equity Funds Used During Construction" and "Interest Expense, Net of Amounts Capitalized" herein for additional information. Also contributing to the increase in rates and pricing in 2011 were revenues associated with Alabama Power's Rate CNP Environmental due to the completion of construction projects related to environmental mandates and the elimination of a tax-related adjustment under Alabama Power's rate structure.

See FUTURE EARNINGS POTENTIAL – "PSC Matters – Alabama Power – Retail Rate Adjustments" and "PSC Matters – Georgia Power – Rate Plans" herein for additional information. Also see "Energy Sales" below for a discussion of changes in the volume of energy sold, including changes related to sales growth (decline) and weather.

Electric rates for the traditional operating companies include provisions to adjust billings for fluctuations in fuel costs, including the energy component of purchased power costs. Under these provisions, fuel revenues generally equal fuel expenses, including the energy component of purchased power costs, and do not affect net income. The traditional operating companies may also have one or more regulatory mechanisms to recover other costs such as environmental, storm damage, new plants, and PPAs.

Wholesale revenues consist of PPAs with investor-owned utilities and electric cooperatives, unit power sales contracts, and short-term opportunity sales. Wholesale revenues from PPAs and unit power sales contracts have both capacity and energy components. Capacity revenues reflect the recovery of fixed costs and a return on investment. Energy revenues will vary depending on fuel prices, the market prices of wholesale energy compared to the Southern Company system's generation, demand for energy within the Southern Company system's service territory, and the availability of the Southern Company system's generation. Increases and decreases in energy revenues that are driven by fuel prices are accompanied by an increase or decrease in fuel costs and do not

have a significant impact on net income. Short-term opportunity sales are made at market-based rates that generally provide a margin above the Southern Company system's variable cost to produce the energy.

In 2012, wholesale revenues decreased $230 million, or 12.1%, as compared to the prior year due to a $292 million decrease in energy sales primarily due to a reduction in the average price of energy and lower customer demand, partially offset by a $62 million increase in capacity revenues.

In 2011, wholesale revenues decreased $89 million, or 4.5%, as compared to the prior year due to decreased energy revenues. This decrease was primarily due to a decrease in wholesale revenues at Alabama Power due to the expiration of long-term unit power sales contracts in May 2010 and the capacity subject to those contracts being made available for retail service starting in June 2010, as well as lower energy and capacity revenues associated with the expiration of PPAs at Southern Power. The decrease was partially offset by higher energy and capacity revenues under new PPAs at Southern Power.

Revenues associated with PPAs and opportunity sales were as follows:

	2012	2011	2010
		(in millions)	
Other power sales —			
Capacity and other	**$ 827**	$ 767	$ 684
Energy	**776**	1,035	1,034
Total	**$ 1,603**	$ 1,802	$ 1,718

Kilowatt-hour (KWH) sales under unit power sales contracts decreased 65.2% and 69.6% in 2012 and 2011, respectively, as compared to the prior years. In addition, fluctuations in natural gas prices, which is the primary fuel source for unit power sales contracts, influence changes in energy sales. However, because the energy is generally sold at variable cost, fluctuations in energy sales have a minimal effect on earnings. The capacity and energy components of the unit power sales contracts were as follows:

	2012	2011	2010
		(in millions)	
Unit power sales —			
Capacity	**$ 55**	$ 53	$ 136
Energy	**17**	50	140
Total	**$ 72**	$ 103	$ 276

Other Electric Revenues

Other electric revenues increased $5 million, or 0.8%, and $22 million, or 3.7%, in 2012 and 2011, respectively, as compared to the prior years. Other electric revenues increased in 2012 primarily due to an increase in rents from electric property. The 2011 increase in other electric revenues was primarily a result of an increase in transmission revenues at Georgia Power.

Energy Sales

Changes in revenues are influenced heavily by the change in the volume of energy sold from year to year. KWH sales for 2012 and the percent change by year were as follows:

	Total KWHs	Total KWH Percent Change		Weather-Adjusted Percent Change	
	2012	**2012**	2011	**2012**	2011
	(in billions)				
Residential	**50.4**	**(5.4)%**	(7.7)%	**1.1%**	—%
Commercial	**53.0**	**(1.6)**	(2.9)	**(0.2)**	(0.3)
Industrial	**51.7**	**0.2**	3.2	**0.2**	3.3
Other	**0.9**	**(1.8)**	(0.8)	**(1.4)**	(0.7)
Total retail	**156.0**	**(2.3)**	(2.7)	**0.4%**	1.0%
Wholesale	**27.6**	**(9.2)**	(6.8)		
Total energy sales	**183.6**	**(3.4)%**	(3.4)%		

Changes in retail energy sales are comprised of changes in electricity usage by customers, changes in weather, and changes in the number of customers. Retail energy sales decreased 3.6 billion KWHs in 2012 as compared to the prior year. This decrease was primarily the result of milder weather in 2012, partially offset by customer growth and an increase in customer demand primarily in the residential class. Retail energy sales decreased 4.5 billion KWHs in 2011 as compared to the prior year. This decrease was primarily the result of closer to normal weather in 2011 compared to 2010, partially offset by an increase in industrial KWH sales. Increased demand in the primary metals and fabricated metals sectors was the main contributor to the increase in industrial KWH sales. The number of customers in 2011 was flat when compared to 2010.

Wholesale energy sales decreased 2.8 billion KWHs in 2012 and 2.2 billion KWHs in 2011 as compared to the prior years. The decrease in wholesale energy sales in 2012 was primarily related to lower customer demand resulting from milder weather in 2012. The decrease in wholesale energy sales in 2011 was primarily related to the expiration of long-term unit power sales contracts in May 2010 at Alabama Power and the capacity subject to those contracts being made available for retail service starting in June 2010. This decrease was partially offset by increased energy sales under new PPAs at Southern Power.

Fuel and Purchased Power Expenses

Fuel costs constitute the single largest expense for the electric utilities. The mix of fuel sources for generation of electricity is determined primarily by demand, the unit cost of fuel consumed, and the availability of generating units. Additionally, the electric utilities purchase a portion of their electricity needs from the wholesale market.

Details of generation and purchased power by the electric utilities were as follows:

	2012	2011	2010
Total generation *(billions of KWHs)*	**175**	186	196
Total purchased power *(billions of KWHs)*	**16**	12	10
Sources of generation *(percent)* —			
Coal	**38**	52	58
Nuclear	**18**	16	15
Gas	**42**	30	25
Hydro	**2**	2	2
Cost of fuel, generated *(cents per net KWH)* —			
Coal	**3.96**	4.02	3.93
Nuclear	**0.83**	0.72	0.63
Gas	**2.86**	3.89	4.27
Average cost of fuel, generated *(cents per net KWH)*	**2.93**	3.43	3.50
Average cost of purchased power *(cents per net KWH)* *	**4.45**	6.32	6.98

* Average cost of purchased power includes fuel purchased by the electric utilities for tolling agreements where power is generated by the provider.

In 2012, total fuel and purchased power expenses were $5.6 billion, a decrease of $1.3 billion, or 18.5%, as compared to the prior year. This decrease was primarily the result of a $1.0 billion decrease in the average cost of fuel and purchased power and a $519 million decrease in the volume of KWHs generated as a result of milder weather in 2012, partially offset by a $270 million increase in the volume of KWHs purchased.

In 2011, total fuel and purchased power expenses were $6.9 billion, a decrease of $392 million, or 5.4%, as compared to the prior year. This decrease was primarily the result of a $349 million decrease in the volume of KWHs generated and a $206 million decrease in the average cost of fuel and purchased power, partially offset by a $163 million increase in the volume of KWHs purchased.

From an overall global market perspective, coal prices decreased from levels experienced in 2011 due to lower demand. In the U.S., this decrease was due primarily to relatively lower domestic natural gas prices that contributed to displacement of coal generation by natural gas-fueled generating units. Lower domestic natural gas prices in 2012 were driven by continued robust supplies, including production from shale gas, and only modest increases in overall U.S. consumption.

Uranium prices began to decrease during the second half of 2012 as extended reactor shutdowns in Europe and Asia caused global demand for uranium to drop below the level of previous years, while production increased. Changes in the cost of fuel for nuclear generation tend to lag behind changes in uranium market prices. Even though uranium prices decreased slightly during 2012, the cost of fuel for nuclear generation increased in 2012, reflecting the higher uranium prices from previous years when the uranium was purchased.

Fuel and purchased power energy transactions at the traditional operating companies are generally offset by fuel revenues and do not have a significant impact on net income. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Fuel Cost Recovery" herein for additional information. Fuel expenses incurred under Southern Power's PPAs are generally the responsibility of the counterparties and do not significantly impact net income.

Fuel

In 2012, fuel expense was $5.1 billion, a decrease of $1.2 billion, or 19.2%, as compared to the prior year. The decrease was primarily due to a 26.5% decrease in the average cost of natural gas per KWH generated, a higher percentage of generation from lower-cost natural gas-fired resources, and lower customer demand mainly due to milder weather in 2012.

In 2011, fuel expense was $6.3 billion, a decrease of $437 million, or 6.5%, as compared to the prior year. The decrease was primarily due to an 8.9% decrease in the average cost of natural gas per KWH generated and lower demand primarily due to closer to normal weather in 2011 compared to 2010.

Purchased Power

In 2012, purchased power expense was $544 million, a decrease of $64 million, or 10.5%, as compared to the prior year. The decrease was due to a 29.6% decrease in the average cost per KWH purchased, partially offset by a 35.1% increase in the volume of KWHs purchased as the market cost of available energy was lower than the marginal cost of generation available.

In 2011, purchased power expense was $608 million, an increase of $45 million, or 8.0%, as compared to the prior year. The increase was due to a 23.9% increase in the volume of KWHs purchased as the market cost of available energy was lower than the marginal cost of generation available, partially offset by a 9.5% decrease in the average cost per KWH purchased.

Energy purchases will vary depending on demand for energy within the Southern Company system's service territory, the market prices of wholesale energy as compared to the cost of the Southern Company system's generation, and the availability of the Southern Company system's generation.

Other Operations and Maintenance Expenses

Other operations and maintenance expenses were $3.7 billion and $3.8 billion, decreasing $147 million, or 3.8%, and $63 million, or 1.6%, in 2012 and 2011, respectively, as compared to the prior years. Discussion of significant variances for components of other operations and maintenance expenses follows.

Other production expenses at fossil, hydro, and nuclear plants decreased $110 million in 2012 and increased $2 million in 2011 as compared to the prior years. Production expenses fluctuate from year to year due to variations in outage schedules and changes in the cost of labor and materials. Other production expenses decreased in 2012 primarily due to a decrease in scheduled outage and maintenance costs and commodity and labor costs, which was primarily the result of cost containment efforts to offset the effect of milder weather in 2012. Also contributing to the decrease was a $35 million decrease at Mississippi Power related to the expiration of the operating lease for Plant Daniel Units 3 and 4, which was offset by a $35 million increase at Alabama Power primarily related to a change in the nuclear maintenance outage accounting process associated with routine refueling activities, as approved by the Alabama PSC in 2010. See FINANCIAL CONDITION AND LIQUIDITY – "Purchase of the Plant Daniel Combined Cycle Generating Units" herein for additional information. Other production expenses increased in 2011 mainly due to a $29 million increase in commodity and labor costs and a $26 million increase in outage and maintenance costs. These increases were largely offset by a decrease in nuclear outage expense at Alabama Power, primarily related to the change in the nuclear maintenance outage accounting process. As a result, Alabama Power did not recognize any nuclear maintenance outage expenses in 2011, reducing nuclear production expense by approximately $50 million as compared to 2010. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Alabama Power – Nuclear Outage Accounting Order" herein for additional information.

Transmission and distribution expenses decreased $75 million and $80 million in 2012 and 2011, respectively, as compared to the prior years. Transmission and distribution expenses fluctuate from year to year due to variations in maintenance schedules and normal changes in the cost of labor and materials. Transmission and distribution expenses decreased in 2012 primarily due to cost containment efforts to offset the effects of the milder weather in 2012 and a reduction in accruals at Alabama Power to the natural disaster reserve (NDR). Transmission and distribution expenses decreased in 2011 primarily due to reductions in spending related to vegetation management and a reduction in accruals to the NDR at Alabama Power. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Alabama Power – Natural Disaster Reserve" herein for additional information.

Customer accounts, sales, and service expenses decreased $20 million in 2012 and increased $33 million in 2011 as compared to the prior years. Customer accounts, sales, and service expenses decreased in 2012 primarily due to a decrease in uncollectible account expense at Georgia Power. Customer accounts, sales, and service expenses increased in 2011 primarily due to a $24 million increase in customer service expense primarily related to new demand side management programs at Georgia Power and a $9 million increase in records and collection expense.

Administrative and general expenses increased $58 million in 2012 and decreased $18 million in 2011 as compared to the prior years. Administrative and general expenses increased in 2012 primarily as a result of an increase in pension costs. Administrative and general expenses decreased in 2011 primarily as a result of a $10 million decrease in property insurance cost and a $7 million decrease in injuries and damages reserve costs.

Depreciation and Amortization

Depreciation and amortization increased $72 million, or 4.2%, in 2012 as compared to the prior year primarily as a result of additional plant in service related to new generation at Georgia Power's Plant McDonough-Atkinson Units 4 and 5, additional plant in service at Southern Power, as well as transmission, distribution, and environmental projects, partially offset by amortization of the regulatory liability for state income tax credits at Georgia Power as authorized by the Georgia PSC. See Note 1 to the financial statements under "Regulatory Assets and Liabilities" for additional information.

Depreciation and amortization increased $205 million, or 13.7%, in 2011 as compared to the prior year primarily as a result of a $142 million decrease in the amortization of the regulatory liability related to other cost of removal obligations at Georgia Power as authorized by the Georgia PSC and additional depreciation on plant in service related to environmental, transmission, and distribution projects. See Note 3 to the financial statements under "Retail Regulatory Matters – Georgia Power – Rate Plans" for additional information regarding Georgia Power's cost of removal amortization.

See Note 1 to the financial statements under "Depreciation and Amortization" for additional information.

Taxes Other Than Income Taxes

Taxes other than income taxes increased $13 million, or 1.4%, in 2012 as compared to the prior year primarily due to increases in property taxes, partially offset by a decrease in municipal franchise fees. Taxes other than income taxes increased $32 million, or 3.7%, in 2011 compared to the prior year primarily due to increases in property taxes and municipal franchise fees at Georgia Power and increases in state and municipal public utility license tax bases at Alabama Power. Increases in franchise fees are associated with increases in revenues from energy sales.

Allowance for Equity Funds Used During Construction

AFUDC equity decreased $10 million, or 6.5%, in 2012 as compared to the prior year primarily due to the completion of Georgia Power's Plant McDonough-Atkinson Units 4, 5, and 6 in December 2011, April 2012, and October 2012, respectively, partially offset by increases in construction work in progress (CWIP) related to Mississippi Power's integrated coal gasification combined cycle facility under construction in Kemper County, Mississippi (Kemper IGCC), which began construction in 2010.

AFUDC equity decreased $41 million, or 21.1%, in 2011 as compared to the prior year primarily due to the inclusion of Georgia Power's construction costs for Plant Vogtle Units 3 and 4 in rate base effective January 1, 2011 in accordance with the Georgia Nuclear Energy Financing Act and a Georgia PSC order. This action reduced the amount of AFUDC capitalized, with an offsetting increase in operating revenues through the NCCR tariff. See Note 3 to the financial statements under "Retail Regulatory Matters – Georgia Power – Nuclear Construction" for additional information. Also contributing to the decrease was the completion of construction projects related to environmental mandates at Alabama Power. The 2011 decrease was partially offset by CWIP related to Mississippi Power's Kemper IGCC.

Interest Expense, Net of Amounts Capitalized

Total interest charges and other financing costs increased $17 million, or 2.1%, in 2012 as compared to the prior year primarily due to a $23 million reduction in interest expense in 2011 at Georgia Power resulting from the settlement of litigation with the Georgia Department of Revenue (DOR), a decrease in AFUDC debt at Georgia Power due to the completion of Plant McDonough-Atkinson Units 4 and 5, and a net increase in interest expense related to senior notes and other long-term debt. The increases were partially offset by a decrease in interest expense on existing variable rate pollution control revenue bonds, an increase in capitalized interest primarily resulting from AFUDC debt associated with the Kemper IGCC at Mississippi Power, and a decrease related to the conclusion of certain state and federal income tax audits.

Total interest charges and other financing costs decreased $30 million, or 3.6%, in 2011 as compared to the prior year primarily due to a reduction of $23 million in interest expense at Georgia Power related to the settlement of litigation with the Georgia DOR and lower interest expense on existing variable rate pollution control revenue bonds at Georgia Power. The decrease was partially offset by a reduction in AFUDC debt at Georgia Power due to the inclusion of construction costs for Plant Vogtle Units 3 and 4 in rate base.

Other Income (Expense), Net

Other income (expense), net increased $16 million, or 21.9%, in 2012 and decreased $15 million, or 25.9%, in 2011 as compared to the prior years primarily due to a make-whole premium payment in connection with the early redemption of senior notes at Southern Power in 2011.

Income Taxes

Income taxes increased $107 million, or 8.3%, in 2012 as compared to the prior year primarily due to higher pre-tax earnings, an increase in non-deductible book depreciation, and a decrease in non-taxable AFUDC equity, partially offset by state income tax credits.

Income taxes increased $179 million, or 16.1%, in 2011 as compared to the prior year primarily due to higher pre-tax earnings, a decrease in 2010 in uncertain tax positions at Georgia Power related to state income tax credits, and a reduction in AFUDC equity, which is non-taxable.

Other Business Activities

Southern Company's other business activities include the parent company (which does not allocate operating expenses to business units), investments in leveraged lease projects, and telecommunications. These businesses are classified in general categories and may comprise one or both of the following subsidiaries: Southern Company Holdings, Inc. invests in various projects, including leveraged lease projects, and Southern Communications Services, Inc. (SouthernLINC Wireless) provides digital wireless communications for use by Southern Company and its subsidiary companies and also markets these services to the public and provides fiber cable services within the Southeast.

A condensed statement of income for Southern Company's other business activities follows:

	Amount	Increase (Decrease) from Prior Year	
	2012	2012	2011
		(in millions)	
Operating revenues	$ 59	$ (11)	$ (12)
Other operations and maintenance	96	—	(9)
MC Asset Recovery litigation settlement	(19)	(19)	—
Depreciation and amortization	15	(2)	(1)
Taxes other than income taxes	2	—	—
Total operating expenses	94	(21)	(10)
Operating income (loss)	(35)	10	(2)
Interest income	18	16	—
Equity in income (losses) of unconsolidated subsidiaries	(2)	—	—
Leveraged lease income (losses)	21	(4)	7
Other income (expense), net	—	11	6
Interest expense	39	(15)	(8)
Income taxes	(66)	8	14
Net income (loss)	$ 29	$ 40	$ 5

Operating Revenues

Southern Company's non-electric operating revenues from these other business activities decreased $11 million, or 15.7%, and $12 million, or 14.6%, in 2012 and 2011, respectively, as compared to the prior years. The decreases were primarily the result of decreases in revenues at SouthernLINC Wireless related to lower average per subscriber revenue and fewer subscribers due to continued competition in the industry.

Other Operations and Maintenance Expenses

In 2012, the change in other operations and maintenance expenses for these other businesses was not material. Other operations and maintenance expenses for these other businesses decreased $9 million, or 8.6%, in 2011 as compared to the prior year. The decrease in 2011 was primarily the result of lower administrative and general expenses.

MC Asset Recovery Insurance Settlement

On June 14, 2012, Southern Company received an insurance recovery related to the litigation settlement with MC Asset Recovery, LLC, which resulted in income of $19 million. See Note 3 to the financial statements under "Insurance Recovery" for additional information.

Interest Income

Interest income for these other businesses increased $16 million in 2012 as compared to the prior year primarily due to the conclusion of certain federal income tax audits. In 2011, the change in interest income for these other businesses was not material.

Leveraged Lease Income (Losses)

Southern Company has several leveraged lease agreements which relate to international and domestic energy generation, distribution, and transportation assets. Southern Company receives federal income tax deductions for depreciation and amortization, as well as interest on long-term debt related to these investments. The change in leveraged lease income (losses) in 2012 compared to 2011 was not material. Leveraged lease income (losses) increased $7 million, or 38.9%, in 2011 as compared to the prior year primarily as a result of changes in the average leveraged lease investment balance. See FUTURE EARNINGS POTENTIAL – "Investments in Leveraged Leases" herein for additional information.

Other Income (Expense), Net

Other income (expense), net for these other businesses increased $11 million in 2012 and $6 million in 2011 as compared to the prior years primarily as a result of decreases in the amount of charitable contributions made by the parent company.

Interest Expense

Total interest charges and other financing costs for these other businesses decreased $15 million, or 27.8%, in 2012 and $8 million, or 12.9%, in 2011 as compared to the prior years primarily due to lower interest rates on existing debt.

Income Taxes

Income taxes for these other businesses increased $8 million, or 10.8%, in 2012 as compared to the prior year primarily as a result of lower pre-tax losses. Income taxes for these other business increased $14 million, or 15.9%, in 2011 as compared to the prior year primarily as a result of lower pre-tax losses and a prior year state tax adjustment related to leveraged leases.

Effects of Inflation

The traditional operating companies are subject to rate regulation that is generally based on the recovery of historical and projected costs. The effects of inflation can create an economic loss since the recovery of costs could be in dollars that have less purchasing power. Southern Power is party to long-term contracts reflecting market-based rates, including inflation expectations. Any adverse effect of inflation on Southern Company's results of operations has not been substantial in recent years.

FUTURE EARNINGS POTENTIAL

General

The four traditional operating companies operate as vertically integrated utilities providing electricity to customers within their service areas in the Southeast. Prices for electricity provided to retail customers are set by state PSCs under cost-based regulatory principles. Prices for wholesale electricity sales, interconnecting transmission lines, and the exchange of electric power are regulated by the Federal Energy Regulatory Commission (FERC). Retail rates and earnings are reviewed and may be adjusted periodically within certain limitations. Southern Power continues to focus on long-term capacity contracts, optimized by limited energy trading activities. See ACCOUNTING POLICIES – "Application of Critical Accounting Policies and Estimates – Electric Utility Regulation" herein and Note 3 to the financial statements for additional information about regulatory matters.

The results of operations for the past three years are not necessarily indicative of future earnings potential. The level of Southern Company's future earnings depends on numerous factors that affect the opportunities, challenges, and risks of the Southern Company system's primary business of selling electricity. These factors include the traditional operating companies' ability to maintain a constructive regulatory environment that continues to allow for the timely recovery of prudently-incurred costs during a time of increasing costs and the successful completion of ongoing construction projects, including construction of generating facilities. Another major factor is the profitability of the competitive wholesale supply business. Future earnings for the electricity business in the near term will depend, in part, upon maintaining energy sales which is subject to a number of factors. These factors include weather, competition, new energy contracts with neighboring utilities and other wholesale customers, energy conservation practiced by customers, the price of electricity, the price elasticity of demand, and the rate of economic growth or decline in the service territory. In addition, the level of future earnings for the wholesale supply business also depends on numerous factors including creditworthiness of customers, total generating capacity available and related costs, future acquisitions and construction of generating facilities, and the successful remarketing of capacity as current contracts expire. Changes in economic conditions impact sales for the traditional operating companies and Southern Power, and the pace of the

economic recovery remains uncertain. The timing and extent of the economic recovery will impact growth and may impact future earnings.

In 2012, the Southern Company system generating capacity increased 2,184 megawatts (MWs), net of retirements of 352 MWs, due to the completion of Plant McDonough-Atkinson Units 5 and 6, the completion of a biomass generating plant, the completion of Plant Cleveland County Units 1 through 4, and the acquisition of three solar photovoltaic facilities. In general, the Southern Company system has constructed or acquired new generating capacity only after entering into long-term capacity contracts for the new facilities or to meet requirements of the Southern Company system's regulated retail markets, both of which are optimized by limited energy trading activities. See "Construction Program" herein for additional information.

As part of its ongoing effort to adapt to changing market conditions, Southern Company continues to evaluate and consider a wide array of potential business strategies. These strategies may include business combinations, partnerships, acquisitions involving other utility or non-utility businesses or properties, disposition of certain assets, internal restructuring, or some combination thereof. Furthermore, Southern Company may engage in new business ventures that arise from competitive and regulatory changes in the utility industry. Pursuit of any of the above strategies, or any combination thereof, may significantly affect the business operations, risks, and financial condition of Southern Company.

Environmental Matters

Compliance costs related to federal and state environmental statutes and regulations could affect earnings if such costs cannot continue to be fully recovered in rates on a timely basis. Environmental compliance spending over the next several years may differ materially from the amounts estimated. The timing, specific requirements, and estimated costs could change as environmental statutes and regulations are adopted or modified. Further, higher costs that are recovered through regulated rates could contribute to reduced demand for electricity, which could negatively affect results of operations, cash flows, and financial condition. See Note 3 to the financial statements under "Environmental Matters" for additional information.

New Source Review Actions

In 1999, the Environmental Protection Agency (EPA) brought a civil action in the U.S. District Court for the Northern District of Georgia against certain Southern Company subsidiaries, including Alabama Power and Georgia Power, alleging that these subsidiaries had violated the New Source Review (NSR) provisions of the Clean Air Act and related state laws at certain coal-fired generating facilities. The EPA alleged NSR violations at five coal-fired generating facilities operated by Alabama Power, including a unit co-owned by Mississippi Power, and three coal-fired generating facilities operated by Georgia Power, including a unit co-owned by Gulf Power. The civil action sought penalties and injunctive relief, including an order requiring installation of the best available control technology at the affected units. The case against Georgia Power (including claims related to the unit co-owned by Gulf Power) was administratively closed in 2001 and has not been reopened. After Alabama Power was dismissed from the original action, the EPA filed a separate action in 2001 against Alabama Power (including claims related to the unit co-owned by Mississippi Power) in the U.S. District Court for the Northern District of Alabama.

In 2006, the U.S. District Court for the Northern District of Alabama entered a consent decree, resolving claims relating to the alleged NSR violations at Plant Miller. In 2010, the EPA dismissed five of its eight remaining claims against Alabama Power, leaving only three claims, including one relating to the unit co-owned by Mississippi Power. In March 2011, the U.S. District Court for the Northern District of Alabama granted Alabama Power summary judgment on all remaining claims and dismissed the case with prejudice. That judgment is on appeal to the U.S. Court of Appeals for the Eleventh Circuit. On February 23, 2012, the EPA filed a motion in the U.S. District Court for the Northern District of Alabama seeking vacatur of the judgment and recusal of the judge in the case involving Alabama Power.

Southern Company believes the traditional operating companies complied with applicable laws and regulations in effect at the time the work in question took place. The Clean Air Act authorizes maximum civil penalties of $25,000 to $37,500 per day, per violation, depending on the date of the alleged violation. An adverse outcome could require substantial capital expenditures that cannot be determined at this time and could possibly require payment of substantial penalties. Such expenditures could affect future results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates. The ultimate outcome of these matters cannot be determined at this time.

Climate Change Litigation

Kivalina Case

In 2008, the Native Village of Kivalina and the City of Kivalina filed a lawsuit in the U.S. District Court for the Northern District of California against several electric utilities (including Southern Company), several oil companies, and a coal company. The plaintiffs allege that the village is being destroyed by erosion allegedly caused by global warming that the plaintiffs attribute to emissions of greenhouse gases by the defendants. The plaintiffs assert claims for public and private nuisance and contend that some of the defendants (including Southern Company) acted in concert and are therefore jointly and severally liable for the plaintiffs' damages. The suit seeks damages for lost property values and for the cost of relocating the village, which is alleged to be $95 million to $400 million. In 2009, the U.S. District Court for the Northern District of California granted the defendants' motions to dismiss the case. On September 21, 2012, the U.S. Court of Appeals for the Ninth Circuit upheld the U.S. District Court for the Northern District of California's dismissal of the case. On November 27, 2012, the U.S. Court of Appeals for the Ninth Circuit denied the plaintiffs' request for review of the decision. On February 25, 2013, the plaintiffs filed a petition for writ of certiorari with the U.S. Supreme Court. Southern Company believes that these claims are without merit. The ultimate outcome of this matter cannot be determined at this time.

Hurricane Katrina Case

In 2005, immediately following Hurricane Katrina, a lawsuit was filed in the U.S. District Court for the Southern District of Mississippi by Ned Comer on behalf of Mississippi residents seeking recovery for property damage and personal injuries caused by Hurricane Katrina. In 2006, the plaintiffs amended the complaint to include Southern Company and many other electric utilities, oil companies, chemical companies, and coal producers. The plaintiffs allege that the defendants contributed to climate change, which contributed to the intensity of Hurricane Katrina. In 2007, the U.S. District Court for the Southern District of Mississippi dismissed the case. On appeal to the U.S. Court of Appeals for the Fifth Circuit, a three-judge panel reversed the U.S. District Court for the Southern District of Mississippi, holding that the case could proceed, but, on rehearing, the full U.S. Court of Appeals for the Fifth Circuit dismissed the plaintiffs' appeal, resulting in reinstatement of the decision of the U.S. District Court for the Southern District of Mississippi in favor of the defendants. In May 2011, the plaintiffs filed an amended version of their class action complaint, arguing that the earlier dismissal was on procedural grounds and under Mississippi law the plaintiffs have a right to re-file. The amended complaint was also filed against numerous chemical, coal, oil, and utility companies, including Alabama Power, Georgia Power, Gulf Power, and Southern Power. On March 20, 2012, the U.S. District Court for the Southern District of Mississippi dismissed the plaintiffs' amended complaint. On April 16, 2012, the plaintiffs appealed the case to the U.S. Court of Appeals for the Fifth Circuit. Southern Company believes that these claims are without merit. The ultimate outcome of this matter cannot be determined at this time.

Environmental Statutes and Regulations

General

The electric utilities' operations are subject to extensive regulation by state and federal environmental agencies under a variety of statutes and regulations governing environmental media, including air, water, and land resources. Applicable statutes include the Clean Air Act; the Clean Water Act; the Comprehensive Environmental Response, Compensation, and Liability Act; the Resource Conservation and Recovery Act; the Toxic Substances Control Act; the Emergency Planning & Community Right-to-Know Act; the Endangered Species Act; and related federal and state regulations. Compliance with these environmental requirements involves significant capital and operating costs, a major portion of which is expected to be recovered through existing ratemaking provisions. Through 2012, the traditional operating companies had invested approximately $8.7 billion in environmental capital retrofit projects to comply with these requirements, with annual totals of approximately $340 million, $300 million, and $500 million for 2012, 2011, and 2010, respectively. The Southern Company system expects that capital expenditures to comply with existing statutes and regulations, including capital expenditures and compliance costs associated with the EPA's final Mercury and Air Toxics Standards (MATS) rule, will be a total of approximately $3.6 billion from 2013 through 2015, with annual totals of approximately $1.0 billion, $1.5 billion, and $1.1 billion for 2013, 2014, and 2015, respectively.

The Southern Company system continues to monitor the development of the EPA's proposed water and coal combustion byproducts rules and to evaluate compliance options. Based on its preliminary analysis and an assumption that coal combustion byproducts will continue to be regulated as non-hazardous solid waste under the proposed rule, the Southern Company system does not anticipate that material compliance costs with respect to these proposed rules will be required during the period of 2013 through 2015. The ultimate capital expenditures and compliance costs with respect to these proposed rules, including additional expenditures required after 2015, will be dependent on the requirements of the final rules and regulations adopted by the EPA and the outcome of any legal challenges to these rules. See "Water Quality" and "Coal Combustion Byproducts" herein for additional

information.

The Southern Company system's ultimate environmental compliance strategy, including potential unit retirement and replacement decisions, and future environmental capital expenditures will be affected by the final requirements of new or revised environmental regulations and regulations relating to global climate change that are promulgated, including the proposed environmental regulations described below; the outcome of any legal challenges to the environmental rules; the cost, availability, and existing inventory of emissions allowances; and the fuel mix of the electric utilities. Compliance costs may arise from existing unit retirements, installation of additional environmental controls, upgrades to the transmission system, and adding or changing fuel sources for certain existing units. The ultimate outcome of these matters cannot be determined at this time. See "PSC Matters – Georgia Power – Integrated Resource Plans" herein for additional information on planned unit retirements and fuel conversions at Georgia Power.

Southern Electric Generating Company (SEGCO) is jointly owned by Alabama Power and Georgia Power. As part of its environmental compliance strategy, SEGCO plans to add natural gas as the primary fuel source for its generating units in 2015. The capacity of SEGCO's units is sold equally to Alabama Power and Georgia Power through a PPA. The impact of SEGCO's ultimate compliance strategy on such PPA costs cannot be determined at this time; however, if such costs cannot continue to be recovered through retail rates, they could have a material financial impact on Southern Company's financial statements. See Note 4 to the financial statements herein for additional information.

Compliance with any new federal or state legislation or regulations relating to air quality, water, coal combustion byproducts, global climate change, or other environmental and health concerns could significantly affect the Company. Although new or revised environmental legislation or regulations could affect many areas of the electric utilities' operations, the full impact of any such changes cannot be determined at this time. Additionally, many of the electric utilities' commercial and industrial customers may also be affected by existing and future environmental requirements, which for some may have the potential to ultimately affect their demand for electricity.

Air Quality

Compliance with the Clean Air Act and resulting regulations has been and will continue to be a significant focus for the Southern Company system. Since 1990, the electric utilities have spent approximately $7.6 billion in reducing and monitoring emissions pursuant to the Clean Air Act. Additional controls are currently planned or under consideration to further reduce air emissions, maintain compliance with existing regulations, and meet new requirements.

The EPA regulates ground level ozone concentrations through implementation of an eight-hour ozone air quality standard. In 2008, the EPA adopted a more stringent eight-hour ozone National Ambient Air Quality Standard, which it began to implement in September 2011. On May 21, 2012, the EPA published its final determination of nonattainment areas based on the 2008 eight-hour ozone air quality standards. The only area within the traditional operating companies' service territory designated as a nonattainment area is a 15-county area within metropolitan Atlanta.

The EPA regulates fine particulate matter concentrations on an annual and 24-hour average basis. All areas within the traditional operating companies' service territory have achieved attainment with the 1997 and 2006 particulate matter National Ambient Air Quality Standards and, in January 2013, the EPA officially redesignated the Birmingham area as attainment under both the annual and 24-hour standards. Redesignation requests for nonattainment areas in Georgia are still pending with the EPA. On January 15, 2013, the EPA published a final rule that increases the stringency of the annual fine particulate matter standard. The new standard could result in the designation of new nonattainment areas within the traditional operating companies' service territories.

Final revisions to the National Ambient Air Quality Standard for sulfur dioxide (SO_2), including the establishment of a new one-hour standard, became effective in 2010 (SO_2 Rule). The EPA plans to issue area designations under this new standard in June 2013, and areas within the Southern Company system's service territory could ultimately be designated as nonattainment. Implementation of the revised SO_2 standard could require additional reductions in SO_2 emissions and increased compliance and operational costs.

Revisions to the National Ambient Air Quality Standard for nitrogen dioxide (NO_2), which established a new one-hour standard, became effective in 2010. On February 29, 2012, the new NO_2 standard became effective. The EPA designated the entire country as "unclassifiable/attainment" under the new standard, with no nonattainment areas designated. However, the new NO_2 standard could result in significant additional compliance and operational costs for units that require new source permitting.

In 2008, the EPA approved a revision to Alabama's State Implementation Plan (SIP) requirements related to opacity, which granted some flexibility to affected sources while requiring compliance with Alabama's stringent opacity limits through use of continuous opacity monitoring system data. In April 2011, the EPA attempted to rescind its previous approval of the Alabama SIP

revision. This decision impacts facilities operated by Alabama Power, including units co-owned by Mississippi Power. Alabama Power filed an appeal of that decision with the U.S. Court of Appeals for the Eleventh Circuit. The EPA's rescission has affected unit availability and increased maintenance and compliance costs. Unless the court resolves Alabama Power's appeal in its favor, the EPA's rescission will continue to affect Alabama Power's operations.

Each of the states in which the Southern Company system has fossil generation is subject to the requirements of the Clean Air Interstate Rule (CAIR), which calls for phased reductions in SO_2 and nitrogen oxide (NO_x) emissions from power plants in 28 eastern states. In 2008, the U.S. Court of Appeals for the District of Columbia Circuit issued decisions invalidating CAIR, but left CAIR compliance requirements in place while the EPA developed a new rule. In August 2011, the EPA adopted the Cross State Air Pollution Rule (CSAPR) to replace CAIR effective January 1, 2012. However, in December 2011, the U. S. Court of Appeals for the District of Columbia Circuit stayed the rule and, on August 21, 2012, vacated CSAPR in its entirety and directed the EPA to continue to administer CAIR pending the EPA's development of a valid replacement. On January 24, 2013, the U.S. Court of Appeals for the District of Columbia Circuit denied requests by the EPA and other parties for rehearing.

The EPA finalized the Clean Air Visibility Rule (CAVR) in 2005, with a goal of restoring natural visibility conditions in certain areas (primarily national parks and wilderness areas) by 2064. The rule involves the application of best available retrofit technology (BART) to certain sources built between 1962 and 1977 and any additional emissions reductions necessary for each designated area to achieve reasonable progress toward the natural visibility conditions goal by 2018 and for each 10-year period thereafter. In 2005, the EPA determined that compliance with CAIR satisfies BART obligations under CAVR, but, on June 7, 2012, the EPA issued a final rule replacing CAIR with CSAPR as an alternative means of satisfying BART obligations. The vacatur of CSAPR creates additional uncertainty with respect to whether additional controls may be required for CAVR and BART compliance.

On February 16, 2012, the EPA published the final MATS rule, which imposes stringent emissions limits for acid gases, mercury, and particulate matter on coal- and oil-fired electric utility steam generating units. Compliance for existing sources is required by April 16, 2015, unless a one-year compliance extension is granted by the state or local air permitting agency.

Numerous petitions for administrative reconsideration of the MATS rule, including a petition by Southern Company and its subsidiaries, have been filed with the EPA. On November 30, 2012, the EPA proposed a reconsideration of certain new source and startup/shutdown issues. The EPA plans to complete its reconsideration rulemaking by March 2013. Challenges to the final rule have also been filed in the U.S. District Court for the District of Columbia by numerous states, environmental organizations, industry groups, and others.

On August 29, 2012, the EPA published proposed revisions to the New Source Performance Standard (NSPS) for Stationary Combustion Turbines (CTs). If finalized as proposed, the revisions would apply the NSPS to all new, reconstructed, and modified CTs (including CTs at combined cycle units), during all periods of operation, including startup and shutdown, and alter the criteria for determining when an existing CT has been reconstructed.

On January 31, 2013, the EPA published the final Industrial Boiler Maximum Achievable Control Technology (IB MACT) rule establishing emissions limits and/or work practice standards for various hazardous air pollutants emitted from industrial boilers, including biomass boilers and start-up boilers. Compliance for existing sources will be required by early 2016. Compliance for new sources will begin upon startup. Georgia Power is evaluating the impact of this final rule and other environmental regulations on the possible conversion of Plant Mitchell Unit 3 from coal to biomass.

On February 12, 2013, the EPA proposed a rule that would require certain states to revise the provisions of their SIPs relating to the regulation of excess emissions at industrial facilities, including fossil fuel-fired generating facilities, during periods of startup, shut-down, or malfunction (SSM). The EPA proposes a determination that the SSM provisions in the SIPs for 36 states (including Alabama, Florida, Georgia, Mississippi, and North Carolina) do not meet the requirements of the Clean Air Act and must be revised within 18 months of the date on which the EPA publishes the final rule. If finalized as proposed, this new requirement could result in significant additional compliance and operational costs.

The Southern Company system has developed and continually updates a comprehensive environmental compliance strategy to assess compliance obligations associated with the existing and new environmental requirements discussed above. The impacts of the eight-hour ozone, fine particulate matter, SO_2 and NO_2 standards, CAIR and any future replacement rule, CAVR, the MATS rule, the NSPS for CTs, the IB MACT rule, and the SSM rule on the Southern Company system cannot be determined at this time and will depend on the specific provisions of recently finalized and future rules, the resolution of pending and future legal challenges, and the development and implementation of rules at the state level. These regulations could result in significant additional compliance costs that could affect future unit retirement and replacement decisions and results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates. Further, higher costs that are recovered

through regulated rates could contribute to reduced demand for electricity, which could negatively impact results of operations, cash flows, and financial condition.

In addition to the federal air quality laws described above, Georgia Power is also subject to the requirements of the 2007 State of Georgia Multi-Pollutant Rule. The Multi-Pollutant Rule is designed to reduce emissions of mercury, SO_2, and NO_x state-wide by requiring the installation of specified control technologies at certain coal-fired generating units by specific dates between December 31, 2008 and December 31, 2015. The State of Georgia also adopted a companion rule that requires a 95% reduction in SO_2 emissions from the controlled units on the same or similar timetable. Through December 31, 2012, Georgia Power had installed the required controls on 11 of its largest coal-fired generating units and is in the process of installing the required controls on two additional units. On February 21, 2013, the State of Georgia released proposed revisions for both the Multi-Pollutant Rule and the SO_2 Rule revising the compliance dates for those units yet to be controlled to make them consistent with the April 2015 compliance date for the MATS rule. According to the State of Georgia, the proposed revisions would also allow the units at Plant Yates to use natural gas as the primary fuel as an alternative to installing controls under the Multi-Pollutant Rule. The revisions to the Multi-Pollutant Rule and the SO_2 Rule are expected to be finalized in April 2013. The ultimate outcome of these matters cannot be determined at this time.

Water Quality

In April 2011, the EPA published a proposed rule that establishes standards for reducing effects on fish and other aquatic life caused by cooling water intake structures at existing power plants and manufacturing facilities. The rule also addresses cooling water intake structures for new units at existing facilities. Compliance with the proposed rule could require changes to existing cooling water intake structures at certain of the traditional operating companies' and Southern Power's generating facilities, and new generating units constructed at existing plants would be required to install closed cycle cooling towers. The EPA has entered into an amended settlement agreement to extend the deadline for issuing a final rule until June 27, 2013. If finalized as proposed, some of the facilities of Southern Company's subsidiaries may be subject to significant additional capital expenditures and compliance costs that could affect future unit retirement and replacement decisions. Also, results of operations, cash flows, and financial condition could be significantly impacted if such costs are not recovered through regulated rates or through PPAs. The ultimate outcome of this rulemaking will depend on the final rule and the outcome of any legal challenges and cannot be determined at this time.

The EPA has announced its determination that revision of the current effluent guidelines for steam electric power plants is warranted and has stated that it intends to propose such revisions by April 2013 and finalize the revisions by May 2014. New advanced wastewater treatment requirements are expected and may result in the installation of additional controls on certain of the facilities of Southern Company's subsidiaries, which could result in significant additional capital expenditures and compliance costs that could affect future unit retirement and replacement decisions. The impact of the revised guidelines will depend on the specific technology requirements of the final rule and, therefore, cannot be determined at this time.

Coal Combustion Byproducts

The traditional operating companies currently operate 22 electric generating plants with on-site coal combustion byproducts storage facilities. In addition to on-site storage, the traditional operating companies also sell a portion of their coal combustion byproducts to third parties for beneficial reuse. Historically, individual states have regulated coal combustion byproducts and the states in the Southern Company system's service territory each have their own regulatory parameters. Each traditional operating company has a routine and robust inspection program in place to ensure the integrity of its coal ash surface impoundments and compliance with applicable regulations.

The EPA continues to evaluate the regulatory program for coal combustion byproducts, including coal ash and gypsum, under federal solid and hazardous waste laws. In 2010, the EPA published a proposed rule that requested comments on two potential regulatory options for the management and disposal of coal combustion byproducts: regulation as a solid waste or regulation as if the materials technically constituted a hazardous waste. Adoption of either option could require closure of, or significant change to, existing storage facilities and construction of lined landfills, as well as additional waste management and groundwater monitoring requirements. Under both options, the EPA proposes to exempt the beneficial reuse of coal combustion byproducts from regulation; however, a hazardous or other designation indicative of heightened risk could limit or eliminate beneficial reuse options. Environmental groups and other parties have filed lawsuits in the U.S. District Court for the District of Columbia seeking to require the EPA to complete its rulemaking process and issue final regulations pertaining to the regulation of coal combustion byproducts.

While the ultimate outcome of this matter cannot be determined at this time and will depend on the final form of any rules adopted and the outcome of any legal challenges, additional regulation of coal combustion byproducts could have a material

impact on the generation, management, beneficial use, and disposal of such byproducts. Any material changes are likely to result in substantial additional compliance, operational, and capital costs that could affect future unit retirement and replacement decisions. Moreover, the traditional operating companies could incur additional material asset retirement obligations with respect to closing existing storage facilities. Southern Company's results of operations, cash flows, and financial condition could be significantly impacted if such costs are not recovered through regulated rates. Further, higher costs that are recovered through regulated rates could contribute to reduced demand for electricity, which could negatively impact results of operations, cash flows, and financial condition.

Environmental Remediation

The Southern Company system must comply with other environmental laws and regulations that cover the handling and disposal of waste and releases of hazardous substances. Under these various laws and regulations, the Southern Company system could incur substantial costs to clean up properties. The traditional operating companies conduct studies to determine the extent of any required cleanup and have recognized in their respective financial statements the costs to clean up known impacted sites. Amounts for cleanup and ongoing monitoring costs were not material for any year presented. The traditional operating companies have each received authority from their respective state PSCs to recover approved environmental compliance costs through regulatory mechanisms. These rates are adjusted annually or as necessary within limits approved by the state PSCs. The traditional operating companies may be liable for some or all required cleanup costs for additional sites that may require environmental remediation. See Note 3 to the financial statements under "Environmental Matters – Environmental Remediation" for additional information.

Global Climate Issues

The EPA currently regulates greenhouse gases under the Prevention of Significant Deterioration and Title V operating permit programs of the Clean Air Act. In addition, over the past several years, the U.S. Congress has considered many proposals to reduce greenhouse gas emissions, mandate renewable or clean energy, and impose energy efficiency standards. Such proposals are expected to continue to be considered by the U.S. Congress. International climate change negotiations under the United Nations Framework Convention on Climate Change are also continuing.

On April 13, 2012, the EPA published proposed regulations to establish standards of performance for greenhouse gas emissions from new fossil fuel steam electric generating units. The EPA has also announced plans to develop federal guidelines for states to establish greenhouse gas emissions performance standards for existing sources. The impact of this rulemaking will depend on the scope and specific requirements of the final rule and the outcome of any legal challenges and, therefore, cannot be determined at this time.

Although the outcome of federal, state, and international initiatives cannot be determined at this time, additional restrictions on the Southern Company system's greenhouse gas emissions or requirements relating to renewable energy or energy efficiency at the federal or state level could result in significant additional compliance costs, including capital expenditures. These costs could affect future unit retirement and replacement decisions and could result in the retirement of a significant number of coal-fired generating units. Also, additional compliance costs and costs related to unit retirements could affect results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates or through PPAs. Further, higher costs that are recovered through regulated rates could contribute to reduced demand for electricity, which could negatively impact results of operations, cash flows, and financial condition.

The EPA's greenhouse gas reporting rule requires annual reporting of carbon dioxide equivalent emissions in metric tons for a company's operational control of facilities. Based on ownership or financial control of facilities, the Southern Company system's 2011 greenhouse gas emissions were approximately 125 million metric tons of carbon dioxide equivalent. The preliminary estimate of the Southern Company system's 2012 greenhouse gas emissions on the same basis is approximately 98 million metric tons of carbon dioxide equivalent. The level of greenhouse gas emissions from year to year will depend on the level of generation and mix of fuel sources, which is determined primarily by demand, the unit cost of fuel consumed, and the availability of generating units.

PSC Matters

Alabama Power

Retail Rate Adjustments

In July 2011, the Alabama PSC issued an order to eliminate a tax-related adjustment under Alabama Power's rate structure effective with October 2011 billings. The elimination of this adjustment resulted in additional revenues of approximately $31 million for 2011. In accordance with the order, Alabama Power made additional accruals to the NDR in the fourth quarter 2011 of

an amount equal to such additional 2011 revenues. The NDR was impacted as a result of operations and maintenance expenses incurred in connection with the April 2011 storms in Alabama. See "Natural Disaster Reserve" below for additional information. The elimination of this adjustment resulted in additional revenues of approximately $106 million for 2012.

Rate RSE

Alabama Power operates under a rate stabilization and equalization plan (Rate RSE) approved by the Alabama PSC. Alabama Power's Rate RSE adjustments are based on forward-looking information for the applicable upcoming calendar year. Rate adjustments for any two-year period, when averaged together, cannot exceed 4.0% and any annual adjustment is limited to 5.0%. Retail rates remain unchanged when the retail return on common equity (ROE) is projected to be between 13.0% and 14.5%. If Alabama Power's actual retail ROE is above the allowed equity return range, customer refunds will be required; however, there is no provision for additional customer billings should the actual retail ROE fall below the allowed equity return range.

In 2011 and 2012, retail rates under Rate RSE remained unchanged from 2010. On November 30, 2012, Alabama Power made its Rate RSE submission to the Alabama PSC of projected data for calendar year 2013; projected earnings were within the specified return range, and, therefore, retail rates under Rate RSE remained unchanged for 2013. Under the terms of Rate RSE, the maximum possible increase for 2014 is 5.00%. However, Alabama Power is working with the Alabama PSC to develop a plan that will potentially preclude the need for a Rate RSE increase in 2014. The ultimate outcome of this matter cannot be determined at this time.

Rate CNP

Alabama Power's retail rates, approved by the Alabama PSC, provide for adjustments to recognize the placing of new generating facilities into retail service under rate certificated new plant (Rate CNP). Alabama Power may also recover retail costs associated with certificated PPAs under rate certificated new plant (Rate CNP PPA). Effective April 2011, Rate CNP PPA was reduced by approximately $5 million annually. On March 6, 2012, the Alabama PSC issued a consent order that Alabama Power leave in effect the current Rate CNP PPA factor for billings for the period April 1, 2012 through March 31, 2013. It is anticipated that no adjustment will be made to Rate CNP PPA in 2013. As of December 31, 2012, Alabama Power had an under recovered certificated PPA balance of $9 million, $7 million of which is included in deferred under recovered regulatory clause revenues and $2 million of which is included in under recovered regulatory clause revenues in the balance sheet.

On September 17, 2012, the Alabama PSC approved and certificated a PPA for the purchase of approximately 200 MWs of the approximately 400 MWs of energy from wind-powered generating facilities and all associated environmental attributes, including renewable energy credits. The terms of this PPA and a previously approved and certificated PPA permit Alabama Power to use the energy and retire the associated environmental attributes in service of its customers or to sell environmental attributes, separately or bundled with energy, to third parties. Approximately 200 MWs of energy from wind-powered generating facilities was operational in December 2012.

Rate CNP Environmental also allows for the recovery of Alabama Power's retail costs associated with environmental laws, regulations, or other such mandates. Rate CNP Environmental is based on forward-looking information and provides for the recovery of these costs pursuant to a factor that is calculated annually. Environmental costs to be recovered include operations and maintenance expenses, depreciation, and a return on certain invested capital. There was no adjustment to Rate CNP Environmental to recover environmental costs in 2011 or 2012. On November 26, 2012, Alabama Power submitted calculations associated with its cost of complying with environmental mandates, as provided under Rate CNP Environmental. The filing reflected a projected unrecovered retail revenue requirement for environmental compliance of less than $1 million, which is to be recovered in the billing months of January 2013 through December 2013. On December 4, 2012, the Alabama PSC issued a consent order that Alabama Power leave in effect for 2013 the factors associated with Alabama Power's environmental compliance costs for the year 2012. Any unrecovered amounts associated with 2013 will be reflected in the 2014 filing. As of December 31, 2012, Alabama Power had an under recovered environmental clause balance of $21 million which is included in under recovered regulatory clause revenues in the balance sheet.

Environmental Accounting Order

Proposed and final environmental regulations could result in significant additional compliance costs that could affect future unit retirement and replacement decisions. In September 2011, the Alabama PSC approved an order allowing for the establishment of a regulatory asset to record the unrecovered investment costs associated with any such decisions, including the unrecovered plant asset balance and the unrecovered costs associated with site removal and closure. These costs would be amortized over the affected unit's remaining useful life, as established prior to the decision regarding early retirement. See "Environmental Matters – Environmental Statutes and Regulations" herein for additional information regarding environmental regulations.

Compliance and Pension Cost Accounting Order

On November 6, 2012, the Alabama PSC approved an accounting order for certain compliance-related operation and maintenance expenditures for the years 2013 through 2017, as well as the incremental increase in operation expense related to pension cost for 2013. Under the accounting order, expenses from January 2013 through December 2017 related to compliance with standards addressing Critical Infrastructure Protection issued by the North American Electric Reliability Corporation and cyber security requirements issued by the Nuclear Regulatory Commission (NRC) will be deferred to a regulatory asset account and amortized over a three-year period beginning in January 2015. Expenses from January 2013 through December 2017 related to compliance with NRC guidance addressing the readiness at nuclear facilities within the U.S., as prompted by the earthquake and tsunami that struck Japan in March 2011, also will be deferred as a regulatory asset and recovered over the same amortization period. The compliance-related expenses to be afforded regulatory asset treatment over the five-year period are currently estimated to be approximately $43 million. See "Other Matters" herein for information regarding the NRC's guidance issued as a result of the earthquake and tsunami that struck Japan in 2011. In addition, the accounting order authorizes Alabama Power to defer an incremental increase in its pension cost for 2013. That increased pension cost is estimated to be approximately $17 million. During 2013, the actual incremental increase will be deferred to a regulatory asset account and will be amortized over a three-year period beginning in January 2015. Pursuant to the accounting order, Alabama Power has the ability to accelerate the amortization of the regulatory assets.

Natural Disaster Reserve

Based on an order from the Alabama PSC, Alabama Power maintains a reserve for operations and maintenance expenses to cover the cost of damages from major storms to its transmission and distribution facilities. The order approves a separate monthly Rate Natural Disaster Reserve (Rate NDR) charge to customers consisting of two components. The first component is intended to establish and maintain a reserve balance for future storms and is an on-going part of customer billing. The second component of the Rate NDR charge is intended to allow recovery of any existing deferred storm-related operations and maintenance costs and any future reserve deficits over a 24-month period. The Alabama PSC order gives Alabama Power authority to record a deficit balance in the NDR when costs of storm damage exceed any established reserve balance. Alabama Power has the authority, based on an order from the Alabama PSC, to accrue certain additional amounts as circumstances warrant. The order allows for reliability-related expenditures to be charged against the additional accruals when the NDR balance exceeds $75 million. Alabama Power may designate a portion of the NDR to reliability-related expenditures as a part of an annual budget process for the following year or during the current year for identified unbudgeted reliability-related expenditures that are incurred. Accruals that have not been designated can be used to offset storm charges. Additional accruals to the NDR will enhance Alabama Power's ability to deal with the financial effects of future natural disasters, promote system reliability, and offset costs retail customers would otherwise bear.

As revenue from the Rate NDR charge is recognized, an equal amount of operations and maintenance expenses related to the NDR will also be recognized. As a result, the Rate NDR charge will not have an effect on net income but will impact operating cash flows.

During the first half of 2011, multiple storms caused varying degrees of damage to Alabama Power's transmission and distribution facilities. The most significant storms occurred in April 2011, causing over 400,000 of Alabama Power's 1.4 million customers to be without electrical service. The cost of repairing the damage to facilities and restoring electrical service to customers as a result of these storms was $42 million for operations and maintenance expenses and $161 million for capital-related expenditures.

In accordance with the order that was issued by the Alabama PSC in July 2011 to eliminate a tax-related adjustment under Alabama Power's rate structure that resulted in additional revenues, Alabama Power made additional accruals to the NDR in the fourth quarter 2011 of an amount equal to the additional 2011 revenues, which were approximately $31 million.

The accumulated balances in the NDR for the years ended December 31, 2012 and December 31, 2011 were approximately $103 million and $110 million, respectively. Any accruals to the NDR are included in the balance sheets under other regulatory liabilities, deferred and are reflected as other operations and maintenance expenses in the statements of income.

Nuclear Outage Accounting Order

In 2010, the Alabama PSC approved a change to the nuclear maintenance outage accounting process associated with routine refueling activities. Previously, Alabama Power accrued nuclear outage operations and maintenance expenses for the two units at Plant Farley during the 18-month cycle for the outages. In accordance with the 2010 order, nuclear outage expenses are deferred when the charges actually occur and then amortized over the subsequent 18-month period.

The initial result of implementation of the accounting order was that no nuclear maintenance outage expenses were recognized from January 2011 through December 2011, which decreased nuclear outage operations and maintenance expenses in 2011 from 2010 by approximately $50 million. During the fall of 2011, approximately $38 million of actual nuclear outage expenses associated with one unit at Plant Farley was deferred to a regulatory asset account; beginning in January 2012, these deferred costs are being amortized to nuclear operations and maintenance expenses over an 18-month period. During the spring of 2012, approximately $31 million of actual nuclear outage expenses associated with the second unit at Plant Farley was deferred to a regulatory asset account; beginning in July 2012, these deferred costs are being amortized to nuclear operations and maintenance expenses over an 18-month period. Alabama Power will continue the pattern of deferral of nuclear outage expenses as incurred and the recognition of expenses over a subsequent 18-month period pursuant to the existing order.

Georgia Power

Rate Plans

The economic recession significantly reduced Georgia Power's revenues upon which retail rates were set by the Georgia PSC for 2008 through 2010 (2007 Retail Rate Plan). In 2009, despite stringent efforts to reduce expenses, Georgia Power's projected retail ROE for both 2009 and 2010 was below 10.25%. However, in lieu of a full base rate case to increase customer rates as allowed under the 2007 Retail Rate Plan, in 2009, the Georgia PSC approved Georgia Power's request for an accounting order. Under the terms of the accounting order, Georgia Power could amortize up to $108 million of the regulatory liability related to other cost of removal obligations in 2009 and up to $216 million in 2010, limited to the amount needed to earn no more than a 9.75% and 10.15% retail ROE in 2009 and 2010, respectively. For the years ended December 31, 2009 and 2010, Georgia Power amortized $41 million and $174 million, respectively, of the regulatory liability related to other cost of removal obligations.

In 2010, the Georgia PSC approved the 2010 ARP, which became effective January 1, 2011. The terms of the 2010 ARP reflect a settlement agreement among Georgia Power, the Georgia PSC Public Interest Advocacy Staff, and eight other intervenors. Under the terms of the 2010 ARP, Georgia Power is amortizing approximately $92 million of its remaining regulatory liability related to other cost of removal obligations over the three years ending December 31, 2013.

Also under the terms of the 2010 ARP, effective January 1, 2011, Georgia Power increased its (1) traditional base tariff rates by approximately $347 million; (2) Demand-Side Management (DSM) tariff rates by approximately $31 million; (3) environmental compliance cost recovery tariff rate by approximately $168 million; and (4) Municipal Franchise Fee (MFF) tariff rate by approximately $16 million, for a total increase in base revenues of approximately $562 million.

Under the 2010 ARP, the following additional base rate adjustments have been made to Georgia Power's tariffs in 2012 and 2013:

- Effective January 1, 2012 and 2013, the DSM tariffs increased by $17 million and $14 million, respectively;
- Effective April 1, 2012 and January 1, 2013, the traditional base tariffs increased by an estimated $122 million and $58 million, respectively, to recover the revenue requirements for Plant McDonough-Atkinson Units 4, 5, and 6 for the period through December 31, 2013; and
- The MFF tariff increased consistently with the adjustments above, as well as those related to the interim fuel rider and NCCR tariff adjustments described in Note 3 to the financial statements under "Retail Regulatory Matters – Georgia Power – Fuel Cost Recovery" and "Retail Regulatory Matters – Georgia Power – Nuclear Construction."

Under the 2010 ARP, Georgia Power's allowed retail ROE is set at 11.15%, and earnings will be evaluated against a retail ROE range of 10.25% to 12.25%. Two-thirds of any earnings above 12.25% will be directly refunded to customers, with the remaining one-third retained by Georgia Power. There were no refunds related to earnings for 2011 or 2012. Georgia Power is required to file a general base rate case by July 1, 2013, in response to which the Georgia PSC would be expected to determine whether the 2010 ARP should be continued, modified, or discontinued.

Integrated Resource Plans

See "Environmental Matters – Environmental Statutes and Regulations – Air Quality," "– Water Quality," and "– Coal Combustion Byproducts" and "Rate Plans" herein for additional information regarding proposed and final EPA rules and regulations, including the MATS rule for coal- and oil-fired electric utility steam generating units, revisions to effluent guidelines for steam electric power plants, and additional regulation of coal combustion byproducts; the State of Georgia's Multi-Pollutant Rule; Georgia Power's analysis of the potential costs and benefits of installing the required controls on its fossil generating units in light of these regulations; and the 2010 ARP.

On March 20, 2012, the Georgia PSC approved Georgia Power's request to decertify and retire Plant Branch Units 1 and 2 as of December 31, 2013 and October 31, 2013, the compliance dates for the respective units under the Georgia Multi-Pollutant Rule, and an oil-fired unit at Plant Mitchell as of March 26, 2012, as requested in the 2011 Integrated Resource Plan (IRP). The Georgia PSC also approved three PPAs totaling 998 MWs with Southern Power for capacity and energy that will commence in 2015 and end in 2030. On November 21, 2012, the FERC accepted the PPAs.

Separately, on March 20, 2012, the Georgia PSC certified 495 MWs of wholesale capacity to be returned to retail service in 2015 and 2016 under a 2010 agreement, subject to the decertification of any related generating units including 243 MWs of the 16 units described below.

On January 31, 2013, Georgia Power filed its triennial IRP (2013 IRP). The filing included Georgia Power's request to decertify 16 coal- and oil-fired units totaling 2,093 MWs. Several factors, including the cost to comply with existing and future environmental regulations, recent and forecasted economic conditions, and lower natural gas prices, contributed to the decision to close these units.

Georgia Power requested the decertification of Plant Boulevard Units 2 and 3 (28 MWs) upon approval of the 2013 IRP and the decertification of Plant Bowen Unit 6 (32 MWs) by April 16, 2013. Plant Branch Units 3 and 4 (1,016 MWs), Plant Yates Units 1 through 5 (579 MWs), and Plant McManus Units 1 and 2 (122 MWs) will be retired by April 16, 2015, the compliance date of the MATS rule. Georgia Power has also requested a revision to the decertification date of Plant Branch Unit 1 from December 31, 2013 to April 16, 2015. To allow for necessary transmission reliability improvements, Georgia Power expects to seek a one-year extension of the MATS rule compliance date for Plant Kraft Units 1 through 4 (316 MWs) and to retire these units by April 16, 2016.

The filing also included Georgia Power's request to switch the primary fuel source for Plant Yates Units 6 and 7 from coal to natural gas. Additionally, Georgia Power plans to switch the primary fuel source for Plant McIntosh Unit 1 from Central Appalachian coal to Powder River Basin (PRB) coal following further evaluation, including a successful test burn of the PRB fuel.

Under the terms of the 2010 ARP, any costs associated with changes to Georgia Power's approved environmental operating or capital budgets resulting from new or revised environmental regulations through 2013 that are approved by the Georgia PSC in connection with an updated IRP will be deferred as a regulatory asset to be recovered over a time period deemed appropriate by the Georgia PSC. In connection with the retirement decisions, Georgia Power reclassified the retail portion of the net carrying value of Plant Branch Units 1 through 4 from plant in service, net of depreciation, to other utility plant, net. Georgia Power is continuing to depreciate these units using the current composite straight-line rates previously approved by the Georgia PSC. Upon actual retirement, the Georgia PSC approved the continued deferral and amortization of the remaining net carrying values for Plant Branch Units 1 and 2 in its order for the 2011 IRP and Georgia Power has requested similar treatment for Plant Branch Units 3 and 4 in the 2013 IRP. Georgia Power also reclassified the CWIP balances totaling $65 million related to environmental controls for Plant Branch Units 1 through 4 and Plant Yates Units 6 and 7 that will not be completed as a result of the retirement decisions to regulatory assets and ceased accruing AFUDC. The Georgia PSC approved a three-year amortization period beginning January 2014 for the $13 million balance relating to Plant Branch Units 1 and 2 in its order for the 2011 IRP and Georgia Power has requested similar treatment for the balances related to Plant Branch Units 3 and 4 and Plant Yates Units 6 and 7 in the 2013 IRP. Georgia Power has also requested that the Georgia PSC approve the deferral of the costs associated with material and supplies remaining at the unit retirement dates to a regulatory asset, to be amortized over a time period deemed appropriate by the Georgia PSC. As a result of this regulatory treatment, the decertification of these units is not expected to have a material impact on Southern Company's financial statements. The Georgia PSC is scheduled to vote on the 2013 IRP by July 2013.

Storm Damage Recovery

Georgia Power defers and recovers certain costs related to damages from major storms as mandated by the Georgia PSC. As of December 31, 2012, the balance in the regulatory asset related to storm damage was $38 million. As a result of this regulatory treatment, the costs related to storms are generally not expected to have a material impact on Southern Company's financial statements.

Fuel Cost Recovery

The traditional operating companies each have established fuel cost recovery rates approved by their respective state PSCs. The traditional operating companies have experienced lower pricing for natural gas resulting in an increase in natural gas generation and a decrease in coal generation, which is currently more costly. The lower cost of natural gas has resulted in total over recovered fuel costs in the balance sheets of Georgia Power, Gulf Power, and Mississippi Power of approximately $303 million at December 31, 2012. Total under recovered fuel costs were approximately $4 million in the balance sheet of Alabama Power at December 31, 2012. At December 31, 2011, total under recovered fuel costs in the balance sheets of Alabama Power and Georgia Power were approximately $169 million, and total over recovered fuel costs in the balance sheets of Gulf Power and Mississippi Power were approximately $52 million.

Fuel cost recovery revenues are adjusted for differences in actual recoverable fuel costs and amounts billed in current regulated rates. Accordingly, changes in the billing factor will not have a significant effect on Southern Company's revenues or net income, but will affect annual cash flow. The traditional operating companies continuously monitor the under or over recovered fuel cost balances.

See Note 1 to the financial statements under "Revenues" and Note 3 to the financial statements under "Retail Regulatory Matters – Alabama Power – Energy Cost Recovery" and "Retail Regulatory Matters – Georgia Power – Fuel Cost Recovery" for additional information.

Income Tax Matters

Bonus Depreciation

In 2010, the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010 (Tax Relief Act) was signed into law. Major tax incentives in the Tax Relief Act include 100% bonus depreciation for property placed in service after September 8, 2010 and through 2011 (and for certain long-term production-period projects placed in service in 2012) and 50% bonus depreciation for property placed in service in 2012 (and for certain long-term production-period projects to be placed in service in 2013), which will have a positive impact on the future cash flows of Southern Company through 2013.

On January 2, 2013, the American Taxpayer Relief Act of 2012 (ATRA) was signed into law. The ATRA retroactively extended several tax credits through 2013 and extended 50% bonus depreciation for property to be placed in service in 2013 (and for certain long-term production-period projects to be placed in service in 2014). The extension of 50% bonus depreciation will have a positive impact on the future cash flows of Southern Company through 2014.

Due to the significant amount of estimated bonus depreciation for 2013, a portion of Southern Company's tax credit utilization will be deferred. Consequently, Southern Company's positive cash flow benefit is estimated to be between $275 million and $310 million in 2013.

Construction Program

The subsidiary companies of Southern Company are engaged in continuous construction programs to accommodate existing and estimated future loads on their respective systems. The Southern Company system intends to continue its strategy of developing and constructing new generating facilities, including the ongoing construction of solar units at Southern Power, Plant Vogtle Units 3 and 4 at Georgia Power, and the Kemper IGCC at Mississippi Power, as well as adding or changing fuel sources for certain existing units, adding environmental control equipment, and expanding the transmission and distribution systems. For the traditional operating companies, major generation construction projects are subject to state PSC approvals in order to be included in retail rates. While Southern Power generally constructs and acquires generation assets covered by long-term PPAs, any uncontracted capacity could negatively affect future earnings. The construction programs of the traditional operating companies and Southern Power are currently estimated to include an investment of approximately $5.5 billion, $5.8 billion, and $5.2 billion for 2013, 2014, and 2015, respectively.

The two largest construction projects currently underway in the Southern Company system are Plant Vogtle Units 3 and 4 (45.7% ownership interest in two units, each with approximately 1,100 MWs) and the construction of the Kemper IGCC (for a total of 582 MWs). See Note 3 to the financial statements under "Retail Regulatory Matters – Georgia Power – Nuclear Construction" and "Integrated Coal Gasification Combined Cycle" for additional information.

See RISK FACTORS of Southern Company in Item 1A of the Form 10-K for a discussion of certain risks associated with the construction program in general and certain risks associated with the licensing, construction, and operation of nuclear generating units in particular, including potential impacts that could result from a major incident at a nuclear facility anywhere in the world. The ultimate outcome of these events cannot be determined at this time.

Investments in Leveraged Leases

Southern Company has several leveraged lease agreements, with original terms ranging up to 45 years, which relate to international and domestic energy generation, distribution, and transportation assets. Southern Company receives federal income tax deductions for depreciation and amortization, as well as interest on long-term debt related to these investments. Southern Company reviews all important lease assumptions at least annually, or more frequently if events or changes in circumstances indicate that a change in assumptions has occurred or may occur. These assumptions include the effective tax rate, the residual value, the credit quality of the lessees, and the timing of expected tax cash flows. See Note 1 to the financial statements under "Leveraged Leases" for additional information.

The recent financial and operational performance of one of Southern Company's lessees and the associated generation assets has raised potential concerns on the part of Southern Company as to the credit quality of the lessee and the residual value of the assets. Due to the poor performance of the generation assets and the uncertainties surrounding the receipt of future rent payments and its ability to successfully restructure the project, Southern Company placed the lease on nonaccrual status whereby, effective July 2012, income associated with this investment is not recognized in the financial statements. The lessee was unable to pay its December 2012 semiannual rent payment in full. To avoid a default on the lease and the project's nonrecourse debt, the due date for the December 2012 rent payment and the associated debt payment was extended to March 6, 2013 while restructuring negotiations continued between the parties to the transaction. The aim of the negotiations is to restructure the debt payments and the related rental payments to allow additional capital investment in the project to be made by Southern Company to improve the operation of the generation assets. Such operational improvements are projected to provide sufficient cash flows for Southern Company to realize the full amount of its investment in the lease receivable. The parties to the lease have reached general agreement as to the restructuring and Southern Company believes that it is likely that it will be able to complete the restructuring prior to the end of the first quarter 2013. If the restructuring is successfully completed, Southern Company will be required to record a reduction in leveraged lease income of up to approximately $17 million at that time. However, if the restructuring is unsuccessful and the project is ultimately abandoned, the potential impairment loss that would be incurred is approximately $90 million on an after-tax basis. The ultimate outcome of this matter cannot be determined at this time.

Other Matters

Southern Company and its subsidiaries are involved in various other matters being litigated and regulatory matters that could affect future earnings. In addition, Southern Company and its subsidiaries are subject to certain claims and legal actions arising in the ordinary course of business. The business activities of Southern Company's subsidiaries are subject to extensive governmental regulation related to public health and the environment, such as regulation of air emissions and water discharges. Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements, such as air quality and water standards, has increased generally throughout the U.S. In particular, personal injury, property damage, and other claims for damages alleged to have been caused by carbon dioxide and other emissions, coal combustion byproducts, and alleged exposure to hazardous materials, and/or requests for injunctive relief in connection with such matters, have become more frequent.

The ultimate outcome of such pending or potential litigation against Southern Company and its subsidiaries cannot be predicted at this time; however, for current proceedings not specifically reported herein or in Note 3 to the financial statements, management does not anticipate that the ultimate liabilities, if any, arising from such current proceedings would have a material effect on Southern Company's financial statements. See Note 3 to the financial statements for a discussion of various other contingencies, regulatory matters, and other matters being litigated which may affect future earnings potential.

In March 2011, a major earthquake and tsunami struck Japan and caused substantial damage to the nuclear generating units at the Fukushima Daiichi generating plant. The events in Japan have created uncertainties that may affect future costs for operating nuclear plants. Specifically, the NRC is performing additional operational and safety reviews of nuclear facilities in the U.S., which could potentially impact future operations and capital requirements. On March 12, 2012, the NRC issued three orders and a request for information based on the July 2011 NRC task force report recommendations that included, among other items, additional mitigation strategies for beyond-design-basis events, enhanced spent fuel pool instrumentation capabilities, hardened vents for certain classes of containment structures, including the one in use at Plant Hatch, site specific evaluations for seismic and flooding hazards, and various plant evaluations to ensure adequate coping capabilities during station blackout and other conditions. On August 29, 2012, the NRC staff issued the final interim staff guidance document, which offers acceptable approaches to meeting the requirements of the NRC's orders before the December 31, 2016 compliance deadline. The interim staff guidance is not mandatory, but licensees would be required to obtain NRC approval for taking an approach other than as outlined in the interim staff guidance. The final form and the resulting impact of any changes to safety requirements for nuclear reactors will be dependent on further review and action by the NRC and cannot be determined at this time; however, management

does not currently anticipate that the associated compliance costs would have a material impact on Southern Company's financial statements.

See RISK FACTORS of Southern Company in Item 1A of the Form 10-K for a discussion of certain risks associated with the licensing, construction, and operation of nuclear generating units, including potential impacts that could result from a major incident at a nuclear facility anywhere in the world. The ultimate outcome of these events cannot be determined at this time.

See "PSC Matters – Alabama Power – Compliance and Pension Cost Accounting Order" herein for additional information on Alabama Power's PSC approved accounting order, which allows the deferral of certain compliance-related operations and maintenance expenditures related to compliance with the NRC guidance.

ACCOUNTING POLICIES

Application of Critical Accounting Policies and Estimates

Southern Company prepares its consolidated financial statements in accordance with GAAP. Significant accounting policies are described in Note 1 to the financial statements. In the application of these policies, certain estimates are made that may have a material impact on Southern Company's results of operations and related disclosures. Different assumptions and measurements could produce estimates that are significantly different from those recorded in the financial statements. Senior management has reviewed and discussed the following critical accounting policies and estimates with the Audit Committee of Southern Company's Board of Directors.

Electric Utility Regulation

Southern Company's traditional operating companies, which comprised approximately 95% of Southern Company's total operating revenues for 2012, are subject to retail regulation by their respective state PSCs and wholesale regulation by the FERC. These regulatory agencies set the rates the traditional operating companies are permitted to charge customers based on allowable costs. As a result, the traditional operating companies apply accounting standards which require the financial statements to reflect the effects of rate regulation. Through the ratemaking process, the regulators may require the inclusion of costs or revenues in periods different than when they would be recognized by a non-regulated company. This treatment may result in the deferral of expenses and the recording of related regulatory assets based on anticipated future recovery through rates or the deferral of gains or creation of liabilities and the recording of related regulatory liabilities. The application of the accounting standards has a further effect on the Company's financial statements as a result of the estimates of allowable costs used in the ratemaking process. These estimates may differ from those actually incurred by the traditional operating companies; therefore, the accounting estimates inherent in specific costs such as depreciation, nuclear decommissioning, and pension and postretirement benefits have less of a direct impact on the Company's results of operations and financial condition than they would on a non-regulated company.

As reflected in Note 1 to the financial statements, significant regulatory assets and liabilities have been recorded. Management reviews the ultimate recoverability of these regulatory assets and any requirement to refund these regulatory liabilities based on applicable regulatory guidelines and GAAP. However, adverse legislative, judicial, or regulatory actions could materially impact the amounts of such regulatory assets and liabilities and could adversely impact the Company's financial statements.

Contingent Obligations

Southern Company and its subsidiaries are subject to a number of federal and state laws and regulations, as well as other factors and conditions that subject them to environmental, litigation, income tax, and other risks. See FUTURE EARNINGS POTENTIAL herein and Note 3 to the financial statements for more information regarding certain of these contingencies. Southern Company periodically evaluates its exposure to such risks and, in accordance with GAAP, records reserves for those matters where a non-tax-related loss is considered probable and reasonably estimable and records a tax asset or liability if it is more likely than not that a tax position will be sustained. The adequacy of reserves can be significantly affected by external events or conditions that can be unpredictable; thus, the ultimate outcome of such matters could materially affect Southern Company's financial statements.

Pension and Other Postretirement Benefits

Southern Company's calculation of pension and other postretirement benefits expense is dependent on a number of assumptions. These assumptions include discount rates, healthcare cost trend rates, expected long-term return on plan assets, mortality rates, expected salary and wage increases, and other factors. Components of pension and other postretirement benefits expense include interest and service cost on the pension and other postretirement benefit plans, expected return on plan assets, and amortization of certain unrecognized costs and obligations. Actual results that differ from the assumptions utilized are accumulated and amortized

over future periods and, therefore, generally affect recognized expense and the recorded obligation in future periods. While the Company believes that the assumptions used are appropriate, differences in actual experience or significant changes in assumptions would affect its pension and other postretirement benefits costs and obligations.

Key elements in determining Southern Company's pension and other postretirement benefit expense in accordance with GAAP are the expected long-term return on plan assets and the discount rate used to measure the benefit plan obligations and the periodic benefit plan expense for future periods. The expected long-term return on postretirement benefit plan assets is based on Southern Company's investment strategy, historical experience, and expectations for long-term rates of return that consider external actuarial advice. Southern Company determines the long-term return on plan assets by applying the long-term rate of expected returns on various asset classes to Southern Company's target asset allocation. Southern Company discounts the future cash flows related to its postretirement benefit plans using a single-point discount rate developed from the weighted average of market-observed yields for high quality fixed income securities with maturities that correspond to expected benefit payments.

The following table illustrates the sensitivity to changes in Southern Company's long-term assumptions with respect to the assumed discount rate, the assumed salaries, and the assumed long-term rate of return on plan assets:

Change in Assumption	Increase/ (Decrease) in Total Benefit Expense for 2013	Increase/ (Decrease) in Projected Obligation for Pension Plan at December 31, 2012	Increase/(Decrease) in Projected Obligation for Other Postretirement Benefit Plans at December 31, 2012
		(in millions)	
25 basis point change in discount rate	$32/$(30)	$346/$(327)	$72/$(68)
25 basis point change in salaries	$17/$(16)	$93/$(89)	$-/$-
25 basis point change in long-term return on plan assets	$21/$(21)	N/A	N/A

N/A – Not applicable

FINANCIAL CONDITION AND LIQUIDITY

Overview

Southern Company's financial condition remained stable at December 31, 2012. Southern Company's cash requirements primarily consist of funding ongoing operations, common stock dividends, capital expenditures, and debt maturities. Capital expenditures and other investing activities include investments to meet projected long-term demand requirements, to comply with environmental regulations, and for restoration following major storms. Operating cash flows provide a substantial portion of the Southern Company system's cash needs. For the three-year period from 2013 through 2015, Southern Company's projected common stock dividends, capital expenditures, and debt maturities are expected to exceed operating cash flows. Projected capital expenditures in that period include investments to build new generation facilities, to add environmental equipment for existing generating units, and to expand and improve transmission and distribution facilities. Southern Company plans to finance future cash needs in excess of its operating cash flows primarily through debt and equity issuances. Southern Company intends to continue to monitor its access to short-term and long-term capital markets as well as its bank credit arrangements to meet future capital and liquidity needs. See "Sources of Capital," "Financing Activities," and "Capital Requirements and Contractual Obligations" herein for additional information.

Southern Company's investments in the qualified pension plan and the nuclear decommissioning trust funds increased in value as of December 31, 2012 as compared to December 31, 2011. In December 2012, certain of the traditional operating companies and other subsidiaries contributed $445 million to the qualified pension plan.

Net cash provided from operating activities in 2012 totaled $4.9 billion, a decrease of $1.0 billion from the corresponding period in 2011. Significant changes in operating cash flow for 2012 as compared to the corresponding period in 2011 include an increase in fossil fuel stock and contributions to the qualified pension plan. Net cash provided from operating activities in 2011 totaled $5.9 billion, an increase of $1.9 billion from the corresponding period in 2010. Significant changes in operating cash flow for 2011 as compared to the corresponding period in 2010 include an increase in net income, a contribution to the qualified pension plan in 2010, and a decrease in taxes paid due to bonus depreciation.

Net cash used for investing activities in 2012, 2011, and 2010 totaled $5.2 billion, $4.2 billion, and $4.3 billion, respectively. The cash used for investing activities for each of these years was primarily for property additions to utility plant.

Net cash used for financing activities totaled $417 million in 2012 due to redemptions of long-term debt, the repurchase of common stock, and payments of common stock dividends, partially offset by issuances of long-term debt. Net cash used for financing activities totaled $852 million in 2011 due to a reduction of short-term debt outstanding and redemptions of long-term debt. Net cash provided from financing activities totaled $22 million in 2010 primarily due to long-term debt issuances offset mostly by long-term debt redemptions. Fluctuations in cash flow from financing activities vary from year to year based on capital needs and the maturity or redemption of securities.

Significant balance sheet changes in 2012 include an increase of $3.4 billion in total property, plant, and equipment for the installation of equipment to comply with environmental standards and construction of generation, transmission, and distribution facilities. Other significant changes include a decrease in cash of $687 million primarily due to a decrease in temporary cash investments, an increase in deferred income taxes of $1.1 billion due to bonus depreciation, and $719 million of additional equity.

At the end of 2012, the closing price of Southern Company's common stock was $42.81 per share, compared with a book value of $21.09 per share. The market-to-book value ratio was 203% at the end of 2012, compared with 228% at year-end 2011.

Sources of Capital

Southern Company intends to meet its future capital needs through internal cash flow and external security issuances. Equity capital can be provided from any combination of the Company's stock plans, private placements, or public offerings. The amount and timing of additional equity capital to be raised in 2013, as well as in subsequent years, will be contingent on Southern Company's investment opportunities.

Except as described herein, the traditional operating companies and Southern Power plan to obtain the funds required for construction and other purposes from sources similar to those used in the past, which were primarily from operating cash flows, security issuances, term loans, short-term borrowings, and equity contributions from Southern Company. However, the amount, type, and timing of any future financings, if needed, will depend upon prevailing market conditions, regulatory approval, and other factors.

In 2010, Georgia Power reached an agreement with the U.S. Department of Energy (DOE) to accept terms for a conditional commitment for federal loan guarantees that would apply to future Georgia Power borrowings related to the construction of Plant Vogtle Units 3 and 4. Any borrowings guaranteed by the DOE would be full recourse to Georgia Power and secured by a first priority lien on Georgia Power's 45.7% undivided ownership interest in Plant Vogtle Units 3 and 4. Total guaranteed borrowings would not exceed the lesser of 70% of eligible project costs, or approximately $3.46 billion, and are expected to be funded by the Federal Financing Bank. Final approval and issuance of loan guarantees by the DOE are subject to negotiation of definitive agreements, completion of due diligence by the DOE, receipt of any necessary regulatory approvals, and satisfaction of other conditions. In the event that the DOE does not issue a loan guarantee or Georgia Power determines that the final terms and conditions of the loan guarantee by the DOE are not in the best interest of its customers, Georgia Power expects to finance the construction of Plant Vogtle Units 3 and 4 through traditional capital markets financings. There can be no assurance that the DOE will issue loan guarantees for Georgia Power. The conditional commitment will expire on June 30, 2013, unless further extended by the DOE. See Note 3 to the financial statements under "Retail Regulatory Matters – Georgia Power – Nuclear Construction" for more information on Plant Vogtle Units 3 and 4.

In addition, Mississippi Power received DOE Clean Coal Power Initiative Round 2 (CCPI2) grant funds of $245 million that were used for the construction of the Kemper IGCC. An additional $25 million in CCPI2 grant funds is expected to be received for the initial operation of the Kemper IGCC. On January 29, 2013, Mississippi Power withdrew its application for federal loan guarantees related to the Kemper IGCC. See Note 3 to the financial statements under "Integrated Coal Gasification Combined Cycle" for information regarding legislation related to the securitization of certain costs of the Kemper IGCC.

The issuance of securities by the traditional operating companies is generally subject to the approval of the applicable state PSC. The issuance of all securities by Mississippi Power and Southern Power and short-term securities by Georgia Power is generally subject to regulatory approval by the FERC. Additionally, with respect to the public offering of securities, Southern Company and certain of its subsidiaries file registration statements with the Securities and Exchange Commission (SEC) under the Securities Act of 1933, as amended (1933 Act). The amounts of securities authorized by the appropriate regulatory authorities, as well as the securities registered under the 1933 Act, are continuously monitored and appropriate filings are made to ensure flexibility in the capital markets.

Southern Company, each traditional operating company, and Southern Power obtain financing separately without credit support from any affiliate. See Note 6 to the financial statements under "Bank Credit Arrangements" for additional information. The Southern Company system does not maintain a centralized cash or money pool. Therefore, funds of each company are not commingled with funds of any other company in the Southern Company system.

Southern Company's current liabilities frequently exceed current assets because of the continued use of short-term debt as a funding source to meet scheduled maturities of long-term debt, as well as cash needs, which can fluctuate significantly due to the seasonality of the business of the Southern Company system. To meet short-term cash needs and contingencies, Southern Company has substantial cash flow from operating activities and access to capital markets, including commercial paper programs which are backed by bank credit facilities.

At December 31, 2012, Southern Company and its subsidiaries had approximately $628 million of cash and cash equivalents. Committed credit arrangements with banks at December 31, 2012 were as follows:

	Expires[a]					Executable Term Loans		Due Within One Year	
Company	2013	2014	2016	Total	Unused	One Year	Two Years	Term Out	No Term Out
		(in millions)		(in millions)		(in millions)		(in millions)	
Southern Company	$ —	$ —	$ 1,000	$ 1,000	$ 1,000	$ —	$ —	$ —	$ —
Alabama Power	158	350	800	1,308	1,308	56	—	56	102
Georgia Power	—	250	1,500	1,750	1,740	—	—	—	—
Gulf Power	80	195	—	275	275	45	—	45	35
Mississippi Power	135	165	—	300	300	25	40	65	70
Southern Power	—	—	500	500	500	—	—	—	—
Other	50	—	—	50	50	25	—	25	25
Total	$ 423	$ 960	$ 3,800	$ 5,183	$ 5,173	$ 151	$ 40	$ 191	$ 232

(a) No credit arrangements expire in 2015.

See Note 6 to the financial statements under "Bank Credit Arrangements" for additional information.

Most of these arrangements contain covenants that limit debt levels and contain cross default provisions that are restricted only to the indebtedness of the individual company. Southern Company and its subsidiaries are currently in compliance with all such covenants.

A portion of the unused credit with banks is allocated to provide liquidity support to the traditional operating companies' variable rate pollution control revenue bonds and commercial paper programs. The amount of variable rate pollution control revenue bonds outstanding requiring liquidity support as of December 31, 2012 was approximately $1.8 billion.

The traditional operating companies may also meet short-term cash needs through a Southern Company subsidiary organized to issue and sell commercial paper at the request and for the benefit of each of the traditional operating companies.

Details of short-term borrowings were as follows:

	Short-term Debt at the End of the Period[a]		Short-term Debt During the Period [b]		
	Amount Outstanding	Weighted Average Interest Rate	Average Outstanding	Weighted Average Interest Rate	Maximum Amount Outstanding
	(in millions)		*(in millions)*		*(in millions)*
December 31, 2012:					
Commercial paper	**$ 820**	**0.3%**	**$ 550**	**0.3%**	**$ 938**
Short-term bank debt	**—**	**—%**	**116**	**1.2%**	**300**
Total	**$ 820**	**0.3%**	**$ 666**	**0.5%**	
December 31, 2011:					
Commercial paper	$ 654	0.3%	$ 697	0.3%	$ 1,586
Short-term bank debt	200	1.2%	14	1.2%	200
Total	$ 854	0.5%	$ 711	0.3%	
December 31, 2010:					
Commercial paper	$ 1,295	0.3%	$ 690	0.3%	$ 1,305

(a) Excludes notes payable related to other energy service contracts of $5 million, $6 million, and $2 million at December 31, 2012, 2011, and 2010, respectively.

(b) Average and maximum amounts are based upon daily balances during the twelve-month periods ended December 31, 2012, 2011, and 2010.

Management believes that the need for working capital can be adequately met by utilizing commercial paper programs, lines of credit, and cash.

Financing Activities

During 2012, Southern Company issued 12.1 million shares of common stock for approximately $397 million through the employee and director stock plans. Since mid-2011, Southern Company has issued additional equity only through its employee and director stock plans. In July 2012, Southern Company announced a program to repurchase shares to partially offset the incremental shares issued under its employee and director stock plans. Under this program, approximately 9 million shares have been repurchased through December 31, 2012 at a total cost of $430 million. Pursuant to Board approval, Southern Company may repurchase shares through open market purchases or privately negotiated transactions, in accordance with applicable securities laws.

In addition, Southern Company is not currently issuing shares of common stock through the Southern Investment Plan or its employee savings plan. All sales under the Southern Investment Plan and the employee savings plan are currently being funded with shares acquired on the open market by the independent plan administrators.

The following table outlines the long-term debt financing activities for Southern Company, the traditional operating companies, and Southern Power for the year ended December 31, 2012:

Company	Senior Note Issuances	Senior Note Redemptions and Maturities	Revenue Bond Issuances	Revenue Bond Redemptions and Maturities	Other Long-Term Debt Issuances	Other Long-Term Debt Redemptions and Maturities
			(in millions)			
Southern Company	$ —	$ 500	$ —	$ —	$ —	$ —
Alabama Power	1,000	950	—	1	—	—
Georgia Power	2,300	850	284	284	—	250
Gulf Power	100	91	13	13	—	—
Mississippi Power	600	90	—	—	101	115
Southern Power	—	—	—	—	6	2
Total	$ 4,000	$ 2,481	$ 297	$ 298	$ 107	$ 367

Southern Company's subsidiaries used the proceeds of the debt issuances shown in the table above for the redemptions and maturities shown in the table above, to repay short-term indebtedness, and for general corporate purposes, including their respective continuous construction programs.

In January 2012, Southern Company's $500 million aggregate principal amount of Series 2007A 5.30% Senior Notes matured.

The table above does not reflect Mississippi Power's receipt on March 6, 2012 of a $150 million interest-bearing refundable deposit from South Mississippi Electric Power Association (SMEPA) to be applied to the sale price for the pending sale of an undivided interest in the Kemper IGCC. Until the acquisition is closed, the deposit bears interest at Mississippi Power's AFUDC rate adjusted for income taxes, which was 9.967% per annum at December 31, 2012, and is refundable to SMEPA upon termination of the asset purchase agreement related to such purchase, within 60 days of a request by SMEPA for a full or partial refund, or within 15 days at SMEPA's discretion in the event that Mississippi Power is assigned a senior unsecured credit rating of BBB+ or lower by Standard and Poor's Rating Services, a division of The McGraw-Hill Companies, Inc. (S&P) or Baa1 or lower by Moody's Investors Service, Inc. (Moody's) or ceases to be rated by either of these rating agencies.

Mississippi Power's "Other Long-Term Debt Issuances" reflected in the table above include $51 million related to an agreement entered into by the Mississippi Business Finance Corporation in August 2012 for the issuance of up to $85 million of taxable revenue bonds for the benefit of Mississippi Power. During 2012, the Mississippi Business Finance Corporation issued $51 million of taxable revenue bonds under the agreement, the proceeds of which were used by Mississippi Power for the cost of the acquisition, construction, equipping, installation, and improvement of certain equipment and facilities for the lignite mining facility relating to the Kemper IGCC. Any future issuances of up to $34 million under the agreement will be used for the same purposes.

In addition, Mississippi Power's "Other Long-Term Debt Issuances" reflected in the table above includes a term loan borrowing of $50 million. In November 2012, Mississippi Power entered into a one-year $100 million aggregate principal amount floating rate term loan agreement that bears interest based on one-month London Interbank Offered Rate. The first advance in the amount of $50 million was made in November 2012. Subsequent to December 31, 2012, the second advance in the amount of $50 million was made. The proceeds of this loan were used solely for working capital and other general corporate purposes, including Mississippi Power's continuous construction program.

In addition to any financings that may be necessary to meet capital requirements and contractual obligations, Southern Company and its subsidiaries plan to continue, when economically feasible, a program to retire higher-cost securities and replace these obligations with lower-cost capital if market conditions permit.

Purchase of the Plant Daniel Combined Cycle Generating Units

In 2001, Mississippi Power began the initial 10-year term of an operating lease agreement for Plant Daniel Units 3 and 4.

In October 2011, Mississippi Power purchased Plant Daniel Units 3 and 4 for approximately $85 million in cash and the assumption of $270 million face value of debt obligations of the lessor related to Plant Daniel Units 3 and 4, which mature in 2021 and bear interest at a fixed stated interest rate of 7.13% per annum. These obligations are secured by Plant Daniel Units 3 and 4 and certain personal property. Accounting rules require that Plant Daniel Units 3 and 4 be reflected on Southern Company's financial statements at the time of the purchase at the fair value of the consideration rendered. Based on interest rates as of October 20, 2011, the fair value of the debt assumed was approximately $346 million. Accordingly, Plant Daniel Units 3 and 4 were reflected in Southern Company's financial statements at approximately $431 million.

In connection with the purchase of Plant Daniel Units 3 and 4, Mississippi Power filed a request in July 2011 for an accounting order from the Mississippi PSC. This order, as approved on January 11, 2012, authorized Mississippi Power to defer as a regulatory asset, for the 10-year period ending October 2021, the difference between the revenue requirement under the purchase option for Plant Daniel Units 3 and 4 (assuming a remaining 30-year life) and the revenue requirement assuming the continuation of the operating lease regulatory treatment with the accumulated deferred balance at the end of the deferral being amortized into rates over the remaining life of Plant Daniel Units 3 and 4. In November 2011, Mississippi Power filed a request with the FERC seeking the same accounting and regulatory treatment for its wholesale cost-based jurisdiction. The ultimate outcome of this matter cannot be determined at this time.

Credit Rating Risk

Southern Company and its subsidiaries do not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. There are certain contracts that could require collateral, but not accelerated payment, in the event of a credit rating change of certain subsidiaries to BBB and Baa2, or BBB- and/or Baa3 or below. These contracts are for physical electricity purchases and sales, fuel purchases, fuel transportation and storage, emissions allowances, energy price risk management, and construction of new generation.

The maximum potential collateral requirements under these contracts at December 31, 2012 were as follows:

Credit Ratings	Maximum Potential Collateral Requirements
	(in millions)
At BBB and Baa2	$ 9
At BBB- and/or Baa3	645
Below BBB- and/or Baa3	2,574

On March 6, 2012, Mississippi Power received a $150 million interest-bearing refundable deposit from SMEPA to be applied to the sale price for the pending sale of an undivided interest in the Kemper IGCC. Until the acquisition is closed, the deposit bears interest at Mississippi Power's AFUDC rate adjusted for income taxes, which was 9.967% per annum at December 31, 2012, and is refundable to SMEPA upon termination of the asset purchase agreement related to such purchase, within 60 days of a request by SMEPA for a full or partial refund, or within 15 days at SMEPA's discretion in the event that Mississippi Power is assigned a senior unsecured credit rating of BBB+ or lower by S&P or Baal or lower by Moody's or ceases to be rated by either of these rating agencies.

Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. Additionally, any credit rating downgrade could impact the ability of Southern Company and its subsidiaries to access capital markets, particularly the short-term debt market and the variable rate pollution control revenue bond market.

Market Price Risk

The Southern Company system is exposed to market risks, primarily commodity price risk and interest rate risk. The Southern Company system may also occasionally have limited exposure to foreign currency exchange rates. To manage the volatility attributable to these exposures, the applicable company nets the exposures, where possible, to take advantage of natural offsets and enters into various derivative transactions for the remaining exposures pursuant to the applicable company's policies in areas such as counterparty exposure and risk management practices. The Southern Company system's policy is that derivatives are to be used primarily for hedging purposes and mandates strict adherence to all applicable risk management policies. Derivative positions are monitored using techniques including, but not limited to, market valuation, value at risk, stress testing, and sensitivity analysis.

To mitigate future exposure to a change in interest rates, Southern Company and certain of its subsidiaries enter into derivatives that have been designated as hedges. Derivatives outstanding at December 31, 2012 have a notional amount of $350 million and are related to fixed and floating rate obligations over the next several years. The weighted average interest rate on $3.2 billion of long-term and short-term variable interest rate exposure that has not been hedged at January 1, 2013 was 0.73%. If Southern Company sustained a 100 basis point change in interest rates for all unhedged variable rate long-term debt and short-term bank loans, the change would affect annualized interest expense by approximately $32 million at January 1, 2013. See Note 1 to the financial statements under "Financial Instruments" and Note 11 to the financial statements for additional information.

Due to cost-based rate regulation and other various cost recovery mechanisms, the traditional operating companies continue to have limited exposure to market volatility in interest rates, foreign currency, commodity fuel prices, and prices of electricity. In addition, Southern Power's exposure to market volatility in commodity fuel prices and prices of electricity is limited because its long-term sales contracts shift substantially all fuel cost responsibility to the purchaser. However, Southern Power has been and may continue to be exposed to market volatility in energy-related commodity prices as a result of sales of uncontracted generating capacity. To mitigate residual risks relative to movements in electricity prices, the traditional operating companies enter into physical fixed-price contracts for the purchase and sale of electricity through the wholesale electricity market and, to a lesser extent, financial hedge contracts for natural gas purchases. The traditional operating companies continue to manage fuel hedging programs implemented per the guidelines of their respective state PSCs. Southern Company had no material change in market risk exposure for the year ended December 31, 2012 when compared to the December 31, 2011 reporting period.

The changes in fair value of energy-related derivative contracts, the majority of which are composed of regulatory hedges, for the years ended December 31 were as follows:

		2012 Changes		2011 Changes
		Fair Value		
		(in millions)		
Contracts outstanding at the beginning of the period, assets (liabilities), net	**$**	**(231)**	$	(196)
Contracts realized or settled		**206**		179
Current period changes[(a)]		**(60)**		(214)
Contracts outstanding at the end of the period, assets (liabilities), net	**$**	**(85)**	$	(231)

(a) Current period changes also include the changes in fair value of new contracts entered into during the period, if any.

The changes in the fair value positions of the energy-related derivative contracts, which are substantially all attributable to both the volume and the price of natural gas, for the years ended December 31 were as follows:

		2012 Changes		2011 Changes
		Fair Value		
		(in millions)		
Natural gas swaps	**$**	**128**	$	(20)
Natural gas options		**19**		(15)
Other energy-related derivatives		**(1)**		—
Total changes	**$**	**146**	$	(35)

The net hedge volumes of energy-related derivative contracts for the years ended December 31 were as follows:

	2012	2011
	mmBtu* Volume	
	(in millions)	
Commodity – Natural gas swaps	**171**	123
Commodity – Natural gas options	**105**	66
Total hedge volume	**276**	189

*million British thermal units (mmBtu)

The weighted average swap contract cost above market prices was approximately $0.39 per mmBtu as of December 31, 2012 and $1.51 per mmBtu as of December 31, 2011. The change in option fair value is primarily attributable to the volatility of the market and the underlying change in the natural gas price. The majority of the natural gas hedge gains and losses are recovered through the traditional operating companies' fuel cost recovery clauses.

At December 31, the net fair value of energy-related derivative contracts by hedge designation was reflected in the financial statements as follows:

Asset (Liability) Derivatives	**2012**	2011
	(in millions)	
Regulatory hedges	**$ (86)**	$ (221)
Cash flow hedges	**—**	(1)
Not designated	**1**	(9)
Total fair value	**$ (85)**	$ (231)

Energy-related derivative contracts which are designated as regulatory hedges relate to the traditional operating companies' fuel hedging programs, where gains and losses are initially recorded as regulatory liabilities and assets, respectively, and then are included in fuel expense as they are recovered through the fuel cost recovery clauses. Gains and losses on energy-related derivatives that are designated as cash flow hedges are mainly used by Southern Power to hedge anticipated purchases and sales and are initially deferred in other comprehensive income before being recognized in income in the same period as the hedged transaction. Gains and losses on energy-related derivative contracts that are not designated or fail to qualify as hedges are recognized in the statements of income as incurred.

Total net unrealized pre-tax gains (losses) recognized in the statements of income for the years ended December 31, 2012, 2011, and 2010 for energy-related derivative contracts that are not hedges were $9 million, $(6) million, and $(2) million, respectively.

Southern Company uses over-the-counter contracts that are not exchange traded but are fair valued using prices which are market observable, and thus fall into Level 2. See Note 10 to the financial statements for further discussion of fair value measurements. The maturities of the energy-related derivative contracts, which are all Level 2 of the fair value hierarchy, at December 31, 2012 were as follows:

	Fair Value Measurements December 31, 2012			
	Total Fair Value	Maturity		
		Year 1	Years 2&3	Years 4&5
		(in millions)		
Level 1	$ —	$ —	$ —	$ —
Level 2	(85)	(64)	(23)	2
Level 3	—	—	—	—
Fair value of contracts outstanding at end of period	$ (85)	$ (64)	$ (23)	$ 2

Southern Company is exposed to market price risk in the event of nonperformance by counterparties to energy-related and interest rate derivative contracts. Southern Company only enters into agreements and material transactions with counterparties that have investment grade credit ratings by Moody's and S&P, or with counterparties who have posted collateral to cover potential credit exposure. Therefore, Southern Company does not anticipate market risk exposure from nonperformance by the counterparties. For additional information, see Note 1 to the financial statements under "Financial Instruments" and Note 11 to the financial statements.

Southern Company performs periodic reviews of its leveraged lease transactions, both domestic and international, and the creditworthiness of the lessees, including a review of the value of the underlying leased assets and the credit ratings of the lessees. Southern Company's domestic lease transactions generally do not have any credit enhancement mechanisms; however, the lessees in its international lease transactions have pledged various deposits as additional security to secure the obligations. The lessees in the Company's international lease transactions are also required to provide additional collateral in the event of a credit downgrade below a certain level. See FUTURE EARNINGS POTENTIAL – "Investments in Leveraged Leases" herein for additional information.

Capital Requirements and Contractual Obligations

The Southern Company system's construction program is currently estimated to be $5.5 billion for 2013, $5.8 billion for 2014, and $5.2 billion for 2015. Included in this amount are expenditures related to the construction of the Kemper IGCC of $513 million and $218 million in 2013 and 2014, respectively, which are net of SMEPA's 15% proposed ownership share of the Kemper IGCC of approximately $492 million and $28 million in 2013 and 2014, respectively. The estimated share for SMEPA in 2013 reflects estimated construction costs relating to SMEPA's proposed ownership interest to be incurred through December 31, 2013 (including construction costs for all prior years relating to its proposed ownership interest). Capital expenditures to comply with existing environmental statutes and regulations included in these estimated amounts are $1.0 billion, $1.5 billion, and $1.1 billion for 2013, 2014, and 2015, respectively. These amounts include capital expenditures related to contractual purchase commitments for nuclear fuel and capital expenditures covered under long-term service agreements, as well as capital expenditures and compliance costs associated with the MATS rule.

See FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations" herein for additional information.

The construction programs are subject to periodic review and revision, and actual construction costs may vary from these estimates because of numerous factors. These factors include: changes in business conditions; changes in load projections; changes in the expected environmental compliance program; changes in environmental statutes and regulations; the outcome of any legal challenges to the environmental rules; changes in generating plants, including unit retirements and replacements and adding or changing fuel sources at existing units, to meet regulatory requirements; changes in FERC rules and regulations; PSC approvals; changes in legislation; the cost and efficiency of construction labor, equipment, and materials; project scope and design changes; storm impacts; and the cost of capital. In addition, there can be no assurance that costs related to capital expenditures will be fully recovered. See Note 3 to the financial statements under "Retail Regulatory Matters – Georgia Power – Nuclear Construction" and "Integrated Coal Gasification Combined Cycle" for additional information.

As a result of NRC requirements, Alabama Power and Georgia Power have external trust funds for nuclear decommissioning costs; however, Alabama Power currently has no additional funding requirements. For additional information, see Note 1 to the financial statements under "Nuclear Decommissioning."

In addition, as discussed in Note 2 to the financial statements, Southern Company provides postretirement benefits to substantially all employees and funds trusts to the extent required by the traditional operating companies' respective regulatory commissions.

Other funding requirements related to obligations associated with scheduled maturities of long-term debt, as well as the related interest, derivative obligations, preferred and preference stock dividends, leases, and other purchase commitments are detailed in the contractual obligations table that follows. See Notes 1, 2, 5, 6, 7, and 11 to the financial statements for additional information.

Contractual Obligations

	2013	2014-2015	2016-2017	After 2017	Uncertain Timing[d]	Total
			(in millions)			
Long-term debt[a] —						
Principal	$ 2,312	$ 2,866	$ 2,495	$ 13,804	$ —	$ 21,477
Interest	821	1,491	1,318	10,214	—	13,844
Preferred and preference stock dividends[b]	65	130	130	—	—	325
Financial derivative obligations[c]	75	35	1	—	—	111
Operating leases	113	148	77	84	—	422
Capital leases	23	21	15	21	—	80
Unrecognized tax benefits[d]	5	—	—	—	65	70
Purchase commitments —						
Capital[e]	4,987	10,013	—	—	—	15,000
Fuel[f]	4,518	6,070	2,638	3,280	—	16,506
Purchased power[g]	246	617	650	2,903	—	4,416
Other[h]	184	516	271	1,034	—	2,005
Trusts —						
Nuclear decommissioning[i]	2	4	4	31	—	41
Pension and other postretirement benefit plans[j]	102	201	—	—	—	303
Total	$ 13,453	$ 22,112	$ 7,599	$ 31,371	$ 65	$ 74,600

(a) All amounts are reflected based on final maturity dates. Southern Company and its subsidiaries plan to continue to retire higher-cost securities and replace these obligations with lower-cost capital if market conditions permit. Variable rate interest obligations are estimated based on rates as of January 1, 2013, as reflected in the statements of capitalization. Fixed rates include, where applicable, the effects of interest rate derivatives employed to manage interest rate risk. Long-term debt excludes capital lease amounts (shown separately).

(b) Represents preferred and preference stock of subsidiaries. Preferred and preference stock do not mature; therefore, amounts are provided for the next five years only.

(c) For additional information, see Notes 1 and 11 to the financial statements.

(d) The timing related to the realization of $65 million in unrecognized tax benefits in individual years beyond 12 months cannot be reasonably and reliably estimated due to uncertainties in the timing of the effective settlement of tax positions. See Note 5 to the financial statements under "Unrecognized Tax Benefits" for additional information.

(e) The Southern Company system provides estimated capital expenditures for a three-year period, including capital expenditures and compliance costs associated with existing environmental regulations, including the MATS rule. These amounts exclude contractual purchase commitments for nuclear fuel and capital expenditures covered under long-term service agreements which are reflected separately. At December 31, 2012, significant purchase commitments were outstanding in connection with the construction program. See FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations" herein for additional information.

(f) Primarily includes commitments to purchase coal, nuclear fuel, and natural gas, as well as the related transportation and storage. In most cases, these contracts contain provisions for price escalation, minimum purchase levels, and other financial commitments. Natural gas purchase commitments are based on various indices at the time of delivery. Amounts reflected for natural gas purchase commitments have been estimated based on the New York Mercantile Exchange future prices at December 31, 2012.

(g) Estimated minimum long-term obligations for various long-term commitments for the purchase of capacity and energy. Amounts include PPAs which include MWs purchased from gas-fired and wind-powered facilities.

(h) Includes long-term service agreements and contracts for the procurement of limestone. Long-term service agreements include price escalation based on inflation indices.

(i) Projections of nuclear decommissioning trust fund contributions are based on the 2010 ARP for Georgia Power.

(j) The Southern Company system forecasts contributions to the pension and other postretirement benefit plans over a three-year period. Southern Company anticipates no mandatory contributions to the qualified pension plan during the next three years. Amounts presented represent estimated benefit payments for the nonqualified pension plans, estimated non-trust benefit payments for the other postretirement benefit plans, and estimated contributions to the other postretirement benefit plan trusts, all of which will be made from corporate assets of Southern Company's subsidiaries. See Note 2 to the financial statements for additional information related to the pension and other postretirement benefit plans, including estimated benefit payments. Certain benefit payments will be made through the related benefit plans. Other benefit payments will be made from corporate assets of Southern Company's subsidiaries.

Cautionary Statement Regarding Forward-Looking Statements

Southern Company's 2012 Annual Report contains forward-looking statements. Forward-looking statements include, among other things, statements concerning retail sales, retail rates, the strategic goals for the wholesale business, customer growth, economic recovery, fuel and environmental cost recovery and other rate actions, current and proposed environmental regulations and related estimated expenditures, access to sources of capital, dividend payout ratios, projections for the qualified pension plan, postretirement benefit plan, and nuclear decommissioning trust fund contributions, financing activities, start and completion dates of construction projects, plans and estimated costs for new generation resources, filings with state and federal regulatory authorities, impact of the Tax Relief Act, impact of the ATRA, estimated sales and purchases under new power sale and purchase agreements, and estimated construction and other expenditures. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "could," "should," "expects," "plans," "anticipates," "believes," "estimates," "projects," "predicts," "potential," or "continue" or the negative of these terms or other similar terminology. There are various factors that could cause actual results to differ materially from those suggested by the forward-looking statements; accordingly, there can be no assurance that such indicated results will be realized. These factors include:

- the impact of recent and future federal and state regulatory changes, including legislative and regulatory initiatives regarding deregulation and restructuring of the electric utility industry, environmental laws including regulation of water, coal combustion byproducts, and emissions of sulfur, nitrogen, carbon, soot, particulate matter, hazardous air pollutants, including mercury, and other substances, financial reform legislation, and also changes in tax and other laws and regulations to which Southern Company and its subsidiaries are subject, as well as changes in application of existing laws and regulations;
- current and future litigation, regulatory investigations, proceedings, or inquiries, including the pending EPA civil actions against certain Southern Company subsidiaries, FERC matters, and Internal Revenue Service and state tax audits;
- the effects, extent, and timing of the entry of additional competition in the markets in which Southern Company's subsidiaries operate;
- variations in demand for electricity, including those relating to weather, the general economy and recovery from the recent recession, population and business growth (and declines), the effects of energy conservation measures, and any potential economic impacts resulting from federal fiscal decisions;
- available sources and costs of fuels;
- effects of inflation;
- ability to control costs and avoid cost overruns during the development and construction of facilities, including the development and construction of facilities with designs that have not been finalized or previously constructed, to construct facilities in accordance with the requirements of permits and licenses, and to satisfy any operational and environmental performance standards, including the requirements of tax credits and other incentives;
- investment performance of Southern Company's employee benefit plans and nuclear decommissioning trust funds;
- advances in technology;
- state and federal rate regulations and the impact of pending and future rate cases and negotiations, including rate actions relating to fuel and other cost recovery mechanisms;
- regulatory approvals and actions related to Plant Vogtle Units 3 and 4, including Georgia PSC approvals, NRC actions, and potential DOE loan guarantees;
- regulatory approvals and legislative actions related to the Kemper IGCC, including Mississippi PSC approvals and legislation relating to cost recovery for the Kemper IGCC, the SMEPA purchase decision, satisfaction of requirements to utilize investment tax credits and grants, and the outcome of any proceedings regarding the Mississippi PSC's issuance of the certificate of public convenience and necessity for the Kemper IGCC;
- the inherent risks involved in operating and constructing nuclear generating facilities, including environmental, health, regulatory, natural disaster, terrorism, or financial risks;
- the performance of projects undertaken by the non-utility businesses and the success of efforts to invest in and develop new opportunities;
- internal restructuring or other restructuring options that may be pursued;
- potential business strategies, including acquisitions or dispositions of assets or businesses, which cannot be assured to be completed or beneficial to Southern Company or its subsidiaries;
- the ability of counterparties of Southern Company and its subsidiaries to make payments as and when due and to perform as required;
- the ability to obtain new short- and long-term contracts with wholesale customers;
- the direct or indirect effect on the Southern Company system's business resulting from terrorist incidents and the threat of terrorist incidents, including cyber intrusion;

- interest rate fluctuations and financial market conditions and the results of financing efforts, including Southern Company's and its subsidiaries' credit ratings;
- the impacts of any potential U.S. credit rating downgrade or other sovereign financial issues, including impacts on interest rates, access to capital markets, impacts on currency exchange rates, counterparty performance, and the economy in general, as well as potential impacts on the availability or benefits of proposed DOE loan guarantees;
- the ability of Southern Company and its subsidiaries to obtain additional generating capacity at competitive prices;
- catastrophic events such as fires, earthquakes, explosions, floods, hurricanes, droughts, pandemic health events such as influenzas, or other similar occurrences;
- the direct or indirect effects on the Southern Company system's business resulting from incidents affecting the U.S. electric grid or operation of generating resources;
- the effect of accounting pronouncements issued periodically by standard setting bodies; and
- other factors discussed elsewhere herein and in other reports (including the Form 10-K) filed by Southern Company from time to time with the SEC.

Southern Company expressly disclaims any obligation to update any forward-looking statements.

CONSOLIDATED STATEMENTS OF INCOME
For the Years Ended December 31, 2012, 2011, and 2010
Southern Company and Subsidiary Companies 2012 Annual Report

	2012	2011	2010
		(in millions)	
Operating Revenues:			
Retail revenues	**$ 14,187**	$ 15,071	$ 14,791
Wholesale revenues	**1,675**	1,905	1,994
Other electric revenues	**616**	611	589
Other revenues	**59**	70	82
Total operating revenues	**16,537**	17,657	17,456
Operating Expenses:			
Fuel	**5,057**	6,262	6,699
Purchased power	**544**	608	563
Other operations and maintenance	**3,791**	3,938	4,010
MC Asset Recovery insurance settlement	**(19)**	—	—
Depreciation and amortization	**1,787**	1,717	1,513
Taxes other than income taxes	**914**	901	869
Total operating expenses	**12,074**	13,426	13,654
Operating Income	**4,463**	4,231	3,802
Other Income and (Expense):			
Allowance for equity funds used during construction	**143**	153	194
Interest income	**40**	21	24
Interest expense, net of amounts capitalized	**(859)**	(857)	(895)
Other income (expense), net	**(38)**	(61)	(59)
Total other income and (expense)	**(714)**	(744)	(736)
Earnings Before Income Taxes	**3,749**	3,487	3,066
Income taxes	**1,334**	1,219	1,026
Consolidated Net Income	**2,415**	2,268	2,040
Dividends on Preferred and Preference Stock of Subsidiaries	**65**	65	65
Consolidated Net Income After Dividends on Preferred and Preference Stock of Subsidiaries	**$ 2,350**	$ 2,203	$ 1,975
Common Stock Data:			
Earnings per share (EPS)—			
Basic EPS	**$ 2.70**	$ 2.57	$ 2.37
Diluted EPS	**2.67**	2.55	2.36
Average number of shares of common stock outstanding — (in millions)			
Basic	**871**	857	832
Diluted	**879**	864	837
Cash dividends paid per share of common stock	**$ 1.9425**	$ 1.8725	$ 1.8025

The accompanying notes are an integral part of these financial statements.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
For the Years Ended December 31, 2012, 2011, and 2010
Southern Company and Subsidiary Companies 2012 Annual Report

	2012	2011	2010
		(in millions)	
Consolidated Net Income	**$ 2,415**	$ 2,268	$ 2,040
Other comprehensive income:			
Qualifying hedges:			
Changes in fair value, net of tax of $(7), $(10), and $-, respectively	**(12)**	(18)	(1)
Reclassification adjustment for amounts included in net income, net of tax of $7, $6, and $9, respectively	**11**	9	15
Marketable securities:			
Change in fair value, net of tax of $-, $(2), and $(2), respectively	**—**	(4)	(3)
Pension and other postretirement benefit plans:			
Benefit plan net gain (loss), net of tax of $(2), $(1), and $1, respectively	**(3)**	(2)	6
Reclassification adjustment for amounts included in net income, net of tax of $(4), $(14), and $1, respectively	**(8)**	(26)	1
Total other comprehensive income (loss)	**(12)**	(41)	18
Dividends on preferred and preference stock of subsidiaries	**(65)**	(65)	(65)
Consolidated Comprehensive Income	**$ 2,338**	$ 2,162	$ 1,993

The accompanying notes are an integral part of these financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2012, 2011, and 2010
Southern Company and Subsidiary Companies 2012 Annual Report

	2012	2011	2010
		(in millions)	
Operating Activities:			
Consolidated net income	$ 2,415	$ 2,268	$ 2,040
Adjustments to reconcile consolidated net income to net cash provided from operating activities —			
Depreciation and amortization, total	2,145	2,048	1,831
Deferred income taxes	1,096	1,155	1,038
Allowance for equity funds used during construction	(143)	(153)	(194)
Pension, postretirement, and other employee benefits	(398)	(45)	(614)
Stock based compensation expense	55	42	33
Generation construction screening costs	—	—	(51)
Retail fuel cost-recovery - long-term	123	—	—
Other, net	56	15	(33)
Changes in certain current assets and liabilities —			
-Receivables	234	362	80
-Fossil fuel stock	(452)	(62)	135
-Materials and supplies	(97)	(60)	(30)
-Other current assets	(37)	(17)	(17)
-Accounts payable	(89)	(5)	4
-Accrued taxes	(71)	330	(308)
-Accrued compensation	(28)	10	180
-Retail fuel cost over recovery - short-term	129	(3)	(178)
-Other current liabilities	(40)	18	75
Net cash provided from operating activities	4,898	5,903	3,991
Investing Activities:			
Property additions	(4,809)	(4,525)	(4,086)
Investment in restricted cash	(280)	1	(50)
Distribution of restricted cash	284	63	25
Nuclear decommissioning trust fund purchases	(1,046)	(2,195)	(2,009)
Nuclear decommissioning trust fund sales	1,043	2,190	2,004
Cost of removal, net of salvage	(149)	(93)	(125)
Change in construction payables, net	(84)	198	29
Other investing activities	(127)	178	(44)
Net cash used for investing activities	(5,168)	(4,183)	(4,256)
Financing Activities:			
Increase (decrease) in notes payable, net	(30)	(438)	659
Proceeds —			
Long-term debt issuances	4,404	3,719	3,151
Interest-bearing refundable deposit related to asset sale	150	—	—
Common stock issuances	397	723	772
Redemptions and repurchases —			
Long-term debt	(3,169)	(3,170)	(2,966)
Common stock repurchased	(430)	—	—
Payment of common stock dividends	(1,693)	(1,601)	(1,496)
Payment of dividends on preferred and preference stock of subsidiaries	(65)	(65)	(65)
Other financing activities	19	(20)	(33)
Net cash provided from (used for) financing activities	(417)	(852)	22
Net Change in Cash and Cash Equivalents	(687)	868	(243)
Cash and Cash Equivalents at Beginning of Year	1,315	447	690
Cash and Cash Equivalents at End of Year	$ 628	$ 1,315	$ 447

The accompanying notes are an integral part of these financial statements.

CONSOLIDATED BALANCE SHEETS
At December 31, 2012 and 2011
Southern Company and Subsidiary Companies 2012 Annual Report

Assets	2012	2011
		(in millions)
Current Assets:		
Cash and cash equivalents	$ 628	$ 1,315
Restricted cash and cash equivalents	7	8
Receivables —		
Customer accounts receivable	961	1,074
Unbilled revenues	441	376
Under recovered regulatory clause revenues	29	143
Other accounts and notes receivable	235	282
Accumulated provision for uncollectible accounts	(17)	(26)
Fossil fuel stock, at average cost	1,819	1,367
Materials and supplies, at average cost	1,000	903
Vacation pay	165	160
Prepaid expenses	657	385
Other regulatory assets, current	163	239
Other current assets	74	46
Total current assets	6,162	6,272
Property, Plant, and Equipment:		
In service	63,251	59,744
Less accumulated depreciation	21,964	21,154
Plant in service, net of depreciation	41,287	38,590
Other utility plant, net	263	55
Nuclear fuel, at amortized cost	851	774
Construction work in progress	5,989	5,591
Total property, plant, and equipment	48,390	45,010
Other Property and Investments:		
Nuclear decommissioning trusts, at fair value	1,303	1,207
Leveraged leases	670	649
Miscellaneous property and investments	216	262
Total other property and investments	2,189	2,118
Deferred Charges and Other Assets:		
Deferred charges related to income taxes	1,385	1,365
Unamortized debt issuance expense	133	156
Unamortized loss on reacquired debt	309	285
Other regulatory assets, deferred	4,032	3,579
Other deferred charges and assets	549	482
Total deferred charges and other assets	6,408	5,867
Total Assets	$ 63,149	$ 59,267

The accompanying notes are an integral part of these financial statements.

CONSOLIDATED BALANCE SHEETS
At December 31, 2012 and 2011
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Liabilities and Stockholders' Equity	2012	2011
		(in millions)
Current Liabilities:		
Securities due within one year	$ 2,335	$ 1,717
Interest-bearing refundable deposit related to asset sale	150	—
Notes payable	825	859
Accounts payable	1,387	1,553
Customer deposits	370	347
Accrued taxes —		
Accrued income taxes	7	13
Unrecognized tax benefits	2	22
Other accrued taxes	391	425
Accrued interest	237	226
Accrued vacation pay	212	205
Accrued compensation	433	450
Liabilities from risk management activities	75	209
Other regulatory liabilities, current	107	125
Other current liabilities	483	426
Total current liabilities	7,014	6,577
Long-Term Debt (See accompanying statements)	19,274	18,647
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	9,938	8,809
Deferred credits related to income taxes	211	224
Accumulated deferred investment tax credits	894	611
Employee benefit obligations	2,540	2,442
Asset retirement obligations	1,748	1,321
Other cost of removal obligations	1,194	1,165
Other regulatory liabilities, deferred	289	297
Other deferred credits and liabilities	668	514
Total deferred credits and other liabilities	17,482	15,383
Total Liabilities	43,770	40,607
Redeemable Preferred Stock of Subsidiaries (See accompanying statements)	375	375
Total Stockholders' Equity (See accompanying statements)	19,004	18,285
Total Liabilities and Stockholders' Equity	$ 63,149	$ 59,267
Commitments and Contingent Matters (See notes)		

The accompanying notes are an integral part of these financial statements.

CONSOLIDATED STATEMENTS OF CAPITALIZATION
At December 31, 2012 and 2011
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		2012	2011	2012	2011
		(in millions)		*(percent of total)*	
Long-Term Debt:					
Long-term debt payable to affiliated trusts —					
Maturity	Interest Rates				
Variable rate (3.41% at 1/1/13) due 2042		**$ 206**	$ 206		
Total long-term debt payable to affiliated trusts		**206**	206		
Long-term senior notes and debt —					
Maturity	Interest Rates				
2012	4.85% to 5.30%	**—**	1,203		
2013	1.30% to 6.00%	**1,436**	1,436		
2014	4.15% to 4.90%	**434**	437		
2015	0.55% to 5.25%	**2,375**	1,175		
2016	1.95% to 5.30%	**1,360**	1,210		
2017	5.50% to 5.90%	**1,095**	1,095		
2018 through 2051	2.25% to 8.20%	**10,073**	8,702		
Variable rates (0.60% to 0.95% at 1/1/12) due 2012		**—**	490		
Variable rates (0.58% to 1.21% at 1/1/13) due 2013		**876**	650		
Total long-term senior notes and debt		**17,649**	16,398		
Other long-term debt —					
Pollution control revenue bonds —					
Maturity	Interest Rates				
2019 through 2049	0.55% to 6.00%	**1,593**	1,590		
Variable rate (0.13% at 1/1/13) due 2015		**54**	54		
Variable rate (0.17% at 1/1/13) due 2016		**4**	4		
Variable rate (0.13% to 0.17% at 1/1/13) due 2017		**36**	36		
Variable rates (0.08% to 0.24% at 1/1/13) due 2018 to 2052		**1,664**	1,667		
Plant Daniel revenue bonds (7.13%) due 2021		**270**	270		
Total other long-term debt		**3,621**	3,621		
Capitalized lease obligations		**80**	93		
Unamortized debt premium (related to plant acquisition)		**88**	78		
Unamortized debt discount		**(35)**	(32)		
Total long-term debt (annual interest requirement — $821 million)		**21,609**	20,364		
Less amount due within one year		**2,335**	1,717		
Long-term debt excluding amount due within one year		**19,274**	18,647	**49.9%**	50.0%

	2012	2011	2012	2011
	(in millions)		*(percent of total)*	
Redeemable Preferred Stock of Subsidiaries:				
Cumulative preferred stock				
$100 par or stated value — 4.20% to 5.44%				
Authorized — 20 million shares				
Outstanding — 1 million shares	**81**	81		
$1 par value — 5.20% to 5.83%				
Authorized — 28 million shares				
Outstanding — 12 million shares: $25 stated value	**294**	294		
Total redeemable preferred stock of subsidiaries (annual dividend requirement — $20 million)	**375**	375	**1.0**	1.0
Common Stockholders' Equity:				
Common stock, par value $5 per share —	**4,389**	4,328		
Authorized — 1.5 billion shares				
Issued — 2012: 878 million shares				
— 2011: 866 million shares				
Treasury — 2012: 10.0 million shares				
— 2011: 0.5 million shares				
Paid-in capital	**4,855**	4,410		
Treasury, at cost	**(450)**	(17)		
Retained earnings	**9,626**	8,968		
Accumulated other comprehensive income (loss)	**(123)**	(111)		
Total common stockholders' equity	**18,297**	17,578	**47.3**	47.1
Preferred and Preference Stock of Subsidiaries:				
Non-cumulative preferred stock				
$25 par value — 6.00% to 6.13%				
Authorized — 60 million shares				
Outstanding — 2 million shares	**45**	45		
Preference stock				
Authorized — 65 million shares				
Outstanding—$1 par value — 5.63% to 6.50%	**343**	343		
— 14 million shares (non-cumulative)				
— $100 par or stated value — 6.00% to 6.50%	**319**	319		
— 3 million shares (non-cumulative)				
Total preferred and preference stock of subsidiaries (annual dividend requirement — $45 million)	**707**	707	**1.8**	1.9
Total stockholders' equity	**19,004**	18,285		
Total Capitalization	**$ 38,653**	$ 37,307	**100.0%**	100.0%

The accompanying notes are an integral part of these financial statements.

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
For the Years Ended December 31, 2012, 2011, and 2010
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	Number of Common Shares		Common Stock				Accumulated Other Comprehensive	Preferred and Preference	
	Issued	Treasury	Par Value	Paid-In Capital	Treasury	Retained Earnings	Income (Loss)	Stock of Subsidiaries	Total
	(in thousands)		*(in millions)*						
Balance at December 31, 2009	820,152	(505)	$ 4,101	$ 2,995	$ (15)	$ 7,885	$ (88)	$ 707	$ 15,585
Net income after dividends on preferred and preference stock of subsidiaries	—	—	—	—	—	1,975	—	—	1,975
Other comprehensive income (loss)	—	—	—	—	—	—	18	—	18
Stock issued	23,662	—	118	654	—	—	—	—	772
Stock-based compensation	—	—	—	52	—	—	—	—	52
Cash dividends	—	—	—	—	—	(1,496)	—	—	(1,496)
Other	—	31	—	1	—	2	—	—	3
Balance at December 31, 2010	843,814	(474)	4,219	3,702	(15)	8,366	(70)	707	16,909
Net income after dividends on preferred and preference stock of subsidiaries	—	—	—	—	—	2,203	—	—	2,203
Other comprehensive income (loss)	—	—	—	—	—	—	(41)	—	(41)
Stock issued	21,850	—	109	616	—	—	—	—	725
Stock-based compensation	—	—	—	89	—	—	—	—	89
Cash dividends	—	—	—	—	—	(1,601)	—	—	(1,601)
Other	—	(65)	—	3	(2)	—	—	—	1
Balance at December 31, 2011	**865,664**	**(539)**	**4,328**	**4,410**	**(17)**	**8,968**	**(111)**	**707**	**18,285**
Net income after dividends on preferred and preference stock of subsidiaries	—	—	—	—	—	**2,350**	—	—	**2,350**
Other comprehensive income (loss)	—	—	—	—	—	—	**(12)**	—	**(12)**
Stock issued	**12,139**	—	**61**	**336**	—	—	—	—	**397**
Stock repurchased, at cost	—	**(9,440)**	—	—	**(430)**	—	—	—	**(430)**
Stock-based compensation	—	—	—	**106**	—	—	—	—	**106**
Cash dividends	—	—	—	—	—	**(1,693)**	—	—	**(1,693)**
Other	—	**(56)**	—	**3**	**(3)**	**1**	—	—	**1**
Balance at December 31, 2012	**877,803**	**(10,035)**	**$ 4,389**	**$ 4,855**	**$ (450)**	**$ 9,626**	**$ (123)**	**$ 707**	**$ 19,004**

The accompanying notes are an integral part of these financial statements.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

General

The Southern Company (Southern Company or the Company) is the parent company of four traditional operating companies, Southern Power Company (Southern Power), Southern Company Services, Inc. (SCS), Southern Communications Services, Inc. (SouthernLINC Wireless), Southern Company Holdings, Inc. (Southern Holdings), Southern Nuclear Operating Company, Inc. (Southern Nuclear), and other direct and indirect subsidiaries. The traditional operating companies – Alabama Power Company (Alabama Power), Georgia Power Company (Georgia Power), Gulf Power Company (Gulf Power), and Mississippi Power Company (Mississippi Power) – are vertically integrated utilities providing electric service in four Southeastern states. Southern Power constructs, acquires, owns, and manages generation assets, including renewable energy projects, and sells electricity at market-based rates in the wholesale market. SCS, the system service company, provides, at cost, specialized services to Southern Company and its subsidiary companies. SouthernLINC Wireless provides digital wireless communications for use by Southern Company and its subsidiary companies and also markets these services to the public and provides fiber cable services within the Southeast. Southern Holdings is an intermediate holding company subsidiary, primarily for Southern Company's investments in leveraged leases. Southern Nuclear operates and provides services to the Southern Company system's nuclear power plants.

The financial statements reflect Southern Company's investments in the subsidiaries on a consolidated basis. The equity method is used for entities in which the Company has significant influence but does not control and for variable interest entities (VIEs) where the Company has an equity investment, but is not the primary beneficiary. All material intercompany transactions have been eliminated in consolidation. Certain prior years' data presented in the financial statements have been reclassified to conform to the current year presentation.

The traditional operating companies, Southern Power, and certain of their subsidiaries are subject to regulation by the Federal Energy Regulatory Commission (FERC), and the traditional operating companies are also subject to regulation by their respective state public service commissions (PSC). The companies follow generally accepted accounting principles (GAAP) in the U.S. and comply with the accounting policies and practices prescribed by their respective commissions. The preparation of financial statements in conformity with GAAP requires the use of estimates, and the actual results may differ from those estimates.

Regulatory Assets and Liabilities

The traditional operating companies are subject to the provisions of the Financial Accounting Standards Board in accounting for the effects of rate regulation. Regulatory assets represent probable future revenues associated with certain costs that are expected to be recovered from customers through the ratemaking process. Regulatory liabilities represent probable future reductions in revenues associated with amounts that are expected to be credited to customers through the ratemaking process.

Regulatory assets and (liabilities) reflected in the balance sheets at December 31 relate to:

	2012	2011	Note
	(in millions)		
Deferred income tax charges	$ 1,318	$ 1,293	(a)
Deferred income tax charges — Medicare subsidy	72	77	(j)
Asset retirement obligations-asset	141	117	(a,h)
Asset retirement obligations-liability	(71)	(42)	(a,h)
Other cost of removal obligations	(1,225)	(1,196)	(a)
Deferred income tax credits	(212)	(225)	(a)
State income tax credits	(36)	(62)	(k)
Loss on reacquired debt	309	285	(b)
Vacation pay	165	160	(c,h)
Under recovered regulatory clause revenues	38	50	(d)
Over recovered regulatory clause revenues	(18)	(28)	(d)
Building leases	40	43	(f)
Generating plant outage costs	30	38	(l)
Under recovered storm damage costs	38	43	(d)
Property damage reserves	(193)	(206)	(g)
Cancelled construction projects	65	12	(m)
Power purchase agreement charges	138	95	(h,n)
Fuel hedging-asset	118	249	(d)
Fuel hedging-liability	(24)	(13)	(d)
Other regulatory assets	204	183	(d)
Environmental remediation-asset	74	71	(g,h)
Environmental remediation-liability	(8)	(8)	(g)
Other regulatory liabilities	(14)	(30)	(d,i)
Retiree benefit plans	3,373	2,959	(e,h)
Total regulatory assets (liabilities), net	$ 4,322	$ 3,865	

Note: The recovery and amortization periods for these regulatory assets and (liabilities) are as follows:

(a) Asset retirement and removal assets and liabilities are recorded, deferred income tax assets are recovered, and deferred income tax liabilities are amortized over the related property lives, which may range up to 65 years. Asset retirement and removal assets and liabilities will be settled and trued up following completion of the related activities. At December 31, 2012, other cost of removal obligations included $31 million that will be amortized during 2013 in accordance with an Alternate Rate Plan for Georgia Power for the years 2011 through 2013 (2010 ARP). See Note 3 under "Retail Regulatory Matters – Georgia Power – Rate Plans" for additional information.

(b) Recovered over either the remaining life of the original issue or, if refinanced, over the life of the new issue, which may range up to 50 years.

(c) Recorded as earned by employees and recovered as paid, generally within one year. This includes both vacation and banked holiday pay.

(d) Recorded and recovered or amortized as approved or accepted by the appropriate state PSCs over periods generally not exceeding 10 years.

(e) Recovered and amortized over the average remaining service period which may range up to 15 years. See Note 2 for additional information.

(f) Recovered over the remaining lives of the buildings through 2026.

(g) Recovered as storm restoration and potential reliability-related expenses or environmental remediation expenses are incurred as approved by the appropriate state PSCs.

(h) Not earning a return as offset in rate base by a corresponding asset or liability.

(i) Recovered and amortized as approved or accepted by the appropriate state PSC over the life of the contract.

(j) Recovered and amortized as approved by the appropriate state PSCs over periods not exceeding 15 years.

(k) Additional tax benefits resulting from the Georgia state income tax credit settlement that are being amortized over a 21-month period that began in April 2012, in accordance with a Georgia PSC order.

(l) Recovered over the respective operating cycles, which range from 18 months to 10 years. See "Property, Plant, and Equipment" herein for additional information.

(m) Costs associated with construction of environmental controls that will not be completed as a result of unit retirements and deferred in accordance with the 2010 ARP. Amortization is expected to begin January 1, 2014, subject to approval by the Georgia PSC.

(n) Recovered over the life of the power purchase agreement (PPA) for periods up to 14 years.

In the event that a portion of a traditional operating company's operations is no longer subject to applicable accounting rules for rate regulation, such company would be required to write off to income or reclassify to accumulated other comprehensive income (OCI) related regulatory assets and liabilities that are not specifically recoverable through regulated rates. In addition, the traditional operating company would be required to determine if any impairment to other assets, including plant, exists and write down the assets, if impaired, to their fair values. All regulatory assets and liabilities are to be reflected in rates. See Note 3 under "Retail Regulatory Matters – Alabama Power," "Retail Regulatory Matters – Georgia Power," and "Integrated Coal Gasification Combined Cycle" for additional information.

Revenues

Wholesale capacity revenues are generally recognized on a levelized basis over the appropriate contract period. Energy and other revenues are recognized as services are provided. Unbilled revenues related to retail sales are accrued at the end of each fiscal period. Electric rates for the traditional operating companies include provisions to adjust billings for fluctuations in fuel costs, fuel hedging, the energy component of purchased power costs, and certain other costs. Revenues are adjusted for differences between these actual costs and amounts billed in current regulated rates. Under or over recovered regulatory clause revenues are recorded in the balance sheets and are recovered or returned to customers through adjustments to the billing factors.

Southern Company's electric utility subsidiaries have a diversified base of customers. No single customer or industry comprises 10% or more of revenues. For all periods presented, uncollectible accounts averaged less than 1% of revenues.

Fuel Costs

Fuel costs are expensed as the fuel is used. Fuel expense generally includes fuel transportation costs and the cost of purchased emissions allowances as they are used. Fuel expense also includes the amortization of the cost of nuclear fuel and a charge, based on nuclear generation, for the permanent disposal of spent nuclear fuel. See Note 3 under "Nuclear Fuel Disposal Costs" for additional information.

Income and Other Taxes

Southern Company uses the liability method of accounting for deferred income taxes and provides deferred income taxes for all significant income tax temporary differences. Taxes that are collected from customers on behalf of governmental agencies to be remitted to these agencies are presented net on the statements of income.

In accordance with regulatory requirements, deferred investment tax credits (ITCs) for the traditional operating companies are amortized over the lives of the related property with such amortization normally applied as a credit to reduce depreciation in the statements of income. Credits amortized in this manner amounted to $23 million in 2012, $19 million in 2011, and $23 million in 2010. At December 31, 2012, all ITCs available to reduce federal income taxes payable had not been utilized. The remaining ITCs will be carried forward and utilized in future years.

Under the American Recovery and Reinvestment Act of 2009, certain projects at certain Southern Company subsidiaries are eligible for ITCs or cash grants. These subsidiaries have elected to receive ITCs. The credits are recorded as a deferred credit, and are amortized to income tax expense over the life of the asset. Credits amortized in this manner amounted to $2.6 million and $0.9 million in 2012 and 2011, respectively. Furthermore, the tax basis of the asset is reduced by 50% of the credits received, resulting in a deferred tax asset. The subsidiaries have elected to recognize the tax benefit of this basis difference as a reduction to income tax expense as costs are incurred during the construction period. These basis differences will reverse and be recorded to income tax expense over the useful life of the asset once placed in service.

In accordance with accounting standards related to the uncertainty in income taxes, Southern Company recognizes tax positions that are "more likely than not" of being sustained upon examination by the appropriate taxing authorities. See Note 5 under "Unrecognized Tax Benefits" for additional information.

Property, Plant, and Equipment

Property, plant, and equipment is stated at original cost less any regulatory disallowances and impairments. Original cost includes: materials; labor; minor items of property; appropriate administrative and general costs; payroll-related costs such as taxes, pensions, and other benefits; and the interest capitalized and cost of equity funds used during construction.

The Southern Company system's property, plant, and equipment in service consisted of the following at December 31:

	2012	2011
	(in millions)	
Generation	$ 33,444	$ 31,751
Transmission	8,747	8,240
Distribution	15,958	15,458
General	4,208	3,413
Plant acquisition adjustment	124	124
Utility plant in service	62,481	58,986
Information technology equipment and software	230	220
Communications equipment	430	428
Other	110	110
Other plant in service	770	758
Total plant in service	$ 63,251	$ 59,744

The cost of replacements of property, exclusive of minor items of property, is capitalized. The cost of maintenance, repairs, and replacement of minor items of property is charged to other operations and maintenance expense as incurred or performed with the exception of nuclear refueling costs, which are recorded in accordance with specific state PSC orders. Alabama Power and Georgia Power defer and amortize nuclear refueling costs over the unit's operating cycle. The refueling cycles for Alabama Power and Georgia Power range from 18 to 24 months for each unit. In accordance with a Georgia PSC order, Georgia Power also defers the costs of certain significant inspection costs for the combustion turbines at Plant McIntosh and amortizes such costs over 10 years, which approximates the expected maintenance cycle.

The amount of non-cash property additions recognized for the years ended December 31, 2012, 2011, and 2010 was $524 million, $929 million, and $427 million, respectively. These amounts are comprised of construction related accounts payable outstanding at each year end together with retention amounts accrued during the respective year.

Included in the non-cash property additions for the year ended December 31, 2011 was $346 million for the fair value of the debt assumed for Mississippi Power's purchase of the combined cycle generating units 3 and 4 built at Plant Daniel (Plant Daniel Units 3 and 4). In October 2011, Mississippi Power purchased Plant Daniel Units 3 and 4 for approximately $85 million in cash and the assumption of $270 million face value of debt obligations of the lessor related to Plant Daniel Units 3 and 4, which mature in 2021 and bear interest at a fixed stated interest rate of 7.13% per annum. These obligations are secured by Plant Daniel Units 3 and 4 and certain personal property. Accounting rules require that Plant Daniel Units 3 and 4 be reflected on Southern Company's financial statements at the time of the purchase at the fair value of the consideration rendered. Based on interest rates as of October 20, 2011, the fair value of the debt assumed was approximately $346 million. The fair value of the debt was determined using a discounted cash flow model based on Mississippi Power's borrowing rate at the closing date. The fair value is considered a Level 2 disclosure for financial reporting purposes. Accordingly, Plant Daniel Units 3 and 4 are reflected in Southern Company's financial statements at approximately $431 million.

Southern Power acquires generation assets as part of its overall growth strategy. Southern Power accounts for business acquisitions from non-affiliates as business combinations utilizing the acquisition method in accordance with GAAP. Accordingly, Southern Power has included these operations in the consolidated financial statements from the respective date of acquisition. The purchase price, including contingent consideration, if any, of each acquisition was allocated based on the fair value of the identifiable assets and liabilities. Assets acquired that do not meet the definition of a business in accordance with GAAP are accounted for as asset acquisitions. The purchase price of each asset acquisition was allocated based on the relative fair value of assets acquired. Any due diligence or transition costs incurred by Southern Power for successful or potential acquisitions have been expensed as incurred.

Depreciation and Amortization

Depreciation of the original cost of utility plant in service is provided primarily by using composite straight-line rates, which approximated 3.2% in 2012, 3.2% in 2011, and 3.3% in 2010. Depreciation studies are conducted periodically to update the composite rates. These studies are filed with the respective state PSC and the FERC for the traditional operating companies. Accumulated depreciation for utility plant in service totaled $21.5 billion and $20.7 billion at December 31, 2012 and 2011,

respectively. When property subject to composite depreciation is retired or otherwise disposed of in the normal course of business, its original cost, together with the cost of removal, less salvage, is charged to accumulated depreciation. For other property dispositions, the applicable cost and accumulated depreciation are removed from the balance sheet accounts, and a gain or loss is recognized. Minor items of property included in the original cost of the plant are retired when the related property unit is retired.

In 2009, the Georgia PSC approved an accounting order allowing Georgia Power to amortize a portion of its regulatory liability related to other cost of removal obligations. Under the terms of the 2010 ARP, Georgia Power is amortizing approximately $31 million annually of the remaining regulatory liability related to other cost of removal obligations over the three years ending December 31, 2013. See Note 3 under "Retail Regulatory Matters – Georgia Power – Rate Plans" for additional information.

Depreciation of the original cost of other plant in service is provided primarily on a straight-line basis over estimated useful lives ranging from three to 25 years. Accumulated depreciation for other plant in service totaled $479 million and $456 million at December 31, 2012 and 2011, respectively.

Asset Retirement Obligations and Other Costs of Removal

Asset retirement obligations are computed as the present value of the ultimate costs for an asset's future retirement and are recorded in the period in which the liability is incurred. The costs are capitalized as part of the related long-lived asset and depreciated over the asset's useful life. Each traditional operating company has received accounting guidance from the various state PSCs allowing the continued accrual of other future retirement costs for long-lived assets that it does not have a legal obligation to retire. Accordingly, the accumulated removal costs for these obligations are reflected in the balance sheets as a regulatory liability. See Note 3 under "Retail Regulatory Matters – Georgia Power – Rate Plans" for additional information related to Georgia Power's cost of removal regulatory liability.

The liability for asset retirement obligations primarily relates to the decommissioning of the Southern Company system's nuclear facilities, Plants Farley, Hatch, and Vogtle. In addition, the Southern Company system has retirement obligations related to various landfill sites, ash ponds, underground storage tanks, asbestos removal, and disposal of polychlorinated biphenyls in certain transformers. The Southern Company system also has identified retirement obligations related to certain transmission and distribution facilities, co-generation facilities, certain wireless communication towers, and certain structures authorized by the U.S. Army Corps of Engineers. However, liabilities for the removal of these assets have not been recorded because the range of time over which the applicable company may settle these obligations is unknown and cannot be reasonably estimated. The Company will continue to recognize in the statements of income allowed removal costs in accordance with regulatory treatment. Any differences between costs recognized in accordance with accounting standards related to asset retirement and environmental obligations and those reflected in rates are recognized as either a regulatory asset or liability, as ordered by the various state PSCs, and are reflected in the balance sheets. See "Nuclear Decommissioning" herein for additional information on amounts included in rates.

Details of the asset retirement obligations included in the balance sheets are as follows:

	2012	2011
	(in millions)	
Balance at beginning of year	$ 1,344	$ 1,266
Liabilities incurred	45	1
Liabilities settled	(16)	(13)
Accretion	112	82
Cash flow revisions	272	8
Balance at end of year	$ 1,757	$ 1,344

Nuclear Decommissioning

The Nuclear Regulatory Commission (NRC) requires licensees of commercial nuclear power reactors to establish a plan for providing reasonable assurance of funds for future decommissioning. Alabama Power and Georgia Power have external trust funds (Funds) to comply with the NRC's regulations. Use of the Funds is restricted to nuclear decommissioning activities. The Funds are managed and invested in accordance with applicable requirements of various regulatory bodies, including the NRC, the FERC, and state PSCs, as well as the Internal Revenue Service (IRS). The Funds are required to be held by one or more trustees with an individual net worth of at least $100 million. The FERC requires the Funds' managers to exercise the standard of care in investing that a "prudent investor" would use in the same circumstances. The FERC regulations also require that the Funds'

managers may not invest in any securities of the utility for which it manages funds or its affiliates, except for investments tied to market indices or other mutual funds. While Southern Company is allowed to prescribe an overall investment policy to the Funds' managers, neither Southern Company nor its subsidiaries or affiliates are allowed to engage in the day-to-day management of the Funds or to mandate individual investment decisions. Day-to-day management of the investments in the Funds is delegated to unrelated third party managers with oversight by the management of Southern Company, Alabama Power, and Georgia Power. The Funds' managers are authorized, within certain investment guidelines, to actively buy and sell securities at their own discretion in order to maximize the return on the Funds' investments. The Funds are invested in a tax-efficient manner in a diversified mix of equity and fixed income securities and are reported as trading securities.

Southern Company records the investment securities held in the Funds at fair value, as disclosed in Note 10, as management believes that fair value best represents the nature of the Funds. Gains and losses, whether realized or unrealized, are recorded in the regulatory liability for asset retirement obligations in the balance sheets and are not included in net income or OCI. Fair value adjustments and realized gains and losses are determined on a specific identification basis.

The Funds at Georgia Power participate in a securities lending program through the managers of the Funds. Under this program, the Funds' investment securities are loaned to institutional investors for a fee. Securities so loaned are fully collateralized by cash, letters of credit, and securities issued or guaranteed by the U.S. government, its agencies, and the instrumentalities. As of December 31, 2012 and 2011, approximately $91 million and $39 million, respectively, of the fair market value of the Funds' securities were on loan and pledged to creditors under the Funds' managers' securities lending program. The fair value of the collateral received was approximately $93 million and $42 million at December 31, 2012 and 2011, respectively, and can only be sold by the borrower upon the return of the loaned securities. The collateral received is treated as a non-cash item in the statements of cash flows.

At December 31, 2012, investment securities in the Funds totaled $1.3 billion consisting of equity securities of $718 million, debt securities of $564 million, and $20 million of other securities. At December 31, 2011, investment securities in the Funds totaled $1.2 billion consisting of equity securities of $626 million, debt securities of $543 million, and $36 million of other securities. These amounts include the investment securities pledged to creditors and collateral received and exclude receivables related to investment income and pending investment sales and payables related to pending investment purchases and the lending pool.

Sales of the securities held in the Funds resulted in cash proceeds of $1.0 billion, $2.2 billion, and $2.0 billion in 2012, 2011, and 2010, respectively, all of which were reinvested. For 2012, fair value increases, including reinvested interest and dividends and excluding the Funds' expenses, were $137 million, of which $4 million related to realized gains and $75 million related to unrealized gains related to securities held in the Funds at December 31, 2012. For 2011, fair value increases, including reinvested interest and dividends and excluding the Funds' expenses, were $29 million, of which $41 million related to realized gains and $60 million related to unrealized losses related to securities held in the Funds at December 31, 2011. For 2010, fair value increases, including reinvested interest and dividends and excluding the Funds' expenses, were $139 million, of which $6 million related to securities held in the Funds at December 31, 2010. While the investment securities held in the Funds are reported as trading securities, the Funds continue to be managed with a long-term focus. Accordingly, all purchases and sales within the Funds are presented separately in the statements of cash flows as investing cash flows, consistent with the nature of and purpose for which the securities were acquired.

For Alabama Power, amounts previously recorded in internal reserves are being transferred into the Funds over periods approved by the Alabama PSC. The NRC's minimum external funding requirements are based on a generic estimate of the cost to decommission only the radioactive portions of a nuclear unit based on the size and type of reactor. Alabama Power and Georgia Power have filed plans with the NRC designed to ensure that, over time, the deposits and earnings of the Funds will provide the minimum funding amounts prescribed by the NRC.

At December 31, 2012, the accumulated provisions for decommissioning were as follows:

	Plant Farley	Plant Hatch	Plant Vogtle Units 1 and 2
		(in millions)	
External trust funds	$ 604	$ 435	$ 256
Internal reserves	22	—	—
Total	$ 626	$ 435	$ 256

Site study cost is the estimate to decommission a specific facility as of the site study year. The estimated costs of decommissioning based on the most current studies, which were performed in 2008 for Alabama Power's Plant Farley and in 2012 for the Georgia Power plants, were as follows for Alabama Power's Plant Farley and Georgia Power's ownership interests in Plant Hatch and Plant Vogtle Units 1 and 2:

	Plant Farley	Plant Hatch	Plant Vogtle Units 1 and 2
Decommissioning periods:			
Beginning year	2037	2034	2047
Completion year	2065	2068	2072
		(in millions)	
Site study costs:			
Radiated structures	$ 1,060	$ 680	$ 568
Non-radiated structures	72	51	76
Total site study costs	$ 1,132	$ 731	$ 644

The decommissioning periods and site study costs for Plant Vogtle Units 1 and 2 reflect the extended operating license approved by the NRC in 2009. The decommissioning cost estimates are based on prompt dismantlement and removal of the plant from service. The actual decommissioning costs may vary from the above estimates because of changes in the assumed date of decommissioning, changes in NRC requirements, or changes in the assumptions used in making these estimates.

For ratemaking purposes, Alabama Power's decommissioning costs are based on the site study, and Georgia Power's decommissioning costs are based on the NRC generic estimate to decommission the radioactive portion of the facilities and the site study estimate for spent fuel management as of 2009. Effective for the years 2011 through 2013, the annual decommissioning cost for ratemaking is $2 million for Plant Hatch. Georgia Power expects the Georgia PSC to periodically review and adjust, if necessary, the amounts collected in rates for nuclear decommissioning costs. Significant assumptions used to determine these costs for ratemaking were an inflation rate of 4.5% and 2.4% for Alabama Power and Georgia Power, respectively, and a trust earnings rate of 7.0% and 4.4% for Alabama Power and Georgia Power, respectively.

Amounts previously contributed to the Funds for Plant Farley are currently projected to be adequate to meet the decommissioning obligations. Alabama Power will continue to provide site specific estimates of the decommissioning costs and related projections of funds in the external trust to the Alabama PSC and, if necessary, would seek the Alabama PSC's approval to address any changes in a manner consistent with NRC and other applicable requirements.

Allowance for Funds Used During Construction and Interest Capitalized

In accordance with regulatory treatment, the traditional operating companies record allowance for funds used during construction (AFUDC), which represents the estimated debt and equity costs of capital funds that are necessary to finance the construction of new regulated facilities. While cash is not realized currently from such allowance, AFUDC increases the revenue requirement over the service life of the plant through a higher rate base and higher depreciation. The equity component of AFUDC is not included in calculating taxable income. Interest related to the construction of new facilities not included in the traditional operating companies' regulated rates is capitalized in accordance with standard interest capitalization requirements. AFUDC and interest capitalized, net of income taxes were 8.2%, 9.1%, and 12.5% of net income for 2012, 2011, and 2010, respectively.

Cash payments for interest totaled $803 million, $832 million, and $789 million in 2012, 2011, and 2010, respectively, net of amounts capitalized of $83 million, $78 million, and $86 million, respectively.

Impairment of Long-Lived Assets and Intangibles

Southern Company evaluates long-lived assets for impairment when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. The determination of whether an impairment has occurred is based on either a specific regulatory disallowance or an estimate of undiscounted future cash flows attributable to the assets, as compared with the carrying value of the assets. If an impairment has occurred, the amount of the impairment recognized is determined by either the amount of regulatory disallowance or by estimating the fair value of the assets and recording a loss if the carrying value is greater than the fair value. For assets identified as held for sale, the carrying value is compared to the estimated fair value less the cost to sell in order to determine if an impairment loss is required. Until the assets are disposed of, their estimated fair value is re-evaluated when circumstances or events change.

Storm Damage Reserves

Each traditional operating company maintains a reserve to cover the cost of damages from major storms to its transmission and distribution lines and generally the cost of uninsured damages to its generation facilities and other property. In accordance with their respective state PSC orders, the traditional operating companies accrued $28 million in 2012 and $29 million in 2011. Alabama Power, Gulf Power, and Mississippi Power also have the authority based on orders from their state PSCs to accrue certain additional amounts as circumstances warrant. In 2012, there were no such additional accruals. In 2011, such additional accruals totaled $31 million, all at Alabama Power. See Note 3 under "Retail Regulatory Matters – Alabama Power – Natural Disaster Reserve" for additional information regarding Alabama Power's natural disaster reserve.

Leveraged Leases

Southern Company has several leveraged lease agreements, with original terms ranging up to 45 years, which relate to international and domestic energy generation, distribution, and transportation assets. Southern Company receives federal income tax deductions for depreciation and amortization, as well as interest on long-term debt related to these investments. The Company reviews all important lease assumptions at least annually, or more frequently if events or changes in circumstances indicate that a change in assumptions has occurred or may occur. These assumptions include the effective tax rate, the residual value, the credit quality of the lessees, and the timing of expected tax cash flows.

The recent financial and operational performance of one of Southern Company's lessees and the associated generation assets has raised potential concerns on the part of Southern Company as to the credit quality of the lessee and the residual value of the assets. Due to the poor performance of the generation assets and the uncertainties surrounding the receipt of future rent payments and its ability to successfully restructure the project, Southern Company placed the lease on nonaccrual status whereby, effective July 2012, income associated with this investment is not recognized in the financial statements. The lessee was unable to pay its December 2012 semiannual rent payment in full. To avoid a default on the lease and the project's nonrecourse debt, the due date for the December 2012 rent payment and the associated debt payment was extended to March 6, 2013 while restructuring negotiations continued between the parties to the transaction. The aim of the negotiations is to restructure the debt payments and the related rental payments to allow additional capital investment in the project to be made by Southern Company to improve the operation of the generation assets. Such operational improvements are projected to provide sufficient cash flows for Southern Company to realize the full amount of its investment in the lease receivable. The parties to the lease have reached general agreement as to the restructuring and Southern Company believes that it is likely that it will be able to complete the restructuring prior to the end of the first quarter 2013. If the restructuring is successfully completed, Southern Company will be required to record a reduction in leveraged lease income of up to approximately $17 million at that time. However, if the restructuring is unsuccessful and the project is ultimately abandoned, the potential impairment loss that would be incurred is approximately $90 million on an after-tax basis. The ultimate outcome of this matter cannot be determined at this time.

Southern Company's net investment in domestic and international leveraged leases consists of the following at December 31:

	2012	2011
	(in millions)	
Net rentals receivable	$ 1,214	$ 1,216
Unearned income	(544)	(567)
Investment in leveraged leases	670	649
Deferred taxes from leveraged leases	(278)	(277)
Net investment in leveraged leases	$ 392	$ 372

A summary of the components of income from the leveraged leases follows:

	2012	2011	2010
		(in millions)	
Pretax leveraged lease income	$ 21	$ 25	$ 18
Income tax expense	(8)	(9)	(8)
Net leveraged lease income	$ 13	$ 16	$ 10

Cash and Cash Equivalents

For purposes of the financial statements, temporary cash investments are considered cash equivalents. Temporary cash investments are securities with original maturities of 90 days or less.

Materials and Supplies

Generally, materials and supplies include the average cost of transmission, distribution, and generating plant materials. Materials are charged to inventory when purchased and then expensed or capitalized to plant, as appropriate, at weighted average cost when installed.

Fuel Inventory

Fuel inventory includes the average cost of coal, natural gas, oil, transportation, and emissions allowances. Fuel is charged to inventory when purchased and then expensed, at weighted average cost, as used and recovered by the traditional operating companies through fuel cost recovery rates approved by each state PSC. Emissions allowances granted by the Environmental Protection Agency (EPA) are included in inventory at zero cost.

Financial Instruments

Southern Company and its subsidiaries use derivative financial instruments to limit exposure to fluctuations in interest rates, the prices of certain fuel purchases, electricity purchases and sales, and occasionally foreign currency exchange rates. All derivative financial instruments are recognized as either assets or liabilities (included in "Other" or shown separately as "Risk Management Activities") and are measured at fair value. See Note 10 for additional information. Substantially all of the Southern Company system's bulk energy purchases and sales contracts that meet the definition of a derivative are excluded from fair value accounting requirements because they qualify for the "normal" scope exception, and are accounted for under the accrual method. Other derivative contracts qualify as cash flow hedges of anticipated transactions or are recoverable through the traditional operating companies' fuel hedging programs. This results in the deferral of related gains and losses in OCI or regulatory assets and liabilities, respectively, until the hedged transactions occur. Any ineffectiveness arising from cash flow hedges is recognized currently in net income. Other derivative contracts are marked to market through current period income and are recorded on a net basis in the statements of income. See Note 11 for additional information.

The Company does not offset fair value amounts recognized for multiple derivative instruments executed with the same counterparty under a master netting arrangement. At December 31, 2012, the amount included in accounts payable in the balance sheets that the Company has recognized for the obligation to return cash collateral arising from derivative instruments was immaterial.

Southern Company is exposed to losses related to financial instruments in the event of counterparties' nonperformance. The Company has established controls to determine and monitor the creditworthiness of counterparties in order to mitigate the Company's exposure to counterparty credit risk.

Comprehensive Income

The objective of comprehensive income is to report a measure of all changes in common stock equity of an enterprise that result from transactions and other economic events of the period other than transactions with owners. Comprehensive income consists of net income, changes in the fair value of qualifying cash flow hedges and marketable securities, certain changes in pension and other postretirement benefit plans, reclassifications for amounts included in net income, and dividends on preferred and preference stock of subsidiaries.

Accumulated OCI (loss) balances, net of tax effects, were as follows:

	Qualifying Hedges	Marketable Securities	Pension and Other Postretirement Benefit Plans	Accumulated Other Comprehensive Income (Loss)
		(in millions)		
Balance at December 31, 2011	$ (44)	$ 3	$ (70)	$ (111)
Current period change	(1)	—	(11)	(12)
Balance at December 31, 2012	**$ (45)**	**$ 3**	**$ (81)**	**$ (123)**

2. RETIREMENT BENEFITS

Southern Company has a defined benefit, trusteed, pension plan covering substantially all employees. This qualified pension plan is funded in accordance with requirements of the Employee Retirement Income Security Act of 1974, as amended (ERISA). In December 2012, certain of the traditional operating companies and other subsidiaries contributed $445 million to the qualified pension plan. No mandatory contributions to the qualified pension plan are anticipated for the year ending December 31, 2013. Southern Company also provides certain defined benefit pension plans for a selected group of management and highly compensated employees. Benefits under these non-qualified pension plans are funded on a cash basis. In addition, Southern Company provides certain medical care and life insurance benefits for retired employees through other postretirement benefit plans. The traditional operating companies fund related other postretirement trusts to the extent required by their respective regulatory commissions. For the year ending December 31, 2013, other postretirement trust contributions are expected to total approximately $28 million.

Actuarial Assumptions

The weighted average rates assumed in the actuarial calculations used to determine both the benefit obligations as of the measurement date and the net periodic costs for the pension and other postretirement benefit plans for the following year are presented below. Net periodic benefit costs were calculated in 2009 for the 2010 plan year using discount rates for the pension plans and the other postretirement benefit plans of 5.93% and 5.83%, respectively, and an annual salary increase of 4.18%.

	2012	2011	2010
Discount rate:			
Pension plans	**4.26%**	4.98%	5.52%
Other postretirement benefit plans	**4.05**	4.88	5.40
Annual salary increase	**3.59**	3.84	3.84
Long-term return on plan assets:			
Pension plans	**8.20**	8.45	8.45
Other postretirement benefit plans	**7.29**	7.39	7.40

The Company estimates the expected rate of return on pension plan and other postretirement benefit plan assets using a financial model to project the expected return on each current investment portfolio. The analysis projects an expected rate of return on each of seven different asset classes in order to arrive at the expected return on the entire portfolio relying on each trust's target asset allocation and reasonable capital market assumptions. The financial model is based on four key inputs: anticipated returns by asset class (based in part on historical returns), each trust's target asset allocation, an anticipated inflation rate, and the projected impact of a periodic rebalancing of each trust's portfolio.

An additional assumption used in measuring the accumulated other postretirement benefit obligations (APBO) is the weighted average medical care cost trend rate. The weighted average medical care cost trend rates used in measuring the APBO as of December 31, 2012 were as follows:

	Initial Cost Trend Rate	**Ultimate Cost Trend Rate**	**Year That Ultimate Rate Is Reached**
Pre-65	8.00%	5.00%	2020
Post-65 medical	6.00	5.00	2020
Post-65 prescription	6.00	5.00	2020

An annual increase or decrease in the assumed medical care cost trend rate of 1% would affect the APBO and the service and interest cost components at December 31, 2012 as follows:

	1 Percent Increase	1 Percent Decrease
	(in millions)	
Benefit obligation	$ 126	$ (106)
Service and interest costs	7	(6)

Pension Plans

The total accumulated benefit obligation for the pension plans was $8.5 billion at December 31, 2012 and $7.4 billion at December 31, 2011. Changes in the projected benefit obligations and the fair value of plan assets during the plan years ended December 31, 2012 and 2011 were as follows:

	2012	2011
	(in millions)	
Change in benefit obligation		
Benefit obligation at beginning of year	**$ 8,079**	$ 7,223
Service cost	**198**	184
Interest cost	**393**	389
Benefits paid	**(336)**	(324)
Actuarial loss	**968**	607
Balance at end of year	**9,302**	8,079
Change in plan assets		
Fair value of plan assets at beginning of year	**6,800**	6,834
Actual return (loss) on plan assets	**1,010**	256
Employer contributions	**479**	34
Benefits paid	**(336)**	(324)
Fair value of plan assets at end of year	**7,953**	6,800
Accrued liability	**$ (1,349)**	$ (1,279)

At December 31, 2012, the projected benefit obligations for the qualified and non-qualified pension plans were $8.7 billion and $582 million, respectively. All pension plan assets are related to the qualified pension plan.

Amounts recognized in the balance sheets at December 31, 2012 and 2011 related to the Company's pension plans consist of the following:

	2012	2011
	(in millions)	
Other regulatory assets, deferred	**$ 3,013**	$ 2,614
Other current liabilities	**(37)**	(34)
Employee benefit obligations	**(1,312)**	(1,245)
Accumulated OCI	**125**	109

Presented below are the amounts included in accumulated OCI and regulatory assets at December 31, 2012 and 2011 related to the defined benefit pension plans that had not yet been recognized in net periodic pension cost along with the estimated amortization of such amounts for 2013.

	Prior Service Cost	Net (Gain) Loss
	(in millions)	
Balance at December 31, 2012:		
Accumulated OCI	**$ 7**	**$ 118**
Regulatory assets	**100**	**2,913**
Total	**$ 107**	**$ 3,031**
Balance at December 31, 2011:		
Accumulated OCI	$ 7	$ 102
Regulatory assets	128	2,486
Total	$ 135	$ 2,588
Estimated amortization in net periodic pension cost in 2013:		
Accumulated OCI	$ 1	$ 8
Regulatory assets	26	192
Total	$ 27	$ 200

The components of OCI and the changes in the balance of regulatory assets related to the defined benefit pension plans for the years ended December 31, 2012 and 2011 are presented in the following table:

	Accumulated OCI	Regulatory Assets
	(in millions)	
Balance at December 31, 2010	$ 68	$ 1,749
Net (gain) loss	43	915
Change in prior service costs	—	1
Reclassification adjustments:		
Amortization of prior service costs	(1)	(31)
Amortization of net gain (loss)	(1)	(20)
Total reclassification adjustments	(2)	(51)
Total change	41	865
Balance at December 31, 2011	$ 109	$ 2,614
Net (gain) loss	**21**	**519**
Change in prior service costs	**—**	**—**
Reclassification adjustments:		
Amortization of prior service costs	**(1)**	**(29)**
Amortization of net gain (loss)	**(4)**	**(91)**
Total reclassification adjustments	**(5)**	**(120)**
Total change	**16**	**399**
Balance at December 31, 2012	**$ 125**	**$ 3,013**

Components of net periodic pension cost were as follows:

	2012	2011	2010
		(in millions)	
Service cost	**$ 198**	$ 184	$ 172
Interest cost	**393**	389	391
Expected return on plan assets	**(581)**	(607)	(552)
Recognized net loss	**95**	21	10
Net amortization	**30**	32	33
Net periodic pension cost	**$ 135**	$ 19	$ 54

Net periodic pension cost is the sum of service cost, interest cost, and other costs netted against the expected return on plan assets. The expected return on plan assets is determined by multiplying the expected rate of return on plan assets and the market-related value of plan assets. In determining the market-related value of plan assets, the Company has elected to amortize changes in the market value of all plan assets over five years rather than recognize the changes immediately. As a result, the accounting value of plan assets that is used to calculate the expected return on plan assets differs from the current fair value of the plan assets. Future benefit payments reflect expected future service and are estimated based on assumptions used to measure the projected benefit obligation for the pension plans. At December 31, 2012, estimated benefit payments were as follows:

	Benefit Payments
	(in millions)
2013	$ 376
2014	397
2015	419
2016	440
2017	465
2018 to 2022	2,632

Other Postretirement Benefits

Changes in the APBO and in the fair value of plan assets during the plan years ended December 31, 2012 and 2011 were as follows:

	2012	2011
	(in millions)	
Change in benefit obligation		
Benefit obligation at beginning of year	**$ 1,787**	$ 1,752
Service cost	**21**	21
Interest cost	**85**	92
Benefits paid	**(99)**	(103)
Actuarial loss	**71**	29
Plan amendments	**—**	(12)
Retiree drug subsidy	**7**	8
Balance at end of year	**1,872**	1,787
Change in plan assets		
Fair value of plan assets at beginning of year	**765**	802
Actual return on plan assets	**93**	4
Employer contributions	**55**	54
Benefits paid	**(92)**	(95)
Fair value of plan assets at end of year	**821**	765
Accrued liability	**$ (1,051)**	$ (1,022)

Amounts recognized in the balance sheets at December 31, 2012 and 2011 related to the Company's other postretirement benefit plans consist of the following:

	2012	2011
	(in millions)	
Other regulatory assets, deferred	**$ 360**	$ 345
Other current liabilities	**(3)**	(4)
Employee benefit obligations	**(1,048)**	(1,018)
Accumulated OCI	**7**	6

Presented below are the amounts included in accumulated OCI and regulatory assets at December 31, 2012 and 2011 related to the other postretirement benefit plans that had not yet been recognized in net periodic other postretirement benefit cost along with the estimated amortization of such amounts for 2013.

	Prior Service Cost	Net (Gain) Loss	Transition Obligation
		(in millions)	
Balance at December 31, 2012:			
Accumulated OCI	**$ —**	**$ 7**	**$ —**
Regulatory assets	**13**	**342**	**5**
Total	**$ 13**	**$ 349**	**$ 5**
Balance at December 31, 2011:			
Accumulated OCI	$ —	$ 6	$ —
Regulatory assets	17	314	14
Total	$ 17	$ 320	$ 14
Estimated amortization as net periodic postretirement benefit cost in 2013:			
Accumulated OCI	$ —	$ —	$ —
Regulatory assets	4	12	5
Total	$ 4	$ 12	$ 5

The components of OCI, along with the changes in the balance of regulatory assets, related to the other postretirement benefit plans for the plan years ended December 31, 2012 and 2011 are presented in the following table:

	Accumulated OCI	Regulatory Assets
	(in millions)	
Balance at December 31, 2010	$ 3	$ 292
Net (gain) loss	3	84
Change in prior service costs/transition obligation	—	(12)
Reclassification adjustments:		
Amortization of transition obligation	—	(10)
Amortization of prior service costs	—	(5)
Amortization of net gain (loss)	—	(4)
Total reclassification adjustments	—	(19)
Total change	3	53
Balance at December 31, 2011	$ 6	$ 345
Net (gain) loss	**1**	**35**
Change in prior service costs/transition obligation	—	—
Reclassification adjustments:		
Amortization of transition obligation	—	**(10)**
Amortization of prior service costs	—	**(4)**
Amortization of net gain (loss)	—	**(6)**
Total reclassification adjustments	—	**(20)**
Total change	**1**	**15**
Balance at December 31, 2012	**$ 7**	**$ 360**

Components of the other postretirement benefit plans' net periodic cost were as follows:

	2012	2011	2010
		(in millions)	
Service cost	$ 21	$ 21	$ 25
Interest cost	85	92	100
Expected return on plan assets	(60)	(64)	(63)
Net amortization	20	20	20
Net postretirement cost	$ 66	$ 69	$ 82

Future benefit payments, including prescription drug benefits, reflect expected future service and are estimated based on assumptions used to measure the APBO for the other postretirement benefit plans. Estimated benefit payments are reduced by drug subsidy receipts expected as a result of the Medicare Prescription Drug, Improvement, and Modernization Act of 2003 as follows:

	Benefit Payments	Subsidy Receipts	Total
		(in millions)	
2013	$ 110	$ (11)	$ 99
2014	116	(12)	104
2015	122	(13)	109
2016	127	(14)	113
2017	130	(16)	114
2018 to 2022	661	(88)	573

Benefit Plan Assets

Pension plan and other postretirement benefit plan assets are managed and invested in accordance with all applicable requirements, including ERISA and the Internal Revenue Code of 1986, as amended (Internal Revenue Code). The Company's investment policies for both the pension plan and the other postretirement benefit plans cover a diversified mix of assets, including equity and fixed income securities, real estate, and private equity. Derivative instruments are used primarily to gain efficient exposure to the various asset classes and as hedging tools. The Company minimizes the risk of large losses primarily through diversification but also monitors and manages other aspects of risk.

The composition of the Company's pension plan and other postretirement benefit plan assets as of December 31, 2012 and 2011, along with the targeted mix of assets for each plan, is presented below:

	Target	2012	2011
Pension plan assets:			
Domestic equity	26%	**28%**	29%
International equity	25	**24**	25
Fixed income	23	**27**	23
Special situations	3	**1**	—
Real estate investments	14	**13**	14
Private equity	9	**7**	9
Total	100%	**100%**	100%
Other postretirement benefit plan assets:			
Domestic equity	40%	**38%**	39%
International equity	21	**24**	18
Domestic fixed income	25	**28**	31
Global fixed income	4	**3**	4
Special situations	1	**—**	—
Real estate investments	6	**5**	5
Private equity	3	**2**	3
Total	100%	**100%**	100%

The investment strategy for plan assets related to the Company's qualified pension plan is to be broadly diversified across major asset classes. The asset allocation is established after consideration of various factors that affect the assets and liabilities of the pension plan including, but not limited to, historical and expected returns, volatility, correlations of asset classes, the current level of assets and liabilities, and the assumed growth in assets and liabilities. Because a significant portion of the liability of the pension plan is long-term in nature, the assets are invested consistent with long-term investment expectations for return and risk. To manage the actual asset class exposures relative to the target asset allocation, the Company employs a formal rebalancing program. As additional risk management, external investment managers and service providers are subject to written guidelines to ensure appropriate and prudent investment practices.

Investment Strategies

Detailed below is a description of the investment strategies for each major asset category for the pension and other postretirement benefit plans disclosed above:

- ***Domestic equity.*** A mix of large and small capitalization stocks with generally an equal distribution of value and growth attributes, managed both actively and through passive index approaches.
- ***International equity.*** A mix of growth stocks and value stocks with both developed and emerging market exposure, managed both actively and through passive index approaches.
- ***Fixed income.*** A mix of domestic and international bonds.
- ***Trust-owned life insurance (TOLI).*** Investments of the Company's taxable trusts aimed at minimizing the impact of taxes on the portfolio.
- ***Special situations.*** Investments in opportunistic strategies with the objective of diversifying and enhancing returns and exploiting short-term inefficiencies as well as investments in promising new strategies of a longer-term nature.
- ***Real estate investments.*** Investments in traditional private market, equity-oriented investments in real properties (indirectly through pooled funds or partnerships) and in publicly traded real estate securities.
- ***Private equity.*** Investments in private partnerships that invest in private or public securities typically through privately-negotiated and/or structured transactions, including leveraged buyouts, venture capital, and distressed debt.

Benefit Plan Asset Fair Values

Following are the fair value measurements for the pension plan and the other postretirement benefit plan assets as of December 31, 2012 and 2011. The fair values presented are prepared in accordance with GAAP. For purposes of determining the fair value of the pension plan and other postretirement benefit plan assets and the appropriate level designation, management relies on information provided by the plan's trustee. This information is reviewed and evaluated by management with changes made to the trustee information as appropriate.

Valuation methods of the primary fair value measurements disclosed in the following tables are as follows:

- **Investments in equity securities:** Investments in equity securities such as common stocks, American depositary receipts, and real estate investment trusts that trade on a public exchange are classified as Level 1 investments and are valued at the closing price in the active market. Equity investments with unpublished prices (i.e. pooled funds) are valued as Level 2, when the underlying holdings used to value the investment are comprised of Level 1 or Level 2 equity securities.
- **Investments in fixed income securities:** Investments in fixed income securities are generally classified as Level 2 investments and are valued based on prices reported in the market place. Additionally, the value of fixed income securities takes into consideration certain items such as broker quotes, spreads, yield curves, interest rates, and discount rates that apply to the term of a specific instrument.
- **Investments in TOLI**: Investments in TOLI policies are classified as Level 2 investments and are valued based on the underlying investments held in the policy's separate account. The underlying assets are equity and fixed income pooled funds that are comprised of Level 1 and Level 2 securities.
- **Investments in private equity and real estate:** Investments in private equity and real estate are generally classified as Level 3 as the underlying assets typically do not have observable inputs. The fund manager values the assets using various inputs and techniques depending on the nature of the underlying investments. In the case of private equity, techniques may include purchase multiples for comparable transactions, comparable public company trading multiples, and discounted cash flow analysis. Real estate managers generally use prevailing market capitalization rates, recent sales of comparable investments, and independent third-party appraisals to value underlying real estate investments. The fair value of partnerships is determined by aggregating the value of the underlying assets.

The fair values of pension plan assets as of December 31, 2012 and 2011 are presented below. These fair value measurements exclude cash, receivables related to investment income, pending investments sales, and payables related to pending investment purchases. Assets that are considered special situations investments, primarily real estate investments and private equities, are presented in the tables below based on the nature of the investment.

	Fair Value Measurements Using			
As of December 31, 2012:	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
		(in millions)		
Assets:				
Domestic equity*	$ 1,163	$ 670	$ —	$ 1,833
International equity*	912	979	—	1,891
Fixed income:				
U.S. Treasury, government, and agency bonds	—	516	—	516
Mortgage- and asset-backed securities	—	127	—	127
Corporate bonds	—	876	3	879
Pooled funds	—	399	—	399
Cash equivalents and other	5	548	—	553
Real estate investments	258	—	841	1,099
Private equity	—	—	593	593
Total	$ 2,338	$ 4,115	$ 1,437	$ 7,890

* Level 1 securities consist of actively traded stocks while Level 2 securities consist of pooled funds. Management believes that the portfolio is well-diversified with no significant concentrations of risk.

As of December 31, 2011:	Fair Value Measurements Using: Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
		(in millions)		
Assets:				
Domestic equity*	$ 1,155	$ 533	$ —	$ 1,688
International equity*	1,187	340	—	1,527
Fixed income:				
U.S. Treasury, government, and agency bonds	—	433	—	433
Mortgage- and asset-backed securities	—	135	—	135
Corporate bonds	—	832	3	835
Pooled funds	—	380	—	380
Cash equivalents and other	1	139	—	140
Real estate investments	220	—	782	1,002
Private equity	—	—	582	582
Total	$ 2,563	$ 2,792	$ 1,367	$ 6,722

* Level 1 securities consist of actively traded stocks while Level 2 securities consist of pooled funds. Management believes that the portfolio is well-diversified with no significant concentrations of risk.

Changes in the fair value measurement of the Level 3 items in the pension plan assets valued using significant unobservable inputs for the years ended December 31, 2012 and 2011 were as follows:

	2012		2011	
	Real Estate Investments	Private Equity	Real Estate Investments	Private Equity
		(in millions)		
Beginning balance	$ 782	$ 582	$ 674	$ 638
Actual return on investments:				
Related to investments held at year end	56	1	72	(12)
Related to investments sold during the year	3	41	20	47
Total return on investments	59	42	92	35
Purchases, sales, and settlements	—	(31)	16	(91)
Transfers into/out of Level 3	—	—	—	—
Ending balance	$ 841	$ 593	$ 782	$ 582

The fair values of other postretirement benefit plan assets as of December 31, 2012 and 2011 are presented below. These fair value measurements exclude cash, receivables related to investment income, pending investments sales, and payables related to pending investment purchases. Assets that are considered special situations investments, primarily real estate investments and private equities, are presented in the tables below based on the nature of the investment.

	Fair Value Measurements Using			
As of December 31, 2012:	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
		(in millions)		
Assets:				
Domestic equity*	$ 140	$ 43	$ —	$ 183
International equity*	33	75	—	108
Fixed income:				
U.S. Treasury, government, and agency bonds	—	24	—	24
Mortgage- and asset-backed securities	—	4	—	4
Corporate bonds	—	31	—	31
Pooled funds	—	42	—	42
Cash equivalents and other	—	44	—	44
Trust-owned life insurance	—	320	—	320
Real estate investments	10	—	30	40
Private equity	—	—	21	21
Total	$ 183	$ 583	$ 51	$ 817

* Level 1 securities consist of actively traded stocks while Level 2 securities consist of pooled funds. Management believes that the portfolio is well-diversified with no significant concentrations of risk.

As of December 31, 2011:	Fair Value Measurements Using: Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
		(in millions)		
Assets:				
Domestic equity*	$ 156	$ 38	$ —	$ 194
International equity*	45	39	—	84
Fixed income:				
U.S. Treasury, government, and agency bonds	—	24	—	24
Mortgage- and asset-backed securities	—	5	—	5
Corporate bonds	—	32	—	32
Pooled funds	—	48	—	48
Cash equivalents and other	—	46	—	46
Trust-owned life insurance	—	291	—	291
Real estate investments	9	—	30	39
Private equity	—	—	23	23
Total	$ 210	$ 523	$ 53	$ 786

* Level 1 securities consist of actively traded stocks while Level 2 securities consist of pooled funds. Management believes that the portfolio is well-diversified with no significant concentrations of risk.

Changes in the fair value measurement of the Level 3 items in the other postretirement benefit plan assets valued using significant unobservable inputs for the years ended December 31, 2012 and 2011 were as follows:

	2012		2011	
	Real Estate Investments	Private Equity	Real Estate Investments	Private Equity
		(in millions)		
Beginning balance	$ 30	$ 23	$ 26	$ 23
Actual return on investments:				
Related to investments held at year end	—	—	3	—
Related to investments sold during the year	—	1	1	2
Total return on investments	—	1	4	2
Purchases, sales, and settlements	—	(3)	—	(2)
Transfers into/out of Level 3	—	—	—	—
Ending balance	$ 30	$ 21	$ 30	$ 23

Employee Savings Plan

Southern Company also sponsors a 401(k) defined contribution plan covering substantially all employees. The Company provides an 85% matching contribution on up to 6% of an employee's base salary. Total matching contributions made to the plan for 2012, 2011, and 2010 were $82 million, $78 million, and $76 million, respectively.

3. CONTINGENCIES AND REGULATORY MATTERS

General Litigation Matters

Southern Company and its subsidiaries are subject to certain claims and legal actions arising in the ordinary course of business. In addition, the business activities of Southern Company's subsidiaries are subject to extensive governmental regulation related to public health and the environment, such as regulation of air emissions and water discharges. Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements such as air quality and water standards, has increased generally throughout the U.S. In particular, personal injury, property damage, and other claims for damages alleged to have been caused by carbon dioxide (CO_2) and other emissions, coal combustion byproducts, and alleged exposure to hazardous materials, and/or requests for injunctive relief in connection with such matters, have become more frequent. The ultimate outcome of such pending or potential litigation against Southern Company and its subsidiaries cannot be predicted at this time; however, for current proceedings not specifically reported herein, management does not anticipate that the ultimate liabilities, if any, arising from such current proceedings would have a material effect on Southern Company's financial statements.

Insurance Recovery

Mirant Corporation (Mirant) was an energy company with businesses that included independent power projects and energy trading and risk management companies in the U.S. and other countries. Mirant was a wholly-owned subsidiary of Southern Company until its initial public offering in 2000. In 2001, Southern Company completed a spin-off to its stockholders of its remaining ownership, and Mirant became an independent corporate entity.

In 2003, Mirant and certain of its affiliates filed voluntary petitions for relief under Chapter 11 of the Bankruptcy Code. In 2005, Mirant, as a debtor in possession, and the unsecured creditors' committee filed a complaint against Southern Company. Later in 2005, this complaint was transferred to MC Asset Recovery, LLC (MC Asset Recovery) as part of Mirant's plan of reorganization. In 2009, Southern Company entered into a settlement agreement with MC Asset Recovery to resolve this action. The settlement included an agreement where Southern Company paid MC Asset Recovery $202 million. Southern Company filed an insurance claim in 2009 to recover a portion of this settlement and received a nontaxable $25 million payment from its insurance provider on June 14, 2012. Additionally, legal fees related to this insurance settlement totaled approximately $6 million. As a result, the net reduction to expense presented as MC Asset Recovery insurance settlement in the statement of income was approximately $19 million.

Environmental Matters

New Source Review Actions

In 1999, the EPA brought a civil action in the U.S. District Court for the Northern District of Georgia against certain Southern Company subsidiaries, including Alabama Power and Georgia Power, alleging that these subsidiaries had violated the New Source Review (NSR) provisions of the Clean Air Act and related state laws at certain coal-fired generating facilities. The EPA alleged NSR violations at five coal-fired generating facilities operated by Alabama Power, including a unit co-owned by Mississippi Power, and three coal-fired generating facilities operated by Georgia Power, including a unit co-owned by Gulf Power. The civil action sought penalties and injunctive relief, including an order requiring installation of the best available control technology at the affected units. The case against Georgia Power (including claims related to the unit co-owned by Gulf Power) was administratively closed in 2001 and has not been reopened. After Alabama Power was dismissed from the original action, the EPA filed a separate action in 2001 against Alabama Power (including claims related to the unit co-owned by Mississippi Power) in the U.S. District Court for the Northern District of Alabama.

In 2006, the U.S. District Court for the Northern District of Alabama entered a consent decree, resolving claims relating to the alleged NSR violations at Plant Miller. In 2010, the EPA dismissed five of its eight remaining claims against Alabama Power, leaving only three claims, including one relating to the unit co-owned by Mississippi Power. In March 2011, the U.S. District Court for the Northern District of Alabama granted Alabama Power summary judgment on all remaining claims and dismissed the case with prejudice. That judgment is on appeal to the U.S. Court of Appeals for the Eleventh Circuit. On February 23, 2012, the EPA filed a motion in the U.S. District Court for the Northern District of Alabama seeking vacatur of the judgment and recusal of the judge in the case involving Alabama Power.

Southern Company believes the traditional operating companies complied with applicable laws and regulations in effect at the time the work in question took place. The Clean Air Act authorizes maximum civil penalties of $25,000 to $37,500 per day, per violation, depending on the date of the alleged violation. An adverse outcome could require substantial capital expenditures that cannot be determined at this time and could possibly require payment of substantial penalties. Such expenditures could affect future results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates. The ultimate outcome of these matters cannot be determined at this time.

Climate Change Litigation

Kivalina Case

In 2008, the Native Village of Kivalina and the City of Kivalina filed a lawsuit in the U.S. District Court for the Northern District of California against several electric utilities (including Southern Company), several oil companies, and a coal company. The plaintiffs allege that the village is being destroyed by erosion allegedly caused by global warming that the plaintiffs attribute to emissions of greenhouse gases by the defendants. The plaintiffs assert claims for public and private nuisance and contend that some of the defendants (including Southern Company) acted in concert and are therefore jointly and severally liable for the plaintiffs' damages. The suit seeks damages for lost property values and for the cost of relocating the village, which is alleged to be $95 million to $400 million. In 2009, the U.S. District Court for the Northern District of California granted the defendants' motions to dismiss the case. On September 21, 2012, the U.S. Court of Appeals for the Ninth Circuit upheld the U.S. District Court for the Northern District of California's dismissal of the case. On November 27, 2012, the U.S. Court of Appeals for the Ninth Circuit denied the plaintiffs' request for review of the decision. On February 25, 2013, the plaintiffs filed a petition for writ of certiorari with the U.S. Supreme Court. Southern Company believes that these claims are without merit. While Southern Company believes the likelihood of loss is remote based on existing case law, it is not possible to predict with certainty whether Southern Company will incur any liability in connection with this matter. The ultimate outcome of this matter cannot be determined at this time.

Hurricane Katrina Case

In 2005, immediately following Hurricane Katrina, a lawsuit was filed in the U.S. District Court for the Southern District of Mississippi by Ned Comer on behalf of Mississippi residents seeking recovery for property damage and personal injuries caused by Hurricane Katrina. In 2006, the plaintiffs amended the complaint to include Southern Company and many other electric utilities, oil companies, chemical companies, and coal producers. The plaintiffs allege that the defendants contributed to climate change, which contributed to the intensity of Hurricane Katrina. In 2007, the U.S. District Court for the Southern District of Mississippi dismissed the case. On appeal to the U.S. Court of Appeals for the Fifth Circuit, a three-judge panel reversed the U.S. District Court for the Southern District of Mississippi, holding that the case could proceed, but, on rehearing, the full U.S. Court of Appeals for the Fifth Circuit dismissed the plaintiffs' appeal, resulting in reinstatement of the decision of the U.S. District Court for the Southern District of Mississippi in favor of the defendants. In May 2011, the plaintiffs filed an amended version of their class action complaint, arguing that the earlier dismissal was on procedural grounds and under Mississippi law the plaintiffs have a right to re-file. The amended complaint was also filed against numerous chemical, coal, oil, and utility companies, including Alabama Power, Georgia Power, Gulf Power, and Southern Power. On March 20, 2012, the U.S. District Court for the Southern District of Mississippi dismissed the plaintiffs' amended complaint. On April 16, 2012, the plaintiffs appealed the case to the U.S. Court of Appeals for the Fifth Circuit. Southern Company believes that these claims are without merit. While Southern Company believes the likelihood of loss is remote based on existing case law, it is not possible to predict with certainty whether the Company will incur any liability in connection with this matter. The ultimate outcome of this matter cannot be determined at this time.

Environmental Remediation

The Southern Company system must comply with environmental laws and regulations that cover the handling and disposal of waste and releases of hazardous substances. Under these various laws and regulations, the Southern Company system could incur substantial costs to clean up properties. The traditional operating companies have each received authority from their respective state PSCs to recover approved environmental compliance costs through regulatory mechanisms. These rates are adjusted annually or as necessary within limits approved by the state PSCs.

Georgia Power's environmental remediation liability as of December 31, 2012 was $19 million. Georgia Power has been designated or identified as a potentially responsible party (PRP) at sites governed by the Georgia Hazardous Site Response Act and/or by the federal Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA), including a large site in Brunswick, Georgia on the CERCLA National Priorities List (NPL). The parties have completed the removal of wastes from the Brunswick site as ordered by the EPA. Additional cleanup and claims for recovery of natural resource damages at this site or for the assessment and potential cleanup of other sites on the Georgia Hazardous Sites Inventory and the CERCLA NPL

are anticipated.

Georgia Power and numerous other entities have been designated by the EPA as PRPs at the Ward Transformer Superfund site located in Raleigh, North Carolina. In September 2011, the EPA issued a Unilateral Administrative Order (UAO) to Georgia Power and 22 other parties, ordering specific remedial action of certain areas at the site. In November 2011, Georgia Power filed a response with the EPA stating it has sufficient cause to believe it is not a liable party under CERCLA. The EPA notified Georgia Power in November 2011 that it is considering enforcement options against Georgia Power and other non-complying UAO recipients. If the court determines that a respondent failed to comply with the UAO without sufficient cause, the EPA may also seek civil penalties of up to $37,500 per day for the violation and punitive damages of up to three times the costs incurred by the EPA as a result of the party's failure to comply with the UAO.

In addition to the EPA's action at this site, Georgia Power, along with many other parties, was sued in a private action by several existing PRPs for cost recovery related to the removal action. On February 1, 2013, the court granted Georgia Power's summary judgment motion ruling that Georgia Power has no liability in the private action. The plaintiffs may appeal the court's order to the U.S. Court of Appeals for the Fourth Circuit.

The ultimate outcome of these matters will depend upon the success of defenses asserted, the ultimate number of PRPs participating in the cleanup, and numerous other factors and cannot be determined at this time; however, as a result of the regulatory treatment, these matters are not expected to have a material impact on Southern Company's financial statements.

Gulf Power's environmental remediation liability includes estimated costs of environmental remediation projects of approximately $61 million as of December 31, 2012. These estimated costs relate to site closure criteria by the Florida Department of Environmental Protection (FDEP) for potential impacts to soil and groundwater from herbicide applications at Gulf Power substations. The schedule for completion of the remediation projects will be subject to FDEP approval. The projects have been approved by the Florida PSC for recovery through Gulf Power's environmental cost recovery clause; therefore, there was no impact on net income as a result of these estimates.

The final outcome of these matters cannot be determined at this time. However, based on the currently known conditions at these sites and the nature and extent of activities relating to these sites, management does not believe that additional liabilities, if any, at these sites would be material to the financial statements.

Nuclear Fuel Disposal Costs

Acting through the U.S. Department of Energy (DOE) and pursuant to the Nuclear Waste Policy Act of 1982, the U.S. government entered into contracts with Alabama Power and Georgia Power that require the DOE to dispose of spent nuclear fuel and high level radioactive waste generated at Plants Hatch and Farley and Plant Vogtle Units 1 and 2. The DOE failed to timely perform and has yet to commence the performance of its contractual and statutory obligation to dispose of spent nuclear fuel beginning no later than January 31, 1998. Consequently, Alabama Power and Georgia Power have pursued and continue to pursue legal remedies against the U.S. government for its partial breach of contract.

As a result of the first lawsuit, Georgia Power recovered approximately $27 million, based on its ownership interests, and Alabama Power recovered approximately $17 million, representing substantially all of the Southern Company system's direct costs of the expansion of spent nuclear fuel storage facilities at Plants Farley and Hatch and Plant Vogtle Units 1 and 2 from 1998 through 2004.

In 2008, Alabama Power and Georgia Power filed a second lawsuit against the U.S. government for the costs of continuing to store spent nuclear fuel at Plants Farley and Hatch and Plant Vogtle Units 1 and 2. Damages are being sought for the period from January 1, 2005 through December 31, 2010. Damages will continue to accrue until the issue is resolved or storage is provided. No amounts have been recognized in the financial statements as of December 31, 2012 for any potential recoveries from the second lawsuit. The final outcome of these matters cannot be determined at this time; however, no material impact on Southern Company's net income is expected.

Sufficient pool storage capacity for spent fuel is available at Plant Vogtle Units 1 and 2 to maintain full-core discharge capability for both units into 2014. Construction of an on-site dry storage facility at Plant Vogtle Units 1 and 2 has begun. The facility is expected to begin operation in sufficient time to maintain full-core discharge capability, with additional on-site dry storage to be added as needed. At Plants Hatch and Farley, on-site dry spent fuel storage facilities are operational and can be expanded to accommodate spent fuel through the expected life of each plant.

Retail Regulatory Matters

Alabama Power

Retail Rate Adjustments

In July 2011, the Alabama PSC issued an order to eliminate a tax-related adjustment under Alabama Power's rate structure effective with October 2011 billings. The elimination of this adjustment resulted in additional revenues of approximately $31 million for 2011. In accordance with the order, Alabama Power made additional accruals to the natural disaster reserve (NDR) in the fourth quarter 2011 of an amount equal to such additional 2011 revenues. The NDR was impacted as a result of operations and maintenance expenses incurred in connection with the April 2011 storms in Alabama. See "Natural Disaster Reserve" below for additional information. The elimination of this adjustment resulted in additional revenues of approximately $106 million for 2012.

Rate RSE

Alabama Power operates under a rate stabilization and equalization plan (Rate RSE) approved by the Alabama PSC. Alabama Power's Rate RSE adjustments are based on forward-looking information for the applicable upcoming calendar year. Rate adjustments for any two-year period, when averaged together, cannot exceed 4.0% and any annual adjustment is limited to 5.0%. Retail rates remain unchanged when the retail return on common equity (ROE) is projected to be between 13.0% and 14.5%. If Alabama Power's actual retail ROE is above the allowed equity return range, customer refunds will be required; however, there is no provision for additional customer billings should the actual retail ROE fall below the allowed equity return range.

In 2011 and 2012, retail rates under Rate RSE remained unchanged from 2010. On November 30, 2012, Alabama Power made its Rate RSE submission to the Alabama PSC of projected data for calendar year 2013; projected earnings were within the specified return range, and, therefore, retail rates under Rate RSE remained unchanged for 2013. Under the terms of Rate RSE, the maximum possible increase for 2014 is 5.00%. However, Alabama Power is working with the Alabama PSC to develop a plan that will potentially preclude the need for a Rate RSE increase in 2014. The ultimate outcome of this matter cannot be determined at this time.

Rate CNP

Alabama Power's retail rates, approved by the Alabama PSC, provide for adjustments to recognize the placing of new generating facilities into retail service under rate certificated new plant (Rate CNP). Alabama Power may also recover retail costs associated with certificated PPAs under rate certificated new plant (Rate CNP PPA). Effective April 2011, Rate CNP PPA was reduced by approximately $5 million annually. On March 6, 2012, the Alabama PSC issued a consent order that Alabama Power leave in effect the current Rate CNP PPA factor for billings for the period April 1, 2012 through March 31, 2013. It is anticipated that no adjustment will be made to Rate CNP PPA in 2013. As of December 31, 2012, Alabama Power had an under recovered certificated PPA balance of $9 million, $7 million of which is included in deferred under recovered regulatory clause revenues and $2 million of which is included in under recovered regulatory clause revenues in the balance sheet.

On September 17, 2012, the Alabama PSC approved and certificated a PPA for the purchase of approximately 200 megawatts (MWs) of the approximately 400 MWs of energy from wind-powered generating facilities and all associated environmental attributes, including renewable energy credits. The terms of this PPA and a previously approved and certificated PPA permit Alabama Power to use the energy and retire the associated environmental attributes in service of its customers or to sell environmental attributes, separately or bundled with energy, to third parties. Approximately 200 MWs of energy from wind-powered generating facilities was operational in December 2012.

Alabama Power's retail rates, approved by the Alabama PSC also allow for the recovery of Alabama Power's retail costs associated with environmental laws, regulations, or other such mandates (Rate CNP Environmental). Rate CNP Environmental is based on forward-looking information and provides for the recovery of these costs pursuant to a factor that is calculated annually. Environmental costs to be recovered include operations and maintenance expenses, depreciation, and a return on certain invested capital. There was no adjustment to Rate CNP Environmental to recover environmental costs in 2011 or 2012. On November 26, 2012, Alabama Power submitted calculations associated with its cost of complying with environmental mandates, as provided under Rate CNP Environmental. The filing reflected a projected unrecovered retail revenue requirement for environmental compliance of less than $1 million, which is to be recovered in the billing months of January 2013 through December 2013. On December 4, 2012, the Alabama PSC issued a consent order that Alabama Power leave in effect for 2013 the factors associated with Alabama Power's environmental compliance costs for the year 2012. Any unrecovered amounts associated with 2013 will be reflected in the 2014 filing. As of December 31, 2012, Alabama Power had an under recovered environmental clause balance of $21 million which is included in under recovered regulatory clause revenues in the balance sheet.

Environmental Accounting Order

Proposed and final environmental regulations could result in significant additional compliance costs that could affect future unit retirement and replacement decisions. In September 2011, the Alabama PSC approved an order allowing for the establishment of a regulatory asset to record the unrecovered investment costs associated with any such decisions, including the unrecovered plant asset balance and the unrecovered costs associated with site removal and closure. These costs would be amortized over the affected unit's remaining useful life, as established prior to the decision regarding early retirement.

Compliance and Pension Cost Accounting Order

On November 6, 2012, the Alabama PSC approved an accounting order for certain compliance-related operation and maintenance expenditures for the years 2013 through 2017, as well as the incremental increase in operation expense related to pension cost for 2013. Under the accounting order, expenses from January 2013 through December 2017 related to compliance with standards addressing Critical Infrastructure Protection issued by the North American Electric Reliability Corporation and cyber security requirements issued by the NRC will be deferred to a regulatory asset account and amortized over a three-year period beginning in January 2015. Expenses from January 2013 through December 2017 related to compliance with NRC guidance addressing the readiness at nuclear facilities within the U.S., as prompted by the earthquake and tsunami that struck Japan in March 2011, also will be deferred as a regulatory asset and recovered over the same amortization period. The compliance-related expenses to be afforded regulatory asset treatment over the five-year period are currently estimated to be approximately $43 million. In addition, the accounting order authorizes Alabama Power to defer an incremental increase in its pension cost for 2013. That increased pension cost is estimated to be approximately $17 million. During 2013, the actual incremental increase will be deferred to a regulatory asset account and will be amortized over a three-year period beginning in January 2015. Pursuant to the accounting order, Alabama Power has the ability to accelerate the amortization of the regulatory assets.

Energy Cost Recovery

Alabama Power has established energy cost recovery rates under Alabama Power's energy cost recovery rate (Rate ECR) as approved by the Alabama PSC. Rates are based on an estimate of future energy costs and the current over or under recovered balance. Revenues recognized under Rate ECR and recorded on the financial statements are adjusted for the difference in actual recoverable fuel costs and amounts billed in current regulated rates. The difference in the recoverable fuel costs and amounts billed give rise to the over or under recovered amounts recorded as regulatory assets or liabilities. Alabama Power, along with the Alabama PSC, continually monitors the over or under recovered cost balance to determine whether an adjustment to billing rates is required. Changes in the Rate ECR factor have no significant effect on net income, but will impact operating cash flows. Currently, the Alabama PSC may approve billing rates under Rate ECR of up to 5.910 cents per kilowatt hour (KWH). On December 4, 2012, the Alabama PSC issued a consent order that Alabama Power leave in effect the energy cost recovery rates which began in April 2011 for 2013. Therefore, the Rate ECR factor as of January 1, 2013 remained at 2.681 cents per KWH. Effective with billings beginning in January 2014, the Rate ECR factor will be 5.910 cents per KWH, absent a further order from the Alabama PSC.

As of December 31, 2012 and 2011, Alabama Power had under recovered fuel balances of approximately $4 million and $31 million, respectively, which are included in deferred under recovered regulatory clause revenues in the balance sheets. This classification is based on estimates, which include such factors as weather, generation availability, energy demand, and the price of energy. A change in any of these factors could have a material impact on the timing of any recovery of the under recovered fuel costs.

Natural Disaster Reserve

Based on an order from the Alabama PSC, Alabama Power maintains a reserve for operations and maintenance expenses to cover the cost of damages from major storms to its transmission and distribution facilities. The order approves a separate monthly Rate Natural Disaster Reserve (Rate NDR) charge to customers consisting of two components. The first component is intended to establish and maintain a reserve balance for future storms and is an on-going part of customer billing. The second component of the Rate NDR charge is intended to allow recovery of any existing deferred storm-related operations and maintenance costs and any future reserve deficits over a 24-month period. The Alabama PSC order gives Alabama Power authority to record a deficit balance in the NDR when costs of storm damage exceed any established reserve balance. Alabama Power has the authority, based on an order from the Alabama PSC, to accrue certain additional amounts as circumstances warrant. The order allows for reliability-related expenditures to be charged against the additional accruals when the NDR balance exceeds $75 million. Alabama Power may designate a portion of the NDR to reliability-related expenditures as a part of an annual budget process for the following year or during the current year for identified unbudgeted reliability-related expenditures that are incurred. Accruals that have not been designated can be used to offset storm charges. Additional accruals to the NDR will

enhance Alabama Power's ability to deal with the financial effects of future natural disasters, promote system reliability, and offset costs retail customers would otherwise bear.

As revenue from the Rate NDR charge is recognized, an equal amount of operations and maintenance expenses related to the NDR will also be recognized. As a result, the Rate NDR charge will not have an effect on net income but will impact operating cash flows.

During the first half of 2011, multiple storms caused varying degrees of damage to Alabama Power's transmission and distribution facilities. The most significant storms occurred in April 2011, causing over 400,000 of Alabama Power's 1.4 million customers to be without electrical service. The cost of repairing the damage to facilities and restoring electrical service to customers as a result of these storms was $42 million for operations and maintenance expenses and $161 million for capital-related expenditures.

In accordance with the order that was issued by the Alabama PSC in July 2011 to eliminate a tax-related adjustment under Alabama Power's rate structure that resulted in additional revenues, Alabama Power made additional accruals to the NDR in the fourth quarter 2011 of an amount equal to the additional 2011 revenues, which were approximately $31 million.

The accumulated balances in the NDR for the years ended December 31, 2012 and December 31, 2011 were approximately $103 million and $110 million, respectively. Any accruals to the NDR are included in the balance sheets under other regulatory liabilities, deferred and are reflected as other operations and maintenance expenses in the statements of income.

Nuclear Outage Accounting Order

In 2010, the Alabama PSC approved a change to the nuclear maintenance outage accounting process associated with routine refueling activities. Previously, Alabama Power accrued nuclear outage operations and maintenance expenses for the two units at Plant Farley during the 18-month cycle for the outages. In accordance with the 2010 order, nuclear outage expenses are deferred when the charges actually occur and then amortized over the subsequent 18-month period.

The initial result of implementation of the accounting order was that no nuclear maintenance outage expenses were recognized from January 2011 through December 2011, which decreased nuclear outage operations and maintenance expenses in 2011 from 2010 by approximately $50 million. During the fall of 2011, approximately $38 million of actual nuclear outage expenses associated with one unit at Plant Farley was deferred to a regulatory asset account; beginning in January 2012, these deferred costs are being amortized to nuclear operations and maintenance expenses over an 18-month period. During the spring of 2012, approximately $31 million of actual nuclear outage expenses associated with the second unit at Plant Farley was deferred to a regulatory asset account; beginning in July 2012, these deferred costs are being amortized to nuclear operations and maintenance expenses over an 18-month period. Alabama Power will continue the pattern of deferral of nuclear outage expenses as incurred and the recognition of expenses over a subsequent 18-month period pursuant to the existing order.

Georgia Power

Rate Plans

The economic recession significantly reduced Georgia Power's revenues upon which retail rates were set by the Georgia PSC for 2008 through 2010 (2007 Retail Rate Plan). In 2009, despite stringent efforts to reduce expenses, Georgia Power's projected retail ROE for both 2009 and 2010 was below 10.25%. However, in lieu of a full base rate case to increase customer rates as allowed under the 2007 Retail Rate Plan, in 2009, the Georgia PSC approved Georgia Power's request for an accounting order. Under the terms of the accounting order, Georgia Power could amortize up to $108 million of the regulatory liability related to other cost of removal obligations in 2009 and up to $216 million in 2010, limited to the amount needed to earn no more than a 9.75% and 10.15% retail ROE in 2009 and 2010, respectively. For the years ended December 31, 2009 and 2010, Georgia Power amortized $41 million and $174 million, respectively, of the regulatory liability related to other cost of removal obligations.

In 2010, the Georgia PSC approved the 2010 ARP, which became effective January 1, 2011. The terms of the 2010 ARP reflect a settlement agreement among Georgia Power, the Georgia PSC Public Interest Advocacy Staff, and eight other intervenors. Under the terms of the 2010 ARP, Georgia Power is amortizing approximately $92 million of its remaining regulatory liability related to other cost of removal obligations over the three years ending December 31, 2013.

Also under the terms of the 2010 ARP, effective January 1, 2011, Georgia Power increased its (1) traditional base tariff rates by approximately $347 million; (2) Demand-Side Management (DSM) tariff rates by approximately $31 million; (3) environmental compliance cost recovery tariff rate by approximately $168 million; and (4) Municipal Franchise Fee (MFF) tariff rate by approximately $16 million, for a total increase in base revenues of approximately $562 million.

Under the 2010 ARP, the following additional base rate adjustments have been made to Georgia Power's tariffs in 2012 and 2013:

- Effective January 1, 2012 and 2013, the DSM tariffs increased by $17 million and $14 million, respectively;
- Effective April 1, 2012 and January 1, 2013, the traditional base tariffs increased by an estimated $122 million and $58 million, respectively, to recover the revenue requirements for Plant McDonough-Atkinson Units 4, 5, and 6 for the period through December 31, 2013; and
- The MFF tariff increased consistently with the adjustments above, as well as those related to the interim fuel rider (IFR) and Nuclear Construction Cost Recovery (NCCR) tariff adjustments described herein under "Fuel Cost Recovery" and "Nuclear Construction."

Under the 2010 ARP, Georgia Power's allowed retail ROE is set at 11.15%, and earnings will be evaluated against a retail ROE range of 10.25% to 12.25%. Two-thirds of any earnings above 12.25% will be directly refunded to customers, with the remaining one-third retained by Georgia Power. There were no refunds related to earnings for 2011 or 2012. Georgia Power is required to file a general base rate case by July 1, 2013, in response to which the Georgia PSC would be expected to determine whether the 2010 ARP should be continued, modified, or discontinued.

Integrated Resource Plans

On March 20, 2012, the Georgia PSC approved Georgia Power's request to decertify and retire Plant Branch Units 1 and 2 as of December 31, 2013 and October 31, 2013, the compliance dates for the respective units under the Georgia Multi-Pollutant Rule, and an oil-fired unit at Plant Mitchell as of March 26, 2012, as requested in the 2011 Integrated Resource Plan (IRP). The Georgia PSC also approved three PPAs totaling 998 MWs with Southern Power for capacity and energy that will commence in 2015 and end in 2030. On November 21, 2012, the FERC accepted the PPAs.

Separately, on March 20, 2012, the Georgia PSC certified 495 MWs of wholesale capacity to be returned to retail service in 2015 and 2016 under a 2010 agreement, subject to the decertification of any related generating units including 243 MWs of the 16 units described below.

On January 31, 2013, Georgia Power filed its triennial IRP (2013 IRP). The filing included Georgia Power's request to decertify 16 coal- and oil-fired units totaling 2,093 MWs. Several factors, including the cost to comply with existing and future environmental regulations, recent and forecasted economic conditions, and lower natural gas prices, contributed to the decision to close these units.

Georgia Power requested the decertification of Plant Boulevard Units 2 and 3 (28 MWs) upon approval of the 2013 IRP and the decertification of Plant Bowen Unit 6 (32 MWs) by April 16, 2013. Plant Branch Units 3 and 4 (1,016 MWs), Plant Yates Units 1 through 5 (579 MWs), and Plant McManus Units 1 and 2 (122 MWs) will be retired by April 16, 2015, the compliance date of the Mercury and Air Toxics Standards (MATS) rule. Georgia Power has also requested a revision to the decertification date of Plant Branch Unit 1 from December 31, 2013 to April 16, 2015. To allow for necessary transmission reliability improvements, Georgia Power expects to seek a one-year extension of the MATS rule compliance date for Plant Kraft Units 1 through 4 (316 MWs) and to retire these units by April 16, 2016.

The filing also included Georgia Power's request to switch the primary fuel source for Plant Yates Units 6 and 7 from coal to natural gas. Additionally, Georgia Power plans to switch the primary fuel source for Plant McIntosh Unit 1 from Central Appalachian coal to Powder River Basin (PRB) coal following further evaluation, including a successful test burn of the PRB fuel.

Under the terms of the 2010 ARP, any costs associated with changes to Georgia Power's approved environmental operating or capital budgets resulting from new or revised environmental regulations through 2013 that are approved by the Georgia PSC in connection with an updated IRP will be deferred as a regulatory asset to be recovered over a time period deemed appropriate by the Georgia PSC. In connection with the retirement decisions, Georgia Power reclassified the retail portion of the net carrying value of Plant Branch Units 1 through 4 from plant in service, net of depreciation, to other utility plant, net. Georgia Power is continuing to depreciate these units using the current composite straight-line rates previously approved by the Georgia PSC. Upon actual retirement, the Georgia PSC approved the continued deferral and amortization of the remaining net carrying values for Plant Branch Units 1 and 2 in its order for the 2011 IRP and Georgia Power has requested similar treatment for Plant Branch Units 3 and 4 in the 2013 IRP. Georgia Power also reclassified the construction work in progress (CWIP) balances totaling $65 million related to environmental controls for Plant Branch Units 1 through 4 and Plant Yates Units 6 and 7 that will not be completed as a result of the retirement decisions to regulatory assets and ceased accruing AFUDC. The Georgia PSC approved a three-year amortization period beginning January 2014 for the $13 million balance relating to Plant Branch Units 1 and 2 in its order for the 2011 IRP and Georgia Power has requested similar treatment for the balances related to Plant Branch Units 3 and 4 and Plant Yates Units 6 and 7 in the 2013 IRP. Georgia Power has also requested that the Georgia PSC approve the deferral of the

costs associated with material and supplies remaining at the unit retirement dates to a regulatory asset, to be amortized over a time period deemed appropriate by the Georgia PSC. As a result of this regulatory treatment, the decertification of these units is not expected to have a material impact on Southern Company's financial statements. The Georgia PSC is scheduled to vote on the 2013 IRP by July 2013.

Fuel Cost Recovery

Georgia Power has established fuel cost recovery rates approved by the Georgia PSC. The Georgia PSC approved reductions in Georgia Power's total annual billings of approximately $43 million effective June 1, 2011, $567 million effective June 1, 2012, and $122 million effective January 1, 2013. In addition, the Georgia PSC has authorized an IFR, which allows Georgia Power to adjust its fuel cost recovery rates prior to the next fuel case if the under or over recovered fuel balance exceeds $215 million through February 2013 and $200 million thereafter. Georgia Power's fuel cost recovery includes costs associated with a natural gas hedging program as revised and approved by the Georgia PSC on February 7, 2013, requiring it to use options and hedges within a 24-month time horizon. Georgia Power expects to file its next fuel case by March 1, 2014.

Georgia Power's over recovered fuel balance totaled approximately $230 million at December 31, 2012 and is included in current liabilities and other deferred credits and liabilities.

Fuel cost recovery revenues as recorded on the financial statements are adjusted for differences in actual recoverable fuel costs and amounts billed in current regulated rates. Accordingly, changes in the billing factor will not have a significant effect on Southern Company's revenues or net income, but will affect cash flow.

Storm Damage Recovery

Georgia Power defers and recovers certain costs related to damages from major storms as mandated by the Georgia PSC. As of December 31, 2012, the balance in the regulatory asset related to storm damage was $38 million. As a result of this regulatory treatment, the costs related to storms are generally not expected to have a material impact on Southern Company's financial statements.

Nuclear Construction

In 2008, Georgia Power, acting for itself and as agent for Oglethorpe Power Corporation (OPC), the Municipal Electric Authority of Georgia (MEAG Power), and the City of Dalton, Georgia (Dalton), acting by and through its Board of Water, Light, and Sinking Fund Commissioners (collectively, Owners), entered into an agreement (Vogtle 3 and 4 Agreement) with a consortium consisting of Westinghouse Electric Company LLC (Westinghouse) and Stone & Webster, Inc. (collectively, Contractor), pursuant to which the Contractor agreed to design, engineer, procure, construct, and test two AP1000 nuclear units (with electric generating capacity of approximately 1,100 MWs each) and related facilities at Plant Vogtle (Plant Vogtle Units 3 and 4). Under the terms of the Vogtle 3 and 4 Agreement, the Owners agreed to pay a purchase price that is subject to certain price escalations and adjustments, including fixed escalation amounts and index-based adjustments, as well as adjustments for change orders, and performance bonuses for early completion and unit performance. Each Owner is severally (and not jointly) liable for its proportionate share, based on its ownership interest, of all amounts owed to the Contractor under the Vogtle 3 and 4 Agreement. Georgia Power's proportionate share is 45.7%. The Vogtle 3 and 4 Agreement provides for liquidated damages upon the Contractor's failure to fulfill the schedule and performance guarantees. The Contractor's liability to the Owners for schedule and performance liquidated damages and warranty claims is subject to a cap.

Certain payment obligations of Westinghouse and Stone & Webster, Inc. under the Vogtle 3 and 4 Agreement are guaranteed by Toshiba Corporation and The Shaw Group, Inc., respectively. In the event of certain credit rating downgrades of any Owner, such Owner will be required to provide a letter of credit or other credit enhancement. The Owners may terminate the Vogtle 3 and 4 Agreement at any time for their convenience, provided that the Owners will be required to pay certain termination costs and, at certain stages of the work, cancellation fees to the Contractor. The Contractor may terminate the Vogtle 3 and 4 Agreement under certain circumstances, including certain Owner suspension or delays of work, action by a governmental authority to permanently stop work, certain breaches of the Vogtle 3 and 4 Agreement by the Owners, Owner insolvency, and certain other events.

In 2009, the Georgia PSC originally certified construction costs of $6.4 billion to place Plant Vogtle Units 3 and 4 into service in April 2016 and April 2017, respectively, and approved inclusion of the related CWIP accounts in rate base. Also in 2009, the State of Georgia enacted the Georgia Nuclear Energy Financing Act, which allows Georgia Power to recover financing costs for nuclear construction projects through annual adjustments to an NCCR tariff by including the related CWIP accounts in rate base during the construction period. With respect to Plant Vogtle Units 3 and 4, this legislation allowed Georgia Power, beginning in 2011, to recover an estimated $1.7 billion of related financing costs during the construction period. As a result, in 2009, the Georgia PSC also revised the certified in-service capital cost to approximately $4.4 billion.

The Georgia PSC approved increases to the NCCR tariff of approximately $223 million, $35 million, and $50 million, effective January 1, 2011, 2012, and 2013, respectively. Through the NCCR tariff, Georgia Power is collecting and amortizing to earnings approximately $91 million of financing costs, capitalized in 2009 and 2010, over the five-year period ending December 31, 2015, in addition to the ongoing financing costs. At December 31, 2012, approximately $55 million of these 2009 and 2010 costs remained unamortized in CWIP. At December 31, 2012, Georgia Power's CWIP balance for Plant Vogtle Units 3 and 4 totaled $2.3 billion.

In 2009, the NRC issued an Early Site Permit and Limited Work Authorization which allowed limited work to begin on Plant Vogtle Units 3 and 4. The NRC certified the Westinghouse Design Control Document, as amended (DCD), for the AP1000 nuclear reactor design, effective December 30, 2011, and issued combined construction and operating licenses (COLs) on February 10, 2012. Receipt of the COLs allowed full construction to begin.

On February 16, 2012, separate groups of petitioners filed petitions in the U.S. Court of Appeals for the District of Columbia Circuit seeking judicial review of the NRC's issuance of the COLs and certification of the DCD. These petitions were consolidated on April 3, 2012. On April 18, 2012, another group of petitioners filed a motion to stay the effectiveness of the COLs with the U.S. District Court for the District of Columbia. On July 11, 2012, the U.S. Court of Appeals for the District of Columbia Circuit denied the petitioners' motion to stay the effectiveness of the COLs. Georgia Power has intervened in, and intends to vigorously contest, these petitions. Additional technical and procedural challenges to the construction and licensing of Plant Vogtle Units 3 and 4, at the federal and state level, are expected as construction proceeds.

Georgia Power is required to file semi-annual Vogtle Construction Monitoring (VCM) reports with the Georgia PSC by February 28 and August 31 each year. On February 19, 2013, the Georgia PSC voted to approve Georgia Power's seventh VCM report, including construction capital costs incurred through June 30, 2012 of approximately $2.0 billion. Georgia Power's eighth VCM report requests approval for an additional $0.2 billion of construction capital costs incurred through December 31, 2012. If the projected certified construction capital costs to be borne by Georgia Power increase by 5% or the projected in-service dates are significantly extended, Georgia Power is required to seek an amendment to the Plant Vogtle Units 3 and 4 certificate from the Georgia PSC. Accordingly, the eighth VCM also requests an amendment to the certificate to increase the estimated in-service capital cost of Plant Vogtle Units 3 and 4 to $4.8 billion and to extend the estimated in-service dates to fourth quarter 2017 and fourth quarter 2018 for Plant Vogtle Units 3 and 4, respectively. Associated financing costs during the construction period are estimated to total approximately $2.0 billion.

In July 2012, the Owners and the Contractor began negotiations regarding the costs associated with design changes to the DCD and the delays in the timing of approval of the DCD and issuance of the COLs, including the assertion by the Contractor that the Owners are responsible for these costs under the terms of the Vogtle 3 and 4 Agreement. The Contractor has claimed that its estimated adjustment attributable to Georgia Power (based on Georgia Power's ownership interest) is approximately $425 million (in 2008 dollars) with respect to these issues. The Contractor also has asserted it is entitled to further schedule extensions. Georgia Power has not agreed with either the proposed cost or schedule adjustments or that the Owners have any responsibility for costs related to these issues. On November 1, 2012, Georgia Power and the other Owners filed suit against the Contractor in the U.S. District Court for the Southern District of Georgia seeking a declaratory judgment that the Owners are not responsible for these costs. Also on November 1, 2012, the Contractor filed suit against Georgia Power and the other Owners in the U.S. District Court for the District of Columbia alleging the Owners are responsible for these costs. While litigation has commenced and Georgia Power intends to vigorously defend its positions, Georgia Power expects negotiations with the Contractor to continue with respect to cost and schedule during which negotiations the parties may reach a mutually acceptable compromise of their positions.

In addition, there are processes in place that are designed to assure compliance with the requirements specified in the DCD and the COLs, including rigorous inspections by Southern Nuclear and the NRC that occur throughout construction. During the fourth quarter 2012, certain details of the rebar design for the Plant Vogtle Unit 3 nuclear island were evaluated for consistency with the DCD and a few non-safety-related deviations were identified. On January 15, 2013 and January 18, 2013, Southern Nuclear submitted two license amendment requests to conform the rebar design details to NRC requirements. On January 29, 2013, the NRC issued "no objection" letters in response to the related preliminary amendment requests, enabling completion of final work supporting the pouring of base mat concrete, which is expected to occur following approval of the license amendment requests in March 2013. Various design and other issues are expected to arise as construction proceeds, which may result in additional license amendments or require other resolution. If any license amendment requests are not resolved in a timely manner, there may be delays in the project schedule that could result in increased costs either to the Owners, the Contractor, or both.

As construction continues, additional delays in the fabrication and assembly of structural modules, the failure of such modules to meet applicable standards, or other issues may further impact project schedule and cost. Additional claims by the Contractor or Georgia Power (on behalf of the Owners) are also likely to arise throughout construction. These claims may be resolved through formal and informal dispute resolution procedures under the Vogtle 3 and 4 Agreement, but also may be resolved through litigation.

The ultimate outcome of these matters cannot be determined at this time.

Integrated Coal Gasification Combined Cycle

General

Mississippi Power is constructing a new electric generating facility located in Kemper County, Mississippi which will utilize an integrated coal gasification combined cycle technology with an output capacity of 582 MWs (Kemper IGCC). The Kemper IGCC will use as fuel locally mined lignite (an abundant, lower heating value coal) from a mine owned by Mississippi Power and situated adjacent to the Kemper IGCC. In connection with the Kemper IGCC, Mississippi Power also plans to construct and operate approximately 61 miles of CO_2 pipeline infrastructure. The Kemper IGCC is scheduled to be placed in-service in May 2014.

In 2010, the Mississippi PSC issued a certificate of public convenience and necessity (CPCN) authorizing the acquisition, construction, and operation of the Kemper IGCC (2010 MPSC Order). The Sierra Club filed an appeal of the Mississippi PSC's issuance of the CPCN and, on March 15, 2012, the Mississippi Supreme Court reversed the decision of the Chancery Court of Harrison County, Mississippi (Chancery Court) upholding the 2010 MPSC Order and remanded the matter to the Mississippi PSC. The Mississippi Supreme Court concluded that the 2010 MPSC Order did not cite in sufficient detail substantial evidence upon which the Mississippi Supreme Court could determine the basis for the findings of the Mississippi PSC granting the CPCN. On March 30, 2012, the Mississippi PSC issued a temporary authorization which allowed Mississippi Power to continue construction and, on April 24, 2012, issued a detailed order (2012 MPSC Order) confirming the CPCN for the Kemper IGCC. On April 26, 2012, the Sierra Club appealed the 2012 MPSC Order to the Chancery Court. On December 17, 2012, the Chancery Court affirmed the 2012 MPSC Order which confirmed the issuance of the CPCN for the Kemper IGCC. On January 8, 2013, the Sierra Club filed an appeal of the Chancery Court's ruling with the Mississippi Supreme Court.

The certificated cost estimate of the Kemper IGCC included in the 2012 MPSC Order was $2.4 billion, net of $245 million of grants awarded to the project by the DOE under the Clean Coal Power Initiative Round 2 (CCPI2) and excluding the cost of the lignite mine and equipment, the cost of the CO_2 pipeline facilities, and financing costs related to the Kemper IGCC. The 2012 MPSC Order approved a construction cost cap of up to $2.88 billion, with recovery of prudently-incurred costs subject to approval by the Mississippi PSC. Exemptions from the cost cap included in the 2012 MPSC Order included the cost of the lignite mine and equipment, the cost of the CO_2 pipeline facilities, financing costs, and certain general exceptions, including change of law, force majeure, and beneficial capital (which exists when Mississippi Power demonstrates that the purpose and effect of the construction cost increase is to produce efficiencies that will result in a neutral or favorable effect on the ratepayers, relative to the original proposal for the CPCN).

Mississippi Power's current cost estimate for the Kemper IGCC (net of the $245 million CCPI2 grant, and excluding the cost of the lignite mine and equipment, the cost of the CO_2 pipeline facilities, financing costs, and certain general exceptions as contemplated in the 2012 MPSC Order and the settlement agreement between Mississippi Power and the Mississippi PSC entered into on January 24, 2013 (Settlement Agreement) that must be specifically approved by the Mississippi PSC) is approximately $2.88 billion. The Mississippi PSC and the Mississippi Public Utilities Staff (MPUS) have engaged their independent monitors to assess the current cost estimates and schedule projections for the Kemper IGCC. These consultants have issued reports with their own opinions as to the likelihood that costs for the Kemper IGCC will remain at or under the $2.88 billion cost cap and as to the expected in-service date. While Mississippi Power continues to believe its cost estimate and schedule projection remain appropriate based on the current status of the project, it is possible that Mississippi Power could experience further cost increases and/or schedule delays with respect to the Kemper IGCC. Certain factors have caused and may continue to cause the costs for the Kemper IGCC to increase and/or schedule delays to occur including, but not limited to, costs and productivity of labor, adverse weather conditions, shortages and inconsistent quality of equipment, materials, and labor, contractor or supplier delay or non-performance under construction or other agreements, and unforeseen engineering problems. To the extent it becomes probable that costs beyond any permitted exceptions to the cost cap will exceed $2.88 billion or it becomes probable that the Mississippi PSC will disallow a portion of the costs relating to the Kemper IGCC, including certain general exceptions as contemplated in the 2012 MPSC Order and the Settlement Agreement, charges to expense may occur and these charges could be material. See "Cost Recovery Plans" below for additional information relating to the Settlement Agreement that defines the process for resolving matters regarding cost recovery related to the Kemper IGCC.

As of December 31, 2012, Mississippi Power had spent a total of $2.51 billion on the Kemper IGCC, including the cost of the lignite mine and equipment, the cost of the CO_2 pipeline facilities, and other deferred costs. Of this total, $2.47 billion was included in CWIP (which is net of $245 million of CCPI2 grant funds), $35 million was recorded in other regulatory assets, $4 million was recorded in other deferred charges and assets, and $1 million was previously expensed. Consistent with the treatment of non-capital costs incurred during the pre-construction period, the Mississippi PSC granted Mississippi Power the authority to defer all non-capital Kemper IGCC-related costs to a regulatory asset during the construction period. This includes deferred costs associated with the generation resource planning, evaluation, and screening activities. The amortization period for the regulatory asset will be determined by the Mississippi PSC at a later date.

In addition, Mississippi Power is authorized to accrue carrying costs on the unamortized balance of such regulatory assets at a rate and in a manner to be determined by the Mississippi PSC in future cost recovery mechanism proceedings.

The 2012 MPSC Order established periodic prudence reviews during the annual CWIP review process. Of the total costs of $51 million incurred through March 2009, $46 million has been reviewed and deemed prudent by the Mississippi PSC. Due to the decision of the Mississippi PSC to deny the Certificated New Plant-A (CNP-A) rate filing and a 2012 rate request related to the Kemper IGCC described below, prudence reviews for the construction costs of the Kemper IGCC incurred after March 2009 have not been made. The Settlement Agreement provides for completion of all prudence reviews within six months of the date the Kemper IGCC is placed in service. See "Cost Recovery Plans" herein for additional information.

The ultimate outcome of these matters, including the determinations of prudency and the specific manner of recovery of prudently-incurred costs relating to the Kemper IGCC, is subject to further regulatory actions and cannot be determined at this time.

Cost Recovery Plans

The 2012 MPSC Order included provisions relating to both Mississippi Power's recovery of financing costs during the course of construction of the Kemper IGCC and Mississippi Power's recovery of costs following the date the Kemper IGCC is placed in service. In the 2012 MPSC Order, the Mississippi PSC approved financing cost recovery on CWIP balances not to exceed the $2.4 billion certificated cost estimate for the Kemper IGCC. The 2012 MPSC Order provided for the accrual of AFUDC in 2010 and 2011 and for the current recovery of financing costs on 100% of CWIP in 2012, 2013, and through May 1, 2014 (provided that the amount of financing cost recovery allowed is to be reduced by the amount of certain state and federal government construction cost incentives received by Mississippi Power and must be justified by a showing that such recovery will benefit customers over the life of the Kemper IGCC). With respect to recovery of costs following the in-service date of the Kemper IGCC, the 2012 MPSC Order provided for the establishment of operational cost and revenue parameters based upon assumptions in Mississippi Power's petition for the CPCN.

On June 1, 2012, the MPUS signed a joint stipulation with Mississippi Power to establish a proposed rate schedule detailing CNP-A and, on June 14, 2012, Mississippi Power submitted to the Mississippi PSC a filing to establish the new CNP-A rate schedule and a stipulated rate increase based upon the revenue request of between $55 million and $59 million to recover financing costs over the remainder of 2012. On June 22, 2012, the Mississippi PSC denied the proposed CNP-A rate schedule and the 2012 rate recovery filings submitted by Mississippi Power, pending a final ruling from the Mississippi Supreme Court regarding the Sierra Club's appeal of the Mississippi PSC's issuance of the CPCN for the Kemper IGCC.

On July 9, 2012, Mississippi Power appealed the Mississippi PSC's June 22, 2012 decision to the Mississippi Supreme Court and requested interim rates under bond of $55 million. On July 31, 2012, the Mississippi Supreme Court denied Mississippi Power's request for interim rates under bond until the Mississippi Supreme Court decides Mississippi Power's appeal of the Mississippi PSC's June 22, 2012 decision.

On January 24, 2013, Mississippi Power and the Mississippi PSC entered into the Settlement Agreement that (1) establishes the process for resolving matters regarding cost recovery related to the Kemper IGCC for the purpose of mitigating risks to Mississippi Power and its customers and expediting the regulatory process associated with future rate filings required under the Settlement Agreement and (2) resolves Mississippi Power's CNP-A rate appeal before the Mississippi Supreme Court.

On February 12, 2013, the Mississippi Supreme Court granted Mississippi Power and the Mississippi PSC's joint filing for dismissal of Mississippi Power's appeal of the Mississippi PSC's June 22, 2012 decision.

Under the terms of the Settlement Agreement, Mississippi Power and the Mississippi PSC will follow certain agreed-upon regulatory procedures and schedules for resolving the cost recovery matters related to the Kemper IGCC. These procedures and schedules include the following: (1) Mississippi Power's filing within 30 days of the Settlement Agreement of a new request to increase rates in 2013 in an amount not to exceed a $172 million annual revenue requirement, based upon projected investment as December 31, 2013, to be recorded to a regulatory liability to be used to mitigate rate impacts when the Kemper IGCC is placed

in service (which filing for $172 million was made on January 25, 2013); (2) the Mississippi PSC's decision on that matter within 50 days of Mississippi Power's request; (3) Mississippi Power's collaboration with the MPUS to file with the Mississippi PSC within three months of the Settlement Agreement a rate recovery plan for the Kemper IGCC for the first seven years of its operation, along with a proposed revenue requirement under such plan for 2014 through 2020 (which filing was made on February 26, 2013 as described below); (4) the Mississippi PSC's decision on the rate recovery plan within four months of that filing; (5) Mississippi Power's agreement to limit the portion of prudently-incurred Kemper IGCC costs to be included in rate base to the $2.4 billion certificated cost estimate, plus costs related to the lignite mine and CO_2 pipeline as well as any other costs permitted or determined to be excluded from the cost cap, provided that this limitation will not prevent Mississippi Power from securing alternate financing to recover any prudently-incurred Kemper IGCC costs, including financing costs and plant costs above the $2.4 billion certificated cost estimate, not otherwise recovered in any Mississippi PSC rate proceeding contemplated by the Settlement Agreement; and (6) the Mississippi PSC's completion of its prudence review of the Kemper IGCC costs incurred through 2012 within six months of the Settlement Agreement, an additional prudence review upon considering the seven-year rate plan for costs incurred through the most recent reporting period, and a final prudence review of the remaining project costs within six months of the Kemper IGCC's in-service date.

Legislation to authorize a multi-year rate plan and legislation to provide for alternate financing through securitization was passed in the Mississippi legislature and was signed by the Governor on February 26, 2013. Mississippi Power contemplates using securitization as provided in the legislation as its form of alternate financing for prudently-incurred Kemper IGCC costs, including financing costs and plant costs above the $2.4 billion certificated cost estimate, not otherwise recovered in any Mississippi PSC rate proceeding contemplated by the Settlement Agreement.

On February 26, 2013, Mississippi Power, in compliance with the Settlement Agreement, filed with the Mississippi PSC a rate recovery plan for the Kemper IGCC for 2014 through 2020, the first seven years of operation of the Kemper IGCC. The rate recovery plan proposes recovery of an annual revenue requirement of approximately $150 million of Kemper IGCC-related operational costs and rate base amounts, including plant costs equal to the $2.4 billion certificated cost estimate. Approval of Mississippi Power's request to increase rates in 2013 to mitigate the rate impacts of the Kemper IGCC filed on January 25, 2013 is integral to the rate recovery plan as the proposed filing contemplates amortization of the regulatory liability to be used to mitigate rate impacts from 2014 through 2020, based on a fixed amortization schedule that requires approval by the Mississippi PSC. Under the rate recovery plan filing, Mississippi Power proposes annual recovery to remain the same from 2014 through 2020 and, while it is the intent of Mississippi Power for the actual revenue requirement to equal the proposed revenue requirement for certain items, Mississippi Power proposes that the annual differences for those items through 2020 will be deferred, subject to accrual of carrying costs, and the cumulative balance will be reviewed at the end of the term of the Settlement Agreement by the Mississippi PSC for determination of the manner of the recovery. Mississippi Power proposes to secure recovery of prudently-incurred Kemper IGCC costs, including financing costs and plant costs above the $2.4 billion certificated cost estimate, not otherwise recovered in any Mississippi PSC rate proceeding contemplated by the Settlement Agreement to be provided for with alternate financing through securitization. The rate recovery necessary to recover the annual costs of securitization is proposed to be filed and begin after the Kemper IGCC is placed in service.

Under the terms of the Settlement Agreement, Mississippi Power has the right to terminate the Settlement Agreement if certain conditions, including the passage of multi-year rate plan legislation that is contemplated under the Settlement Agreement, are not met, if Mississippi Power is unable to secure alternate financing for any prudently-incurred Kemper IGCC costs not otherwise recovered in any Mississippi PSC rate proceeding contemplated by the Settlement Agreement, or if the Mississippi PSC fails to comply with the requirements of the Settlement Agreement.

The ultimate outcome of these matters, including the determinations of prudency and the specific manner of recovery of prudently-incurred costs relating to the Kemper IGCC, is subject to further regulatory actions and cannot be determined at this time.

Tax Incentives

The IRS has allocated $133 million (Phase I) and $279 million (Phase II) of Internal Revenue Code Section 48A tax credits to Mississippi Power in connection with the Kemper IGCC. Mississippi Power's utilization of Phase I and Phase II credits is dependent upon meeting the IRS certification requirements, including an in-service date no later than May 11, 2014 for the Phase I credits and April 19, 2016 for the Phase II credits. In order to remain eligible for the Phase II credits, Mississippi Power plans to capture and sequester (via enhanced oil recovery) at least 65% of the CO_2 produced by the Kemper IGCC during operations in accordance with the rules for Section 48A investment tax credits. Through December 31, 2012, Mississippi Power received or accrued tax benefits totaling $362 million for these tax credits, which will be amortized as a reduction to depreciation and amortization over the life of the Kemper IGCC. As a result of bonus tax depreciation on certain assets placed, or to be placed, in service in 2012 and 2013, and the subsequent reduction in federal taxable income, Mississippi Power estimates that it will not be

able to utilize $171 million of these tax credits until after 2013. IRS guidelines allow these unused tax credits to be carried forward for 20 years, expiring at the end of 2031, if not utilized before then. On October 15, 2012, Mississippi Power filed an application with the DOE for certification of the Kemper IGCC for additional tax credits under the Internal Revenue Code Section 48A (Phase III). A portion of the tax credits realized by Mississippi Power may be subject to recapture upon successful completion of South Mississippi Electric Power Association's (SMEPA) purchase of an undivided interest in the Kemper IGCC as described below. In addition, all or a portion of the tax credits will be subject to recapture if Mississippi Power fails to satisfy the in-service date requirements and carbon capture requirements described above.

On January 2, 2013, the American Taxpayer Relief Act of 2012 (ATRA) was signed into law. The ATRA retroactively extended several tax credits through 2013 and 50% bonus depreciation for property to be placed in service in 2013 (and for certain long-term production-period projects to be placed in service in 2014), which is expected to apply to the Kemper IGCC.

The ultimate outcome of these matters cannot be determined at this time.

Lignite Mine and CO_2 Pipeline Facilities

In conjunction with the Kemper IGCC, Mississippi Power will own the lignite mine and equipment and has acquired and will continue to acquire mineral reserves located around the Kemper IGCC site in Kemper County. The mine is scheduled to be placed in service in June 2013. The estimated capital cost of the mine is approximately $245 million, of which $163 million has been incurred through December 31, 2012.

In 2010, Mississippi Power executed a 40-year management fee contract with Liberty Fuels Company, LLC, a wholly-owned subsidiary of The North American Coal Corporation (Liberty Fuels), which will develop, construct, and manage the mining operations. Because Liberty Fuels conducts all of its activities on behalf of Mississippi Power, Liberty Fuels qualifies as a VIE for which Mississippi Power is the primary beneficiary. The contract with Liberty Fuels is effective through the end of the mine reclamation. As the mining permit holder, Liberty Fuels has a legal obligation to perform mine reclamation and Mississippi Power has a contractual obligation to fund all reclamation activities. Consistent with the requirements of consolidation accounting, Liberty Fuels is consolidated in the financial statements of Mississippi Power and accordingly the asset retirement cost and the asset retirement obligation have been recorded in Mississippi Power's financial statements. In addition to the obligation to fund the reclamation activities, Mississippi Power currently provides working capital support to Liberty Fuels through cash advances for capital purchases, payroll, and other operating expenses.

In addition, Mississippi Power will acquire, construct, and operate the CO_2 pipeline for the planned transport of captured CO_2 for use in enhanced oil recovery. Mississippi Power has entered into agreements with Denbury Onshore (Denbury), a subsidiary of Denbury Resources Inc., and Treetop Midstream Services, LLC (Treetop), an affiliate of Tellus Operating Group, LLC and a subsidiary of Tengrys, LLC, pursuant to which Denbury will purchase 70% of the CO_2 captured from the Kemper IGCC and Treetop will purchase 30% of the CO_2 captured from the Kemper IGCC. The estimated capital cost of the CO_2 pipeline facilities is approximately $132 million, of which $78 million has been incurred through December 31, 2012.

The ultimate outcome of these matters, including the determinations of prudency and the specific manner of recovery of prudently-incurred costs relating to the Kemper IGCC, is subject to further regulatory actions and cannot be determined at this time.

Proposed Sale of Undivided Interest to SMEPA

In 2010, Mississippi Power and SMEPA entered into an asset purchase agreement whereby SMEPA agreed to purchase a 17.5% undivided interest in the Kemper IGCC. On February 28, 2012, the Mississippi PSC approved the sale and transfer of 17.5% of the Kemper IGCC to SMEPA. On June 29, 2012, Mississippi Power and SMEPA signed an amendment to the asset purchase agreement whereby SMEPA extended its option to purchase until December 31, 2012 and reduced its purchase commitment percentage from a 17.5% to a 15% undivided interest in the Kemper IGCC, subject to approval by the Mississippi PSC. On December 31, 2012, Mississippi Power and SMEPA agreed to extend SMEPA's option to purchase through December 31, 2013.

The closing of this transaction is conditioned upon execution of a joint ownership and operating agreement, receipt of all construction permits, appropriate regulatory approvals, financing, and other conditions. On September 27, 2012, SMEPA received a conditional loan commitment from Rural Utilities Service to provide funding for SMEPA's undivided interest in the Kemper IGCC.

On March 6, 2012, Mississippi Power received a $150 million interest-bearing refundable deposit from SMEPA to be applied to the purchase. While the expectation is that the amount will be applied to the purchase price at closing, Mississippi Power would be required to refund the deposit upon the termination of the asset purchase agreement, within 60 days of a request by SMEPA for a full or partial refund, or within 15 days at SMEPA's discretion in the event that Mississippi Power is assigned a senior unsecured credit rating of BBB+ or lower by Standard and Poor's Ratings Services, a division of The McGraw Hill Companies,

Inc. (S&P) or Baa1 or lower by Moody's Investors Services, Inc. (Moody's) or ceases to be rated by either of these rating agencies. Given the interest-bearing nature of the deposit and SMEPA's ability to request a refund, the deposit has been presented as a current liability in Southern Company's balance sheet herein and as financing proceeds in Southern Company's statement of cash flows herein.

The ultimate outcome of these matters cannot be determined at this time.

Baseload Act

In the 2008 regular session of the Mississippi legislature, a bill was passed and signed by the Governor to enhance the Mississippi PSC's authority to facilitate development and construction of base load generation in the State of Mississippi (Baseload Act). The Baseload Act authorizes, but does not require, the Mississippi PSC to adopt a cost recovery mechanism that includes in retail base rates, prior to and during construction, all or a portion of the prudently-incurred pre-construction and construction costs incurred by a utility in constructing a base load electric generating plant. Prior to the passage of the Baseload Act, such costs would traditionally be recovered only after the plant was placed in service. The Baseload Act also provides for periodic prudence reviews by the Mississippi PSC and prohibits the cancellation of any such generating plant without the approval of the Mississippi PSC. In the event of cancellation of the construction of the plant without approval of the Mississippi PSC, the Baseload Act authorizes the Mississippi PSC to make a public interest determination as to whether and to what extent the utility will be afforded rate recovery for costs incurred in connection with such cancelled generating plant. There are legal challenges to the constitutionality of the Baseload Act currently pending before the Mississippi Supreme Court. The ultimate impact of this legislation will depend on the outcome of any legal challenges and cannot be determined at this time. See "Cost Recovery Plans" herein for additional information regarding certain legislation related to the Kemper IGCC.

4. JOINT OWNERSHIP AGREEMENTS

Alabama Power owns an undivided interest in Units 1 and 2 at Plant Miller and related facilities jointly with Power South Energy Cooperative, Inc. Georgia Power owns undivided interests in Plants Vogtle, Hatch, Scherer, and Wansley in varying amounts jointly with OPC, MEAG Power, the City of Dalton, Georgia, Florida Power & Light Company, and Jacksonville Electric Authority. In addition, Georgia Power has joint ownership agreements with OPC for the Rocky Mountain facilities and with Florida Power Corporation for a combustion turbine unit at Intercession City, Florida. Southern Power owns an undivided interest in Plant Stanton Unit A and related facilities jointly with the Orlando Utilities Commission, Kissimmee Utility Authority, and Florida Municipal Power Agency.

At December 31, 2012, Alabama Power's, Georgia Power's, and Southern Power's percentage ownership and investment (exclusive of nuclear fuel) in jointly-owned facilities in commercial operation with the above entities were as follows:

Facility (Type)	Percent Ownership	Plant in Service	Accumulated Depreciation	CWIP
		(in millions)		
Plant Vogtle (nuclear) Units 1 and 2	45.7%	$ 3,327	$ 1,996	$ 67
Plant Hatch (nuclear)	50.1	1,037	551	49
Plant Miller (coal) Units 1 and 2	91.8	1,401	551	8
Plant Scherer (coal) Units 1 and 2	8.4	161	78	77
Plant Wansley (coal)	53.5	801	240	8
Rocky Mountain (pumped storage)	25.4	181	116	—
Intercession City (combustion turbine)	33.3	12	4	1
Plant Stanton (combined cycle) Unit A	65.0	156	36	—

Georgia Power also owns 45.7% of Plant Vogtle Units 3 and 4 that are currently under construction. See Note 3 to the financial statements under "Retail Regulatory Matters – Georgia Power – Nuclear Construction" for additional information.

Alabama Power, Georgia Power, and Southern Power have contracted to operate and maintain the jointly owned facilities, except for Rocky Mountain and Intercession City, as agents for their respective co-owners. The companies' proportionate share of their plant operating expenses is included in the corresponding operating expenses in the statements of income and each company is responsible for providing its own financing.

5. INCOME TAXES

Southern Company files a consolidated federal income tax return and combined state income tax returns for the States of Alabama, Georgia, Mississippi, and Texas. Under a joint consolidated income tax allocation agreement, each subsidiary's current and deferred tax expense is computed on a stand-alone basis and no subsidiary is allocated more current expense than would be paid if it filed a separate income tax return. In accordance with IRS regulations, each company is jointly and severally liable for the federal tax liability.

Current and Deferred Income Taxes

Details of income tax provisions are as follows:

	2012	2011	2010
		(in millions)	
Federal —			
Current	**$ 177**	$ 57	$ 42
Deferred	**1,011**	1,035	898
	1,188	1,092	940
State —			
Current	**61**	8	(54)
Deferred	**85**	119	140
	146	127	86
Total	**$ 1,334**	$ 1,219	$ 1,026

Net cash payments/(refunds) for income taxes in 2012, 2011, and 2010 were $38 million, $(401) million, and $276 million, respectively.

The tax effects of temporary differences between the carrying amounts of assets and liabilities in the financial statements and their respective tax bases, which give rise to deferred tax assets and liabilities, are as follows:

	2012	2011
	(in millions)	
Deferred tax liabilities —		
Accelerated depreciation	$ 9,022	$ 7,882
Property basis differences	1,254	1,256
Leveraged lease basis differences	278	277
Employee benefit obligations	536	499
Under recovered fuel clause	16	82
Premium on reacquired debt	84	111
Regulatory assets associated with employee benefit obligations	988	1,198
Regulatory assets associated with asset retirement obligations	1,108	546
Other	333	276
Total	13,619	12,127
Deferred tax assets —		
Federal effect of state deferred taxes	394	393
Employee benefit obligations	1,678	1,594
Over recovered fuel clause	135	33
Other property basis differences	134	134
Deferred costs	39	55
Cost of removal	29	40
Tax credit carryforward	256	129
Unbilled revenue	101	110
Other comprehensive losses	84	81
Asset retirement obligations	720	546
Other	362	358
Total	3,932	3,473
Total deferred tax liabilities, net	9,687	8,654
Portion included in prepaid expenses (accrued income taxes), net	237	125
Deferred state tax assets	68	86
Valuation allowance	(54)	(56)
Accumulated deferred income taxes	$ 9,938	$ 8,809

At December 31, 2012, Southern Company had subsidiaries with State of Georgia net operating loss (NOL) carryforwards totaling $827 million, which could result in net state income tax benefits of $48 million, if utilized. However, the subsidiaries have established a valuation allowance for the potential $48 million tax benefit due to the remote likelihood that the tax benefit will be realized. These NOLs expire between 2013 and 2021. Beginning in 2002, the State of Georgia allowed Southern Company to file a combined return, which has prevented the creation of any additional NOL carryforwards.

At December 31, 2012, the tax-related regulatory assets to be recovered from customers were $1.4 billion. These assets are primarily attributable to tax benefits that flowed through to customers in prior years, to deferred taxes previously recognized at rates lower than the current enacted tax law, and to taxes applicable to capitalized interest.

At December 31, 2012, the tax-related regulatory liabilities to be credited to customers were $211 million. These liabilities are primarily attributable to deferred taxes previously recognized at rates higher than the current enacted tax law and to unamortized investment tax credits.

In accordance with regulatory requirements, deferred investment tax credits are amortized over the life of the related property with such amortization normally applied as a credit to reduce depreciation in the statements of income. Credits amortized in this manner amounted to $23 million in 2012, $19 million in 2011, and $23 million in 2010. At December 31, 2012, all investment tax credits available to reduce federal income taxes payable had not been utilized. The remaining investment tax credits will be carried forward and utilized in future years.

In 2010, the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010 (Tax Relief Act) was signed into law. Major tax incentives in the Tax Relief Act include 100% bonus depreciation for property placed in service after September 8, 2010 and through 2011 (and for certain long-term production-period projects placed in service in 2012) and 50% bonus depreciation for property placed in service in 2012 (and for certain long-term production-period projects to be placed in service in 2013). The application of the bonus depreciation provisions in the Tax Relief Act significantly increased deferred tax liabilities related to accelerated depreciation.

Effective Tax Rate

A reconciliation of the federal statutory income tax rate to the effective income tax rate is as follows:

	2012	2011	2010
Federal statutory rate	**35.0%**	35.0%	35.0%
State income tax, net of federal deduction	**2.5**	2.4	1.8
Employee stock plans dividend deduction	**(1.0)**	(1.1)	(1.2)
Non-deductible book depreciation	**0.9**	0.7	0.8
Difference in prior years' deferred and current tax rate	**(0.1)**	(0.1)	(0.1)
AFUDC-Equity	**(1.3)**	(1.5)	(2.2)
ITC basis difference	**(0.3)**	(0.2)	(0.4)
Other	**(0.1)**	(0.2)	(0.2)
Effective income tax rate	**35.6%**	35.0%	33.5%

Southern Company's effective tax rate is typically lower than the statutory rate due to its employee stock plans' dividend deduction and non-taxable AFUDC equity.

Unrecognized Tax Benefits

For 2012, the total amount of unrecognized tax benefits decreased by $50 million, resulting in a balance of $70 million as of December 31, 2012.

Changes during the year in unrecognized tax benefits were as follows:

	2012	2011	2010
		(in millions)	
Unrecognized tax benefits at beginning of year	**$ 120**	$ 296	$ 199
Tax positions from current periods	**13**	46	62
Tax positions increase from prior periods	**7**	1	62
Tax positions decrease from prior periods	**(56)**	(111)	(27)
Reductions due to settlements	**(10)**	(112)	—
Reductions due to expired statute of limitations	**(4)**	—	—
Balance at end of year	**$ 70**	$ 120	$ 296

The tax positions from current periods for 2012 relate primarily to the tax accounting method change for repairs-generation assets. See "Tax Method of Accounting for Repairs" herein for additional information. The decreases in tax positions from prior periods primarily relate to state income tax credits and the 2009 MC Asset Recovery, LLC refund claim. The American Jobs Creation Act of 2004 created a tax deduction for a portion of income attributable to U.S. production activities as defined in

Section 199 of the Internal Revenue Code (production activities deduction). The reductions due to settlements relate to a settlement with the IRS of the calculation methodology for the production activities deduction.

The impact on Southern Company's effective tax rate, if recognized, was as follows:

	2012	2011	2010
		(in millions)	
Tax positions impacting the effective tax rate	$ 5	$ 69	$ 217
Tax positions not impacting the effective tax rate	65	51	79
Balance of unrecognized tax benefits	$ 70	$ 120	$ 296

The tax positions impacting the effective tax rate for 2012 primarily relate to state income tax credits. The tax positions not impacting the effective tax rate for 2012 relate to the timing difference associated with the tax accounting method change for repairs-generation assets. See "Tax Method of Accounting for Repairs" herein for additional information. These amounts are presented on a gross basis without considering the related federal or state income tax impact.

Accrued interest for unrecognized tax benefits was as follows:

	2012	2011	2010
		(in millions)	
Interest accrued at beginning of year	$ 10	$ 29	$ 21
Interest reclassified due to settlements	(9)	(24)	—
Interest accrued during the year	—	5	8
Balance at end of year	$ 1	$ 10	$ 29

Southern Company classifies interest on tax uncertainties as interest expense. The interest reclassified due to settlements in 2012 is primarily associated with state income tax credits and a settlement with the IRS related to the calculation methodology for the production activities deduction.

Southern Company did not accrue any penalties on uncertain tax positions.

It is reasonably possible that the amount of the unrecognized tax benefits associated with a majority of Southern Company's unrecognized tax positions will significantly increase or decrease within 12 months. The resolution of the tax accounting method change for repairs-generation assets, as well as the conclusion or settlement of state audits, could impact the balances significantly. At this time, an estimate of the range of reasonably possible outcomes cannot be determined.

The IRS has audited and closed all of Southern Company's consolidated federal income tax returns prior to 2009 and has settled its audits of Southern Company's consolidated federal income tax returns for 2009 and 2010, in principle, pending final approval. Additionally, the IRS has audited and closed Southern Company's 2011 consolidated federal income tax return. For tax years 2010 through 2013, Southern Company is a participant in the Compliance Assurance Process of the IRS. The audits for Southern Company's state income tax returns have either been concluded, or the statute of limitations has expired, for years prior to 2007.

Tax Method of Accounting for Repairs

Southern Company submitted a tax accounting method change related to the deductibility of repair costs associated with its subsidiaries' generation, transmission, and distribution systems effective for the 2009 consolidated federal income tax return in 2010. In August 2011, the IRS issued a revenue procedure, which provides a safe harbor method of accounting that taxpayers may use to determine eligible repair costs for transmission and distribution property. The IRS continues to work with the utility industry in an effort to define eligible repair costs for generation assets in a consistent manner for all utilities. The IRS published regulations on the deduction and capitalization of expenditures related to tangible property that generally apply for tax years beginning on or after January 1, 2014. The utility industry anticipates more detailed guidance concerning these regulations. Due to the uncertainty regarding the ultimate resolution of the repair costs for generation assets, an unrecognized tax position has been recorded for the tax accounting method change for repairs-generation assets. The ultimate outcome of this matter cannot be determined at this time; however, it is not expected to materially impact net income.

6. FINANCING

Long-Term Debt Payable to an Affiliated Trust

Alabama Power has formed a wholly-owned trust subsidiary for the purpose of issuing preferred securities. The proceeds of the related equity investments and preferred security sales were loaned back to Alabama Power through the issuance of junior subordinated notes totaling $206 million as of December 31, 2012 and $206 million as of December 31, 2011, which constitute substantially all of the assets of this trust and are reflected in the balance sheets as long-term debt payable. Alabama Power considers that the mechanisms and obligations relating to the preferred securities issued for its benefit, taken together, constitute a full and unconditional guarantee by it of the trust's payment obligations with respect to these securities. At December 31, 2012 and 2011, trust preferred securities of $200 million and $200 million, respectively, were outstanding.

Securities Due Within One Year

A summary of scheduled maturities and redemptions of securities due within one year at December 31 was as follows:

	2012	2011
	(in millions)	
Senior notes	$ 2,085	$ 1,200
Other long-term debt	227	493
Capitalized leases	23	24
Total	$ 2,335	$ 1,717

Maturities through 2017 applicable to total long-term debt are as follows: $2.34 billion in 2013; $448 million in 2014; $2.44 billion in 2015; $1.37 billion in 2016; and $1.14 billion in 2017.

Bank Term Loans

Certain of the traditional operating companies have entered into various floating rate bank term loan agreements for loans bearing interest based on one-month London Interbank Offered Rate (LIBOR). At December 31, 2012, Mississippi Power had outstanding bank term loans totaling $175 million. At December 31, 2011, Mississippi Power had outstanding bank term loans totaling $240 million and Georgia Power had outstanding bank term loans totaling $450 million. Such amounts are reflected in the statements of capitalization as amounts due within one year.

During 2012, the traditional operating companies repaid approximately $565 million of floating rate bank notes bearing interest based on one-month LIBOR. In March 2012, Georgia Power paid at maturity a $250 million aggregate principal amount variable rate long-term bank note. In May 2012, Georgia Power repaid a $200 million aggregate principal amount variable rate short-term bank note due June 2012. In March 2012, Mississippi Power paid at maturity a $75 million aggregate principal amount variable rate long-term bank note. In September 2012, Mississippi Power paid at maturity a $40 million aggregate principal amount variable rate long-term bank note.

During 2012, Mississippi Power entered into a 366-day $100 million aggregate principal amount variable rate bank note bearing interest based on one-month LIBOR. The first advance in the amount of $50 million was made in November 2012. Subsequent to December 31, 2012, the second advance in the amount of $50 million was made. The proceeds of this loan were used for working capital and for other general corporate purposes, including Mississippi Power's continuous construction program.

These bank loans have covenants that limit debt levels to 65% of total capitalization, as defined in the agreements. For purposes of these definitions, debt excludes the long-term debt payable to affiliated trusts and other hybrid securities. At December 31, 2012, Mississippi Power was in compliance with its debt limits.

In addition, these bank loans contain cross default provisions that would be triggered if the borrower defaulted on other indebtedness above a specified threshold. The cross default provisions are restricted to the indebtedness, including any guarantee obligations, of the company that has such bank loans. Mississippi Power is currently in compliance with all such covenants.

Senior Notes

The traditional operating companies issued a total of $4.0 billion of senior notes in 2012. The proceeds of these issuances were used to repay approximately $2.8 billion of long-term indebtedness, to repay short-term indebtedness, and for other general corporate purposes, including the applicable subsidiary's continuous construction program.

At December 31, 2012 and 2011, Southern Company and its subsidiaries had a total of $17.4 billion and $15.9 billion, respectively, of senior notes outstanding. At December 31, 2012 and 2011, Southern Company had a total of $1.3 billion and $1.8 billion, respectively, of senior notes outstanding.

Since Southern Company is a holding company, the right of Southern Company and, hence, the right of creditors of Southern Company (including holders of Southern Company senior notes) to participate in any distribution of the assets of any subsidiary of Southern Company, whether upon liquidation, reorganization or otherwise, is subject to prior claims of creditors and preferred and preference stockholders of such subsidiary.

Pollution Control Revenue Bonds

Pollution control obligations represent loans to the traditional operating companies from public authorities of funds derived from sales by such authorities of revenue bonds issued to finance pollution control and solid waste disposal facilities. In some cases, the pollution control obligations represent obligations under installment sales agreements with respect to facilities constructed with the proceeds of pollution control bonds issued by public authorities. The traditional operating companies had $3.4 billion and $3.4 billion of outstanding pollution control revenue bonds at December 31, 2012 and 2011, respectively. The traditional operating companies are required to make payments sufficient for the authorities to meet principal and interest requirements of such bonds. Proceeds from certain issuances are restricted until qualifying expenditures are incurred.

Plant Daniel Revenue Bonds

In October 2011, in connection with Mississippi Power's election under its operating lease of Plant Daniel Units 3 and 4 to purchase the assets, Mississippi Power assumed the obligations of the lessor related to $270 million aggregate principal amount of Mississippi Business Finance Corporation Taxable Revenue Bonds, 7.13% Series 1999A due October 21, 2021, issued for the benefit of the lessor. See Note 1 under "Property, Plant, and Equipment" and "Assets Subject to Lien" herein for additional information.

Other Revenue Bonds

Other revenue bond obligations represent loans to Mississippi Power from a public authority of funds derived from the sale by such authority of revenue bonds issued to finance a portion of the costs of constructing the Kemper IGCC and related facilities.

In August 2012, the Mississippi Business Finance Corporation (MBFC) entered into an agreement to issue up to $42.5 million aggregate principal amount of MBFC Taxable Revenue Bonds, Series 2012A (Mississippi Power Company Project), up to $21.25 million aggregate principal amount of MBFC Taxable Revenue Bonds, Series 2012B (Mississippi Power Company Project), and up to $21.25 million aggregate principal amount of MBFC Taxable Revenue Bonds, Series 2012C (Mississippi Power Company Project) for the benefit of Mississippi Power. During 2012, the MBFC issued $8.97 million aggregate principal amount of MBFC Taxable Revenue Bonds (Mississippi Power Company Project), Series 2012A, $21.25 million aggregate principal amount of MBFC Taxable Revenue Bonds (Mississippi Power Company Project), Series 2012B, and $21.25 million aggregate principal amount of MBFC Taxable Revenue Bonds (Mississippi Power Company Project), Series 2012C for the benefit of Mississippi Power. The proceeds were used to reimburse Mississippi Power for the cost of the acquisition, construction, equipping, installation, and improvement of certain equipment and facilities for the lignite mining facility related to the Kemper IGCC. Any future issuances of the Series 2012A bonds will be used for this same purpose.

Mississippi Power had $50.0 million of such obligations outstanding related to tax-exempt revenue bonds at December 31, 2012 and 2011 and $51.5 million of such obligations related to taxable revenue bonds outstanding at December 31, 2012. Such amounts are reflected in the statements of capitalization as long-term senior notes and debt.

Other Obligations

In March 2012, Mississippi Power received a $150 million interest-bearing refundable deposit from SMEPA to be applied to the sale price for the proposed sale of an undivided interest in the Kemper IGCC. Until the acquisition is closed, the deposit bears interest at Mississippi Power's AFUDC rate adjusted for income taxes, which was 9.967% per annum at December 31, 2012, and is refundable to SMEPA upon termination of the asset purchase agreement related to such purchase, within 60 days of a request by SMEPA for a full or partial refund, or within 15 days at SMEPA's discretion in the event that Mississippi Power is assigned a

senior unsecured credit rating of BBB+ or lower by S&P or Baa1 or lower by Moody's or ceases to be rated by either of these rating agencies.

Assets Subject to Lien

Each of Southern Company's subsidiaries is organized as a legal entity, separate and apart from Southern Company and its other subsidiaries. Alabama Power and Gulf Power have granted one or more liens on certain of their respective property in connection with the issuance of certain series of pollution control revenue bonds with an outstanding principal amount of $194 million as of December 31, 2012. There are no agreements or other arrangements among the Southern Company system companies under which the assets of one company have been pledged or otherwise made available to satisfy obligations of Southern Company or any of its other subsidiaries.

In October 2011, Mississippi Power purchased Plant Daniel Units 3 and 4 for approximately $85 million in cash and the assumption of $270 million face value (with a fair value on the assumption date of $346 million) of debt obligations of the lessor related to Plant Daniel Units 3 and 4, which mature in 2021 and bear interest at a fixed stated interest rate of 7.13% per annum. These obligations are secured by Plant Daniel Units 3 and 4 and certain personal property. See Note 1 under "Property, Plant, and Equipment" for additional information.

Bank Credit Arrangements

At December 31, 2012, committed credit arrangements with banks were as follows:

	Expires[a]					Executable Term Loans		Due Within One Year	
Company	2013	2014	2016	Total	Unused	One Year	Two Years	Term Out	No Term Out
	(in millions)			*(in millions)*		*(in millions)*		*(in millions)*	
Southern Company	$ —	$ —	$ 1,000	$ 1,000	$ 1,000	$ —	$ —	$ —	$ —
Alabama Power	158	350	800	1,308	1,308	56	—	56	102
Georgia Power	—	250	1,500	1,750	1,740	—	—	—	—
Gulf Power	80	195	—	275	275	45	—	45	35
Mississippi Power	135	165	—	300	300	25	40	65	70
Southern Power	—	—	500	500	500	—	—	—	—
Other	50	—	—	50	50	25	—	25	25
Total	$ 423	$ 960	$ 3,800	$ 5,183	$ 5,173	$ 151	$ 40	$ 191	$ 232

(a) No credit arrangements expire in 2015.

Most of the credit arrangements require payment of commitment fees based on the unused portion of the commitments or the maintenance of compensating balances with the banks. Commitment fees average less than 1/4 of 1% for Southern Company, the traditional operating companies, and Southern Power. Compensating balances are not legally restricted from withdrawal.

Most of the credit arrangements with banks have covenants that limit debt levels to 65% of total capitalization, as defined in the agreements. For purposes of these definitions, debt excludes the long-term debt payable to affiliated trusts and, in certain arrangements, other hybrid securities. At December 31, 2012, Southern Company, the traditional operating companies, and Southern Power were each in compliance with their respective debt limit covenants.

In addition, certain credit arrangements contain cross default provisions to other indebtedness that would trigger an event of default if the applicable borrower defaulted on indebtedness or guarantee obligations over a specified threshold. The cross default provisions are restricted only to the indebtedness, including any guarantee obligations, of the company that has such credit arrangements. Southern Company, the traditional operating companies, and Southern Power are currently in compliance with all such covenants.

A portion of the $5.2 billion unused credit with banks is allocated to provide liquidity support to the traditional operating companies' variable rate pollution control revenue bonds and commercial paper programs. The amount of variable rate pollution control revenue bonds requiring liquidity support as of December 31, 2012 was approximately $1.8 billion.

Southern Company, the traditional operating companies, and Southern Power make short-term borrowings primarily through commercial paper programs that have the liquidity support of committed bank credit arrangements. Southern Company, the traditional operating companies, and Southern Power may also borrow through various other arrangements with banks. Commercial paper and short-term bank loans are included in notes payable in the balance sheets.

Details of short-term borrowings were as follows:

	Short-term Debt at the End of the Period[a]	
	Amount Outstanding	Weighted Average Interest Rate
	(in millions)	
December 31, 2012:		
Commercial paper	**$ 820**	**0.3%**
December 31, 2011:		
Commercial paper	$ 654	0.3 %
Short-term bank debt	200	1.2 %
Total	$ 854	0.5 %

(a) Excludes notes payable related to other energy service contracts of $5 million and $6 million at December 31, 2012 and 2011, respectively.

Redeemable Preferred Stock of Subsidiaries

Each of the traditional operating companies has issued preferred and/or preference stock. The preferred stock of Alabama Power and Mississippi Power contains a feature that allows the holders to elect a majority of such subsidiary's board of directors if dividends are not paid for four consecutive quarters. Because such a potential redemption-triggering event is not solely within the control of Alabama Power and Mississippi Power, this preferred stock is presented as "Redeemable Preferred Stock of Subsidiaries" in a manner consistent with temporary equity under applicable accounting standards. The preferred and preference stock at Georgia Power and the preference stock at Alabama Power and Gulf Power do not contain such a provision that would allow the holders to elect a majority of such subsidiary's board. As a result, under applicable accounting standards, the preferred and preference stock at Georgia Power and the preference stock at Alabama Power and Gulf Power are required to be shown as "noncontrolling interest," separately presented as a component of "Stockholders' Equity" on Southern Company's balance sheets, statements of capitalization, and statements of stockholders' equity.

There were no changes for the years ended December 31, 2012 and 2011 in redeemable preferred stock of subsidiaries for Southern Company.

7. COMMITMENTS

Fuel and Purchased Power Agreements

To supply a portion of the fuel requirements of the generating plants, the Southern Company system has entered into various long-term commitments for the procurement and delivery of fossil and nuclear fuel which are not recognized on the balance sheets. In 2012, 2011, and 2010, the traditional operating companies and Southern Power incurred fuel expense of $5.1 billion, $6.3 billion, and $6.7 billion, respectively, the majority of which was purchased under long-term commitments. Southern Company expects that a substantial amount of the Southern Company system's future fuel needs will continue to be purchased under long-term commitments. In addition, the Southern Company system has entered into various long-term commitments for the purchase of capacity and electricity, some of which are accounted for as operating leases or have been used by a third party to secure financing. Total capacity expense under PPAs accounted for as operating leases was $171 million, $199 million, and $180 million for 2012, 2011, and 2010, respectively.

Estimated total obligations under these commitments at December 31, 2012 were as follows:

	PPAs	
	Operating Leases	Other
	(in millions)	
2013	$ 164	$ 24
2014	200	19
2015	249	11
2016	258	11
2017	263	8
2018 and thereafter	2,369	69
Total	$ 3,503	$ 142

Operating Leases

The Southern Company system has operating lease agreements with various terms and expiration dates. Total rent expense was $155 million, $176 million, and $188 million for 2012, 2011, and 2010, respectively. Southern Company includes any step rents, escalations, and lease concessions in its computation of minimum lease payments, which are recognized on a straight-line basis over the minimum lease term.

As of December 31, 2012, estimated minimum lease payments under operating leases were as follows:

	Minimum Lease Payments		
	Barges & Railcars	Other	Total
		(in millions)	
2013	$ 71	$ 42	$ 113
2014	57	38	95
2015	24	29	53
2016	19	26	45
2017	11	21	32
2018 and thereafter	11	73	84
Total	$ 193	$ 229	$ 422

For the traditional operating companies, a majority of the barge and railcar lease expenses are recoverable through fuel cost recovery provisions. In addition to the above rental commitments, Alabama Power and Georgia Power have obligations upon expiration of certain leases with respect to the residual value of the leased property. These leases have terms expiring through 2018 with maximum obligations under these leases of $83 million. At the termination of the leases, the lessee may either exercise its purchase option, or the property can be sold to a third party. Alabama Power and Georgia Power expect that the fair market value of the leased property would substantially reduce or eliminate the payments under the residual value obligations.

Guarantees

As discussed above under "Operating Leases," Alabama Power and Georgia Power have entered into certain residual value guarantees.

8. COMMON STOCK

Stock Issued

During 2012, Southern Company issued 12.1 million shares of common stock for $397 million through employee and director stock plans. In 2011, Southern Company raised $723 million from the issuance of 21.9 million new common shares through the Southern Investment Plan and employee and director stock plans.

Stock Repurchased

In July 2012, Southern Company announced a program to repurchase shares to partially offset the incremental shares issued under its employee and director stock plans. Under this program, approximately 9 million shares have been repurchased through December 31, 2012 at a total cost of $430 million. In January 2013, Southern Company announced that it planned to continue this program through 2015. Pursuant to Board approval, Southern Company may repurchase shares through open market purchases or privately negotiated transactions, in accordance with applicable securities laws.

Shares Reserved

At December 31, 2012, a total of 130 million shares were reserved for issuance pursuant to the Southern Investment Plan, the Employee Savings Plan, the Outside Directors Stock Plan, and the Omnibus Incentive Compensation Plan (which includes stock options and performance shares units as discussed below). Of the total 130 million shares reserved, there were 39 million shares of common stock remaining available for awards under the Omnibus Incentive Compensation Plan as of December 31, 2012.

Stock Options

Southern Company provides non-qualified stock options through its Omnibus Incentive Compensation Plan to a large segment of Southern Company system employees ranging from line management to executives. As of December 31, 2012, there were 6,026 current and former employees participating in the stock option program. The prices of options were at the fair market value of the shares on the dates of grant. These options become exercisable pro rata over a maximum period of three years from the date of grant. Southern Company generally recognizes stock option expense on a straight-line basis over the vesting period which equates to the requisite service period; however, for employees who are eligible for retirement, the total cost is expensed at the grant date. Options outstanding will expire no later than 10 years after the date of grant, unless terminated earlier by the Southern Company Board of Directors in accordance with the Omnibus Incentive Compensation Plan. For certain stock option awards, a change in control will provide accelerated vesting.

The estimated fair values of stock options granted were derived using the Black-Scholes stock option pricing model. Expected volatility was based on historical volatility of Southern Company's stock over a period equal to the expected term. Southern Company used historical exercise data to estimate the expected term that represents the period of time that options granted to employees are expected to be outstanding. The risk-free rate was based on the U.S. Treasury yield curve in effect at the time of grant that covers the expected term of the stock options.

The following table shows the assumptions used in the pricing model and the weighted average grant-date fair value of stock options granted:

Year Ended December 31	2012	2011	2010
Expected volatility	**17.7%**	17.5%	17.4%
Expected term *(in years)*	**5.0**	5.0	5.0
Interest rate	**0.9%**	2.3%	2.4%
Dividend yield	**4.2%**	4.8%	5.6%
Weighted average grant-date fair value	**$3.39**	$3.23	$2.23

Southern Company's activity in the stock option program for 2012 is summarized below:

	Shares Subject to Option	Weighted Average Exercise Price
Outstanding at December 31, 2011	40,956,822	$ 33.88
Granted	7,153,669	44.50
Exercised	(12,120,419)	32.76
Cancelled	(73,769)	37.75
Outstanding at December 31, 2012	**35,916,303**	**$ 36.37**
Exercisable at December 31, 2012	**22,724,015**	**$ 34.09**

The number of stock options vested, and expected to vest in the future, as of December 31, 2012 was not significantly different from the number of stock options outstanding at December 31, 2012 as stated above. As of December 31, 2012, the weighted average remaining contractual term for the options outstanding and options exercisable was approximately six years and five years, respectively, and the aggregate intrinsic value for the options outstanding and options exercisable was $243 million and $199 million, respectively.

As of December 31, 2012, there was $8 million of total unrecognized compensation cost related to stock option awards not yet vested. That cost is expected to be recognized over a weighted-average period of approximately 11 months.

For the years ended December 31, 2012, 2011, and 2010, total compensation cost for stock option awards recognized in income was $23 million, $22 million, and $22 million, respectively, with the related tax benefit also recognized in income of $9 million, $8 million, and $9 million, respectively.

The total intrinsic value of options exercised during the years ended December 31, 2012, 2011, and 2010 was $162 million, $155 million, and $57 million, respectively. The actual tax benefit realized by the Company for the tax deductions from stock option exercises totaled $62 million, $60 million, and $22 million for the years ended December 31, 2012, 2011, and 2010, respectively.

Southern Company has a policy of issuing shares to satisfy share option exercises. Cash received from issuances related to option exercises under the share-based payment arrangements for the years ended December 31, 2012, 2011, and 2010 was $397 million, $528 million, and $198 million, respectively.

Performance Shares

Southern Company provides performance share award units through its Omnibus Incentive Compensation Plan to a large segment of Southern Company system employees ranging from line management to executives. The performance share units granted under the plan vest at the end of a three-year performance period which equates to the requisite service period. Employees that retire prior to the end of the three-year period receive a pro rata number of shares, issued at the end of the performance period, based on actual months of service prior to retirement. The value of the award units is based on Southern Company's total shareholder return (TSR) over the three-year performance period which measures Southern Company's relative performance against a group of industry peers. The performance shares are delivered in common stock following the end of the performance period based on Southern Company's actual TSR and may range from 0% to 200% of the original target performance share amount.

The fair value of performance share awards is determined as of the grant date using a Monte Carlo simulation model to estimate the TSR of Southern Company's stock among the industry peers over the performance period. Southern Company recognizes compensation expense on a straight-line basis over the three-year performance period without remeasurement. Compensation expense for awards where the service condition is met is recognized regardless of the actual number of shares issued. The expected volatility was based on the historical volatility of Southern Company's stock over a period equal to the performance period. The risk-free rate was based on the U.S. Treasury yield curve in effect at the time of grant that covers the performance period of the award units.

The following table shows the assumptions used in the pricing model and the weighted average grant-date fair value of performance share award units granted:

Year Ended December 31	**2012**	2011	2010
Expected volatility	**16.0%**	19.2%	20.7%
Expected term *(in years)*	**3.0**	3.0	3.0
Interest rate	**0.4%**	1.4%	1.4%
Annualized dividend rate	**$1.89**	$1.82	$1.75
Weighted average grant-date fair value	**$41.99**	$35.97	$30.13

Total unvested performance share units outstanding as of December 31, 2011 were 1,719,598. During 2012, 842,447 performance share units were granted, 842,710 performance share units were vested, and 86,179 performance share units were forfeited resulting in 1,633,156 unvested units outstanding at December 31, 2012. In January 2013, the vested performance share award units were converted into 1,137,817 shares outstanding at a share price of $43.05 for the three-year performance and vesting period ended December 31, 2012.

For the years ended December 31, 2012, 2011, and 2010, total compensation cost for performance share units recognized in income was $28 million, $18 million, and $9 million, respectively, with the related tax benefit also recognized in income of $11 million, $7 million, and $4 million, respectively. As of December 31, 2012, there was $33 million of total unrecognized compensation cost related to performance share award units that will be recognized over a weighted-average period of approximately 11 months.

Diluted Earnings Per Share

For Southern Company, the only difference in computing basic and diluted earnings per share is attributable to awards outstanding under the stock option and performance share plans. The effect of both stock options and performance share award units were determined using the treasury stock method. Shares used to compute diluted earnings per share were as follows:

	Average Common Stock Shares		
	2012	2011	2010
		(in millions)	
As reported shares	**871**	857	832
Effect of options and performance share award units	**8**	7	5
Diluted shares	**879**	864	837

Stock options and performance share award units that were not included in the diluted earnings per share calculation because they were anti-dilutive were immaterial as of December 31, 2012 and 2011. Assuming an average stock price of $47.89 and $42.67 (the highest exercise prices of the anti-dilutive options outstanding in 2012 and 2011, respectively), the effect of options and performance share award units would have been immaterial for the years ended December 31, 2012 and 2011.

Common Stock Dividend Restrictions

The income of Southern Company is derived primarily from equity in earnings of its subsidiaries. At December 31, 2012, consolidated retained earnings included $6.4 billion of undistributed retained earnings of the subsidiaries.

9. NUCLEAR INSURANCE

Under the Price-Anderson Amendments Act (Act), Alabama Power and Georgia Power maintain agreements of indemnity with the NRC that, together with private insurance, cover third-party liability arising from any nuclear incident occurring at the companies' nuclear power plants. The Act provides funds up to $12.6 billion for public liability claims that could arise from a single nuclear incident. Each nuclear plant is insured against this liability to a maximum of $375 million by American Nuclear Insurers (ANI), with the remaining coverage provided by a mandatory program of deferred premiums that could be assessed, after a nuclear incident, against all owners of commercial nuclear reactors. A company could be assessed up to $117.5 million per incident for each licensed reactor it operates but not more than an aggregate of $17.5 million per incident to be paid in a calendar year for each reactor. Such maximum assessment, excluding any applicable state premium taxes, for Alabama Power and Georgia Power, based on its ownership and buyback interests in all licensed reactors, is $235 million and $232 million, respectively, per incident, but not more than an aggregate of $35 million per company to be paid for each incident in any one year. Both the maximum assessment per reactor and the maximum yearly assessment are adjusted for inflation at least every five years. The next scheduled adjustment is due no later than October 29, 2013. See Note 4 to the financial statements herein for additional information on joint ownership agreements.

Alabama Power and Georgia Power are members of Nuclear Electric Insurance Limited (NEIL), a mutual insurer established to provide property damage insurance in an amount up to $500 million for members' operating nuclear generating facilities. Additionally, both companies have policies that currently provide decontamination, excess property insurance, and premature decommissioning coverage up to $2.25 billion for losses in excess of the $500 million primary coverage. This excess insurance is also provided by NEIL.

NEIL also covers the additional costs that would be incurred in obtaining replacement power during a prolonged accidental outage at a member's nuclear plant. Members can purchase this coverage, subject to a deductible waiting period of up to 26 weeks, with a maximum per occurrence per unit limit of $490 million. After the deductible period, weekly indemnity payments would be received until either the unit is operational or until the limit is exhausted in approximately three years. Alabama Power and Georgia Power each purchase the maximum limit allowed by NEIL, subject to ownership limitations. Each facility has elected a 12-week deductible waiting period.

A builders' risk property insurance policy has been purchased from NEIL for the construction of Plant Vogtle Units 3 and 4. This policy provides the Owners up to $2.75 billion for accidental property damage occurring during construction.

Under each of the NEIL policies, members are subject to assessments if losses each year exceed the accumulated funds available to the insurer under that policy. The current maximum annual assessments for Alabama Power and Georgia Power under the NEIL policies would be $42 million and $70 million, respectively.

Claims resulting from terrorist acts are covered under both the ANI and NEIL policies (subject to normal policy limits). The aggregate, however, that NEIL will pay for all claims resulting from terrorist acts in any 12-month period is $3.2 billion plus such additional amounts NEIL can recover through reinsurance, indemnity, or other sources.

For all on-site property damage insurance policies for commercial nuclear power plants, the NRC requires that the proceeds of such policies shall be dedicated first for the sole purpose of placing the reactor in a safe and stable condition after an accident. Any remaining proceeds are to be applied next toward the costs of decontamination and debris removal operations ordered by the NRC, and any further remaining proceeds are to be paid either to the company or to its debt trustees as may be appropriate under the policies and applicable trust indentures. In the event of a loss, the amount of insurance available might not be adequate to cover property damage and other expenses incurred. Uninsured losses and other expenses, to the extent not recovered from customers, would be borne by Alabama Power or Georgia Power, as applicable, and could have a material effect on Southern Company's financial condition and results of operations.

All retrospective assessments, whether generated for liability, property, or replacement power, may be subject to applicable state premium taxes.

10. FAIR VALUE MEASUREMENTS

Fair value measurements are based on inputs of observable and unobservable market data that a market participant would use in pricing the asset or liability. The use of observable inputs is maximized where available and the use of unobservable inputs is minimized for fair value measurement and reflects a three-tier fair value hierarchy that prioritizes inputs to valuation techniques used for fair value measurement.

- Level 1 consists of observable market data in an active market for identical assets or liabilities.
- Level 2 consists of observable market data, other than that included in Level 1, that is either directly or indirectly observable.
- Level 3 consists of unobservable market data. The input may reflect the assumptions of the Company of what a market participant would use in pricing an asset or liability. If there is little available market data, then the Company's own assumptions are the best available information.

In the case of multiple inputs being used in a fair value measurement, the lowest level input that is significant to the fair value measurement represents the level in the fair value hierarchy in which the fair value measurement is reported.

As of December 31, 2012, assets and liabilities measured at fair value on a recurring basis during the period, together with the level of the fair value hierarchy in which they fall, were as follows:

	Fair Value Measurements Using			
As of December 31, 2012:	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
		(in millions)		
Assets:				
Energy-related derivatives	$ —	$ 26	$ —	$ 26
Interest rate derivatives	—	10	—	10
Nuclear decommissioning trusts:[(a)]				
Domestic equity	453	65	—	518
Foreign equity	28	172	—	200
U.S. Treasury and government agency securities	—	134	—	134
Municipal bonds	—	55	—	55
Corporate bonds	—	234	—	234
Mortgage and asset backed securities	—	141	—	141
Other investments	—	20	—	20
Cash equivalents	384	—	—	384
Other investments	9	—	15	24
Total	$ 874	$ 857	$ 15	$ 1,746
Liabilities:				
Energy-related derivatives	$ —	$ 111	$ —	$ 111

(a) Includes the investment securities pledged to creditors and collateral received, and excludes receivables related to investment income, pending investment sales, and payables related to pending investment purchases and the lending pool. See Note I under "Nuclear Decommissioning" for additional information.

As of December 31, 2011, assets and liabilities measured at fair value on a recurring basis during the period, together with the level of the fair value hierarchy in which they fall, were as follows:

	Fair Value Measurements Using			
As of December 31, 2011:	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
		(in millions)		
Assets:				
Energy-related derivatives	$ —	$ 14	$ —	$ 14
Interest rate derivatives	—	13	—	13
Foreign currency derivatives	—	2	—	2
Nuclear decommissioning trusts:[(a)]				
Domestic equity	396	58	—	454
Foreign equity	124	48	—	172
U.S. Treasury and government agency securities	17	33	—	50
Municipal bonds	—	82	—	82
Corporate bonds	—	260	—	260
Mortgage and asset backed securities	—	151	—	151
Other investments	—	36	—	36
Cash equivalents and restricted cash	1,024	—	—	1,024
Other investments	3	50	14	67
Total	$ 1,564	$ 747	$ 14	$ 2,325
Liabilities:				
Energy-related derivatives	$ —	$ 245	$ —	$ 245
Interest rate derivatives	—	33	—	33
Foreign currency derivatives	—	3	—	3
Total	$ —	$ 281	$ —	$ 281

(a) Includes the investment securities pledged to creditors and collateral received, and excludes receivables related to investment income, pending investment sales, and payables related to pending investment purchases and the lending pool. See Note 1 under "Nuclear Decommissioning" for additional information.

Valuation Methodologies

The energy-related derivatives primarily consist of over-the-counter financial products for natural gas and physical power products including, from time to time, basis swaps. These are standard products used within the energy industry and are valued using the market approach. The inputs used are mainly from observable market sources, such as forward natural gas prices, power prices, implied volatility, and LIBOR interest rates. Interest rate and foreign currency derivatives are also standard over-the-counter financial products valued using the market approach. Inputs for interest rate derivatives include LIBOR interest rates, interest rate futures contracts, and occasionally implied volatility of interest rate options. Inputs for foreign currency derivatives are from observable market sources. See Note 11 for additional information on how these derivatives are used.

"Other investments" include investments in funds that are valued using the market approach and income approach. Securities that are traded in the open market are valued at the closing price on their principal exchange as of the measurement date. Discounts are applied in accordance with GAAP when certain trading restrictions exist. For investments that are not traded in the open market, the price paid will have been determined based on market factors including comparable multiples and the expectations regarding cash flows and business plan execution. As the investments mature or if market conditions change materially, further analysis of the fair market value of the investment is performed. This analysis is typically based on a metric, such as multiple of

earnings, revenues, earnings before interest and income taxes, or earnings adjusted for certain cash changes. These multiples are based on comparable multiples for publicly traded companies or other relevant prior transactions.

For fair value measurements of investments within the nuclear decommissioning trusts and rabbi trust funds, specifically the fixed income assets using significant other observable inputs and unobservable inputs, the primary valuation technique used is the market approach. External pricing vendors are designated for each of the asset classes in the nuclear decommissioning trusts and rabbi trust funds with each security discriminately assigned a primary pricing source, based on similar characteristics.

A market price secured from the primary source vendor is then evaluated by management in its valuation of the assets within the trusts. As a general approach, market pricing vendors gather market data (including indices and market research reports) and integrate relative credit information, observed market movements, and sector news into proprietary pricing models, pricing systems, and mathematical tools. Dealer quotes and other market information including live trading levels and pricing analysts' judgment are also obtained when available.

As of December 31, 2012 and 2011, the fair value measurements of investments calculated at net asset value per share (or its equivalent), as well as the nature and risks of those investments, were as follows:

	Fair Value	Unfunded Commitments	Redemption Frequency	Redemption Notice Period
As of December 31, 2012:	*(in millions)*			
Nuclear decommissioning trusts:				
Foreign equity funds	$ 117	None	Monthly	5 days
Corporate bonds – commingled funds	9	None	Daily	Not applicable
Equity – commingled funds	55	None	Daily/Monthly	Daily/7 days
Other – commingled funds	10	None	Daily	Not applicable
Trust-owned life insurance	96	None	Daily	15 days
Cash equivalents:				
Money market funds	384	None	Daily	Not applicable
As of December 31, 2011:				
Nuclear decommissioning trusts:				
Corporate bonds – commingled funds	$ 32	None	Daily	Not applicable
Equity – commingled funds	48	None	Daily/Monthly	Daily/7 days
Other – commingled funds	25	None	Daily	Not applicable
Trust-owned life insurance	87	None	Daily	15 days
Cash equivalents and restricted cash:				
Money market funds	1,024	None	Daily	Not applicable

The NRC requires licensees of commissioned nuclear power reactors to establish a plan for providing reasonable assurance of funds for future decommissioning. Alabama Power and Georgia Power have external trust funds to comply with the NRC's regulations. The foreign equity fund in the nuclear decommissioning trusts seeks to provide long-term capital appreciation. In pursuing this investment objective, the foreign equity fund primarily invests in a diversified portfolio of equity securities of foreign companies, including those in emerging markets. These equity securities may include, but are not limited to, common stocks, preferred stocks, real estate investment trusts, convertible securities and depository receipts, including American depositary receipts, European depositary receipts and global depository receipts, and rights and warrants to buy common stocks. Georgia Power may withdraw all or a portion of its investment on the last business day of each month subject to a minimum withdrawal of $1 million, provided that a minimum investment of $10 million remains. If notices of withdrawal exceed 20% of the aggregate value of the foreign equity fund, then the foreign equity fund's board may refuse to permit the withdrawal of all such investments and may scale down the amounts to be withdrawn pro rata and may further determine that any withdrawal that has been postponed will have priority on the subsequent withdrawal date.

The commingled funds in the nuclear decommissioning trusts are invested primarily in a diversified portfolio, including, but not limited to, commercial paper, notes, repurchase agreements, and other evidences of indebtedness with a maturity not exceeding 13 months from the date of purchase. The commingled funds will, however, generally maintain a dollar-weighted average portfolio maturity of 90 days or less. The assets may be longer term investment grade fixed income obligations with maturity shortening provisions. The primary objective for the commingled funds is a high level of current income consistent with stability of principal and liquidity. The commingled funds included within corporate bonds represent the investment of cash collateral received under the Funds' managers' securities lending program that can only be sold upon the return of the loaned securities. See Note 1 under "Nuclear Decommissioning" for additional information.

Alabama Power's nuclear decommissioning trust includes investments in TOLI. The taxable nuclear decommissioning trust invests in the TOLI in order to minimize the impact of taxes on the portfolio and can draw on the value of the TOLI through death proceeds, loans against the cash surrender value, and/or the cash surrender value, subject to legal restrictions. The amounts reported in the table above reflect the fair value of investments the insurer has made in relation to the TOLI agreements. The nuclear decommissioning trust does not own the underlying investments, but the fair value of the investments approximates the cash surrender value of the TOLI policies. The investments made by the insurer are in commingled funds. The commingled funds primarily include investments in domestic and international equity securities and predominantly high-quality fixed income securities. These fixed income securities may include U.S. Treasury and government agency fixed income securities, non-U.S. government and agency fixed income securities, domestic and foreign corporate fixed income securities, and, to some degree, mortgage and asset backed securities. The passively managed funds seek to replicate the performance of a related index. The actively managed funds seek to exceed the performance of a related index through security analysis and selection.

The money market funds are short-term investments of excess funds in various money market mutual funds, which are portfolios of short-term debt securities. The money market funds are regulated by the Securities and Exchange Commission and typically receive the highest rating from credit rating agencies. Regulatory and rating agency requirements for money market funds include minimum credit ratings and maximum maturities for individual securities and a maximum weighted average portfolio maturity. Redemptions are available on a same day basis up to the full amount of the Company's investment in the money market funds.

As of December 31, 2012 and 2011, other financial instruments for which the carrying amount did not equal fair value were as follows:

	Carrying Amount	Fair Value
	(in millions)	
Long-term debt:		
2012	**$ 21,530**	**$ 23,480**
2011	$ 20,272	$ 22,144

The fair values are determined using Level 2 measurements and are based on quoted market prices for the same or similar issues or on the current rates offered to Southern Company, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, and Southern Power.

11. DERIVATIVES

Southern Company, the traditional operating companies, and Southern Power are exposed to market risks, primarily commodity price risk, interest rate risk, and occasionally foreign currency risk. To manage the volatility attributable to these exposures, each company nets its exposures, where possible, to take advantage of natural offsets and enters into various derivative transactions for the remaining exposures pursuant to each company's policies in areas such as counterparty exposure and risk management practices. Each company's policy is that derivatives are to be used primarily for hedging purposes and mandates strict adherence to all applicable risk management policies. Derivative positions are monitored using techniques including, but not limited to, market valuation, value at risk, stress testing, and sensitivity analysis. Derivative instruments are recognized at fair value in the balance sheets as either assets or liabilities and are presented on a gross basis.

Energy-Related Derivatives

The traditional operating companies and Southern Power enter into energy-related derivatives to hedge exposures to electricity, gas, and other fuel price changes. However, due to cost-based rate regulations and other various cost recovery mechanisms, the traditional operating companies have limited exposure to market volatility in commodity fuel prices and prices of electricity. Each of the traditional operating companies manages fuel hedging programs, implemented per the guidelines of their respective state PSCs, through the use of financial derivative contracts, which is expected to continue to mitigate price volatility. Southern Power

has limited exposure to market volatility in commodity fuel prices and prices of electricity because its long-term sales contracts shift substantially all fuel cost responsibility to the purchaser. However, Southern Power has been and may continue to be exposed to market volatility in energy-related commodity prices as a result of sales of uncontracted generating capacity.

To mitigate residual risks relative to movements in electricity prices, the traditional operating companies and Southern Power may enter into physical fixed-price contracts for the purchase and sale of electricity through the wholesale electricity market. To mitigate residual risks relative to movements in gas prices, the traditional operating companies and Southern Power may enter into fixed-price contracts for natural gas purchases; however, a significant portion of contracts are priced at market.

Energy-related derivative contracts are accounted for in one of three methods:

- *Regulatory Hedges* – Energy-related derivative contracts which are designated as regulatory hedges relate primarily to the traditional operating companies' fuel hedging programs, where gains and losses are initially recorded as regulatory liabilities and assets, respectively, and then are included in fuel expense as the underlying fuel is used in operations and ultimately recovered through the respective fuel cost recovery clauses.
- *Cash Flow Hedges* – Gains and losses on energy-related derivatives designated as cash flow hedges which are mainly used to hedge anticipated purchases and sales and are initially deferred in OCI before being recognized in the statements of income in the same period as the hedged transactions are reflected in earnings.
- *Not Designated* – Gains and losses on energy-related derivative contracts that are not designated or fail to qualify as hedges are recognized in the statements of income as incurred.

Some energy-related derivative contracts require physical delivery as opposed to financial settlement, and this type of derivative is both common and prevalent within the electric industry. When an energy-related derivative contract is settled physically, any cumulative unrealized gain or loss is reversed and the contract price is recognized in the respective line item representing the actual price of the underlying goods being delivered.

At December 31, 2012, the net volume of energy-related derivative contracts for natural gas positions for the Southern Company system, together with the longest hedge date over which the respective entity is hedging its exposure to the variability in future cash flows for forecasted transactions and the longest date for derivatives not designated as hedges, were as follows:

	Net Purchased mmBtu*	Longest Hedge Date	Longest Non-Hedge Date
	(in millions)		
Southern Company	276	2017	2017

* million British thermal units

In addition to the volumes discussed in the table above, the traditional operating companies and Southern Power enter into physical natural gas supply contracts that provide the option to sell back excess gas due to operational constraints. The maximum expected volume of natural gas subject to such a feature is 6 million mmBtu.

For cash flow hedges, the amounts expected to be reclassified from OCI to revenue and fuel expense for the next 12-month period ending December 31, 2013 are immaterial for Southern Company.

Interest Rate Derivatives

Southern Company and certain subsidiaries may also enter into interest rate derivatives to hedge exposure to changes in interest rates. The derivatives employed as hedging instruments are structured to minimize ineffectiveness. Derivatives related to existing variable rate securities or forecasted transactions are accounted for as cash flow hedges where the effective portion of the derivatives' fair value gains or losses is recorded in OCI and is reclassified into earnings at the same time the hedged transactions affect earnings, with any ineffectiveness recorded directly to earnings. Derivatives related to existing fixed rate securities are accounted for as fair value hedges, where the derivatives' fair value gains or losses and hedged items' fair value gains or losses are both recorded directly to earnings, providing an offset, with any difference representing ineffectiveness.

At December 31, 2012, the following interest rate derivatives were outstanding:

	Notional Amount	Interest Rate Received	Interest Rate Paid*	Hedge Maturity Date	Fair Value Gain (Loss) December 31, 2012
	(in millions)				*(in millions)*
Fair value hedges of existing debt					
Southern Company	$ 350	4.15%	3-month LIBOR + 1.96% spread	May 2014	$ 10

* Weighted Average

For the year ended December 31, 2012, the Company had realized net losses of $52 million upon termination of certain interest rate derivatives at the same time the related debt was issued. The effective portion of these losses has been deferred in OCI and is being amortized to interest expense over the life of the original interest rate derivative, reflecting the period in which the forecasted hedged transaction affects earnings. The estimated pre-tax losses that will be reclassified from OCI to interest expense for the 12-month period ending December 31, 2013 are $14 million. The Company has deferred gains and losses that are expected to be amortized into earnings through 2037.

Foreign Currency Derivatives

Southern Company and certain subsidiaries may enter into foreign currency derivatives to hedge exposure to changes in foreign currency exchange rates arising from purchases of equipment denominated in a currency other than U.S. dollars. Derivatives related to a firm commitment in a foreign currency transaction are accounted for as a fair value hedge where the derivatives' fair value gains or losses and the hedged items' fair value gains or losses are both recorded directly to earnings. Derivatives related to a forecasted transaction are accounted for as a cash flow hedge where the effective portion of the derivatives' fair value gains or losses is recorded in OCI and is reclassified into earnings at the same time the hedged transactions affect earnings. Any ineffectiveness is recorded directly to earnings; however, Mississippi Power has regulatory approval allowing it to defer any ineffectiveness associated with firm commitments related to the Kemper IGCC to a regulatory asset. The derivatives employed as hedging instruments are structured to minimize ineffectiveness. At December 31, 2012, the fair value of the foreign currency derivative outstanding was immaterial.

Derivative Financial Statement Presentation and Amounts

At December 31, 2012 and 2011, the fair value of energy-related derivatives, interest rate derivatives, and foreign currency derivatives was reflected in the balance sheets as follows:

	Asset Derivatives			Liability Derivatives		
Derivative Category	Balance Sheet Location	2012	2011	Balance Sheet Location	2012	2011
		(in millions)			*(in millions)*	
Derivatives designated as hedging instruments for regulatory purposes						
Energy-related derivatives:						
	Other current assets	$ 10	$ 9	Liabilities from risk management activities	$ 74	$ 163
	Other deferred charges and assets	13	5	Other deferred credits and liabilities	35	72
Total derivatives designated as hedging instruments for regulatory purposes		$ 23	$ 14		$ 109	$ 235
Derivatives designated as hedging instruments in cash flow and fair value hedges						
Energy-related derivatives:						
	Other current assets	$ —	$ —	Liabilities from risk management activities	$ —	$ 1
Interest rate derivatives:						
	Other current assets	7	6	Liabilities from risk management activities	—	33
	Other deferred charges and assets	3	7	Other deferred credits and liabilities	—	—
Foreign currency derivatives:						
	Other current assets	—	—	Liabilities from risk management activities	—	1
Total derivatives designated as hedging instruments in cash flow and fair value hedges		$ 10	$ 13		$ —	$ 35
Derivatives not designated as hedging instruments						
Energy-related derivatives:						
	Other current assets	$ 1	$ —	Liabilities from risk management activities	$ 1	$ 9
	Other deferred charges and assets	2	—	Other deferred credits and liabilities	1	—
Foreign currency derivatives:						
	Other current assets	—	2	Liabilities from risk management activities	—	2
Total derivatives not designated as hedging instruments		$ 3	$ 2		$ 2	$ 11
Total		$ 36	$ 29		$ 111	$ 281

All derivative instruments are measured at fair value. See Note 10 for additional information.

At December 31, 2012 and 2011, the pre-tax effects of unrealized derivative gains (losses) arising from energy-related derivative instruments designated as regulatory hedging instruments and deferred on the balance sheets were as follows:

	Unrealized Losses			Unrealized Gains		
Derivative Category	**Balance Sheet Location**	**2012**	2011	**Balance Sheet Location**	**2012**	2011
		(in millions)			*(in millions)*	
Energy-related derivatives:	Other regulatory assets, current	**$ (74)**	$ (163)	Other regulatory liabilities, current	**$ 10**	$ 9
	Other regulatory assets, deferred	**(35)**	(72)	Other regulatory liabilities, deferred	**13**	5
Total energy-related derivative gains (losses)		**$ (109)**	$ (235)		**$ 23**	$ 14

For the years ended December 31, 2012, 2011, and 2010, the pre-tax effects of interest rate and foreign currency derivatives designated as fair value hedging instruments on the statements of income were as follows:

Derivatives in Fair Value Hedging Relationships

		Amount		
Derivative Category	**Statements of Income Location**	**2012**	2011	2010
			(in millions)	
Interest rate derivatives:	Interest expense	**$ (3)**	$ 3	$ 10
Foreign currency derivatives:	Other operations and maintenance	**1**	(4)	3
Total		**$ (2)**	$ (1)	$ 13

For the years ended December 31, 2012, 2011, and 2010, the pre-tax effects of interest rate derivatives designated as fair value hedging instruments on Southern Company's statements of income were offset by changes to the carrying value of long-term debt; there was no material impact on Southern Company's statements of income.

For the years ended December 31, 2012, 2011, and 2010, the pre-tax effects of foreign currency derivatives designated as fair value hedging instruments on Southern Company's statements of income were offset by changes in the fair value of the purchase commitment related to equipment purchases; therefore, there was no material impact on Southern Company's statements of income.

For the years ended December 31, 2012, 2011, and 2010, the pre-tax effects of derivatives designated as cash flow hedging instruments on the statements of income were as follows:

Derivatives in Cash Flow Hedging Relationships	Gain (Loss) Recognized in OCI on Derivative (Effective Portion)			Gain (Loss) Reclassified from Accumulated OCI into Income (Effective Portion)			
					Amount		
Derivative Category	2012	2011	2010	Statements of Income Location	2012	2011	2010
	(in millions)				*(in millions)*		
Energy-related derivatives	$ —	$ —	$ 1	Fuel	$ —	$ —	$ —
Interest rate derivatives	(19)	(28)	(3)	Interest expense, net of amounts capitalized	(18)	(14)	(25)
Foreign currency derivatives	—	—	1	Other operations and maintenance	—	—	1
				Other income (expense), net	—	(1)	—
Total	$ (19)	$ (28)	$ (1)		$ (18)	$ (15)	$ (24)

There was no material ineffectiveness recorded in earnings for any period presented.

For the Southern Company system's energy-related derivatives not designated as hedging instruments, a substantial portion of the pre-tax realized and unrealized gains and losses is associated with hedging fuel price risk of certain PPA customers and has no impact on net income or on fuel expense as presented in the Company's statements of income. As a result, the pre-tax effects of energy-related derivatives not designated as hedging instruments on the Company's statements of income were immaterial for any year presented.

Contingent Features

The Company does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. There are certain derivatives that could require collateral, but not accelerated payment, in the event of various credit rating changes of certain Southern Company subsidiaries. At December 31, 2012, the fair value of derivative liabilities with contingent features was $15 million.

At December 31, 2012, the Company had no collateral posted with its derivative counterparties. The maximum potential collateral requirements arising from the credit-risk-related contingent features, at a rating below BBB- and/or Baa3, were $15 million. Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. Included in these amounts are certain agreements that could require collateral in the event that one or more Southern Company system power pool participants has a credit rating change to below investment grade.

12. SEGMENT AND RELATED INFORMATION

Southern Company's reportable business segments are the sale of electricity in the Southeast by the four traditional operating companies and Southern Power. Revenues from sales by Southern Power to the traditional operating companies were $425 million, $359 million, and $371 million in 2012, 2011, and 2010, respectively. The "All Other" column includes parent Southern Company, which does not allocate operating expenses to business segments. Also, this category includes segments below the quantitative threshold for separate disclosure. These segments include investments in telecommunications and leveraged lease projects. All other intersegment revenues are not material. Financial data for business segments and products and services was as follows:

	Electric Utilities						
	Traditional Operating Companies	Southern Power	Eliminations	Total	All Other	Eliminations	Consolidated
				(in millions)			
2012							
Operating revenues	**$ 15,730**	**$ 1,186**	**$ (438)**	**$ 16,478**	**$ 141**	**$ (82)**	**$ 16,537**
Depreciation and amortization	**1,629**	**143**	**—**	**1,772**	**15**	**—**	**1,787**
Interest income	**21**	**1**	**—**	**22**	**19**	**(1)**	**40**
Interest expense	**757**	**63**	**—**	**820**	**39**	**—**	**859**
Income taxes	**1,307**	**93**	**—**	**1,400**	**(66)**	**—**	**1,334**
Segment net income (loss)*	**2,145**	**175**	**1**	**2,321**	**33**	**(4)**	**2,350**
Total assets	**58,600**	**3,780**	**(129)**	**62,251**	**1,116**	**(218)**	**63,149**
Gross property additions	**4,813**	**241**	**—**	**5,054**	**5**	**—**	**5,059**
2011							
Operating revenues	$ 16,763	$ 1,236	$ (412)	$ 17,587	$ 149	$ (79)	$ 17,657
Depreciation and amortization	1,576	124	—	1,700	16	1	1,717
Interest income	18	1	—	19	3	(1)	21
Interest expense	726	77	—	803	54	—	857
Income taxes	1,217	76	—	1,293	(74)	—	1,219
Segment net income (loss)*	2,052	162	—	2,214	(8)	(3)	2,203
Total assets	54,622	3,581	(127)	58,076	1,592	(401)	59,267
Gross property additions	4,589	255	—	4,844	9	—	4,853
2010							
Operating revenues	$ 16,712	$ 1,130	$ (468)	$ 17,374	$ 162	$ (80)	$ 17,456
Depreciation and amortization	1,376	119	—	1,495	18	—	1,513
Interest income	22	—	—	22	3	(1)	24
Interest expense	757	76	—	833	63	(1)	895
Income taxes	1,039	75	—	1,114	(89)	1	1,026
Segment net income (loss)*	1,860	131	—	1,991	(11)	(5)	1,975
Total assets	51,144	3,438	(128)	54,454	1,178	(600)	55,032
Gross property additions	4,029	405	—	4,434	9	—	4,443

* After dividends on preferred and preference stock of subsidiaries.

Products and Services

Electric Utilities' Revenues

Year	Retail	Wholesale	Other	Total
		(in millions)		
2012	**$ 14,187**	**$ 1,675**	**$ 616**	**$ 16,478**
2011	$ 15,071	$ 1,905	$ 611	$ 17,587
2010	$ 14,791	$ 1,994	$ 589	$ 17,374

13. QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

Summarized quarterly financial information for 2012 and 2011 is as follows:

Quarter Ended	Operating Revenues	Operating Income	Consolidated Net Income After Dividends on Preferred and Preference Stock of Subsidiaries	Per Common Share			
				Basic Earnings	Dividends	Trading Price Range	
						High	Low
		(in millions)					
March 2012	**$ 3,604**	**$ 766**	**$ 368**	**$ 0.42**	**$ 0.4725**	**$ 46.06**	**$ 43.71**
June 2012	**4,181**	**1,143**	**623**	**0.71**	**0.4900**	**48.45**	**44.22**
September 2012	**5,049**	**1,740**	**976**	**1.11**	**0.4900**	**48.59**	**44.64**
December 2012	**3,703**	**814**	**383**	**0.44**	**0.4900**	**47.09**	**41.75**
March 2011	$ 4,012	$ 854	$ 422	$ 0.50	$ 0.4550	$ 38.79	$ 36.51
June 2011	4,521	1,136	604	0.71	0.4725	40.87	37.43
September 2011	5,428	1,652	916	1.07	0.4725	43.09	35.73
December 2011	3,696	589	261	0.30	0.4725	46.69	41.00

The Southern Company system's business is influenced by seasonal weather conditions.

SELECTED CONSOLIDATED FINANCIAL AND OPERATING DATA
For the Periods Ended December 2008 through 2012
Southern Company and Subsidiary Companies 2012 Annual Report

	2012	2011	2010	2009	2008
Operating Revenues (in millions)	**$ 16,537**	$ 17,657	$ 17,456	$ 15,743	$ 17,127
Total Assets (in millions)	**$ 63,149**	$ 59,267	$ 55,032	$ 52,046	$ 48,347
Gross Property Additions (in millions)	**$ 5,059**	$ 4,853	$ 4,443	$ 4,913	$ 4,122
Return on Average Common Equity (percent)	**13.10**	13.04	12.71	11.67	13.57
Cash Dividends Paid Per Share of Common Stock	**$ 1.9425**	$ 1.8725	$ 1.8025	$ 1.7325	$ 1.6625
Consolidated Net Income After Dividends on Preferred and Preference Stock of Subsidiaries (in millions)	**$ 2,350**	$ 2,203	$ 1,975	$ 1,643	$ 1,742
Earnings Per Share —					
Basic	**$ 2.70**	$ 2.57	$ 2.37	$ 2.07	$ 2.26
Diluted	**2.67**	2.55	2.36	2.06	2.25
Capitalization (in millions):					
Common stock equity	**$ 18,297**	$ 17,578	$ 16,202	$ 14,878	$ 13,276
Preferred and preference stock of subsidiaries	**707**	707	707	707	707
Redeemable preferred stock of subsidiaries	**375**	375	375	375	375
Long-term debt	**19,274**	18,647	18,154	18,131	16,816
Total (excluding amounts due within one year)	**$ 38,653**	$ 37,307	$ 35,438	$ 34,091	$ 31,174
Capitalization Ratios (percent):					
Common stock equity	**47.3**	47.1	45.7	43.6	42.6
Preferred and preference stock of subsidiaries	**1.8**	1.9	2.0	2.1	2.3
Redeemable preferred stock of subsidiaries	**1.0**	1.0	1.1	1.1	1.2
Long-term debt	**49.9**	50.0	51.2	53.2	53.9
Total (excluding amounts due within one year)	**100.0**	100.0	100.0	100.0	100.0
Other Common Stock Data:					
Book value per share	**$ 21.09**	$ 20.32	$ 19.21	$ 18.15	$ 17.08
Market price per share:					
High	**$ 48.59**	$ 46.69	$ 38.62	$ 37.62	$ 40.60
Low	**41.75**	35.73	30.85	26.48	29.82
Close (year-end)	**42.81**	46.29	38.23	33.32	37.00
Market-to-book ratio (year-end) (percent)	**203.0**	227.8	199.0	183.6	216.6
Price-earnings ratio (year-end) (times)	**15.9**	18.0	16.1	16.1	16.4
Dividends paid (in millions)	**$ 1,693**	$ 1,601	$ 1,496	$ 1,369	$ 1,279
Dividend yield (year-end) (percent)	**4.5**	4.0	4.7	5.2	4.5
Dividend payout ratio (percent)	**72.0**	72.7	75.7	83.3	73.5
Shares outstanding (in thousands):					
Average	**871,388**	856,898	832,189	794,795	771,039
Year-end	**867,768**	865,125	843,340	819,647	777,192
Stockholders of record (year-end)	**149,628**	155,198	160,426 *	92,799	97,324
Traditional Operating Company Customers (year-end) (in thousands):					
Residential	**3,832**	3,809	3,813	3,798	3,785
Commercial	**580**	579	580	580	594
Industrial	**15**	15	15	15	15
Other	**9**	9	9	9	8
Total	**4,436**	4,412	4,417	4,402	4,402
Employees (year-end)	**26,439**	26,377	25,940	26,112	27,276

* In July 2010, Southern Company changed its transfer agent from Southern Company Services, Inc. to Mellon Investor Services LLC (n/k/a Computershare Shareowner Services, LLC). The change in the number of stockholders of record is primarily attributed to the calculation methodology used by Mellon Investor Services LLC.

SELECTED CONSOLIDATED FINANCIAL AND OPERATING DATA
For the Periods Ended December 2008 through 2012
Southern Company and Subsidiary Companies 2012 Annual Report

	2012	2011	2010	2009	2008
Operating Revenues (in millions):					
Residential	$ **5,891**	$ 6,268	$ 6,319	$ 5,481	$ 5,476
Commercial	**5,097**	5,384	5,252	4,901	5,018
Industrial	**3,071**	3,287	3,097	2,806	3,445
Other	**128**	132	123	119	116
Total retail	**14,187**	15,071	14,791	13,307	14,055
Wholesale	**1,675**	1,905	1,994	1,802	2,400
Total revenues from sales of electricity	**15,862**	16,976	16,785	15,109	16,455
Other revenues	**675**	681	671	634	672
Total	$ **16,537**	$ 17,657	$ 17,456	$ 15,743	$ 17,127
Kilowatt-Hour Sales (in millions):					
Residential	**50,454**	53,341	57,798	51,690	52,262
Commercial	**53,007**	53,855	55,492	53,526	54,427
Industrial	**51,674**	51,570	49,984	46,422	52,636
Other	**919**	936	943	953	934
Total retail	**156,054**	159,702	164,217	152,591	160,259
Wholesale sales	**27,563**	30,345	32,570	33,503	39,368
Total	**183,617**	190,047	196,787	186,094	199,627
Average Revenue Per Kilowatt-Hour (cents):					
Residential	**11.68**	11.75	10.93	10.60	10.48
Commercial	**9.62**	10.00	9.46	9.16	9.22
Industrial	**5.94**	6.37	6.20	6.04	6.54
Total retail	**9.09**	9.44	9.01	8.72	8.77
Wholesale	**6.08**	6.28	6.12	5.38	6.10
Total sales	**8.64**	8.93	8.53	8.12	8.24
Average Annual Kilowatt-Hour Use Per Residential Customer	**13,187**	13,997	15,176	13,607	13,844
Average Annual Revenue Per Residential Customer	$ **1,540**	$ 1,645	$ 1,659	$ 1,443	$ 1,451
Plant Nameplate Capacity Ratings (year-end) (megawatts)	**45,740**	43,555	42,961	42,932	42,607
Maximum Peak-Hour Demand (megawatts):					
Winter	**31,705**	34,617	35,593	33,519	32,604
Summer	**35,479**	36,956	36,321	34,471	37,166
System Reserve Margin (at peak) (percent)	**20.8**	19.2	23.3	26.4	15.3
Annual Load Factor (percent)	**59.5**	59.0	62.2	60.6	58.7
Plant Availability (percent)*:					
Fossil-steam	**89.4**	88.1	91.4	91.3	90.5
Nuclear	**94.2**	93.0	92.1	90.1	91.3
Source of Energy Supply (percent):					
Coal	**35.2**	48.7	55.0	54.7	64.0
Nuclear	**16.2**	15.0	14.1	14.9	14.0
Hydro	**1.7**	2.1	2.5	3.9	1.4
Oil and gas	**38.3**	28.0	23.7	22.5	15.4
Purchased power	**8.6**	6.2	4.7	4.0	5.2
Total	**100.0**	100.0	100.0	100.0	100.0

* Beginning in 2012, plant availability is calculated as a weighted equivalent availability.

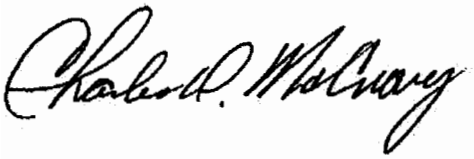
ALABAMA POWER COMPANY

FINANCIAL SECTION

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING
Alabama Power Company 2012 Annual Report

The management of Alabama Power Company (the Company) is responsible for establishing and maintaining an adequate system of internal control over financial reporting as required by the Sarbanes-Oxley Act of 2002 and as defined in Exchange Act Rule 13a-15(f). A control system can provide only reasonable, not absolute, assurance that the objectives of the control system are met.

Under management's supervision, an evaluation of the design and effectiveness of the Company's internal control over financial reporting was conducted based on the framework in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, management concluded that the Company's internal control over financial reporting was effective as of December 31, 2012.



Charles D. McCrary
President and Chief Executive Officer

Philip C. Raymond
Executive Vice President, Chief Financial Officer, and Treasurer

February 27, 2013

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of
Alabama Power Company

We have audited the accompanying balance sheets and statements of capitalization of Alabama Power Company (the Company) (a wholly owned subsidiary of The Southern Company) as of December 31, 2012 and 2011, and the related statements of income, comprehensive income, common stockholder's equity, and cash flows for each of the three years in the period ended December 31, 2012. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such financial statements (pages II-148 to II-196) present fairly, in all material respects, the financial position of Alabama Power Company as of December 31, 2012 and 2011, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2012, in conformity with accounting principles generally accepted in the United States of America.

Deloitte & Touche LLP

Birmingham, Alabama
February 27, 2013

OVERVIEW

Business Activities

Alabama Power Company (the Company) operates as a vertically integrated utility providing electricity to retail and wholesale customers within its traditional service territory located in the State of Alabama in addition to wholesale customers in the Southeast.

Many factors affect the opportunities, challenges, and risks of the Company's business of selling electricity. These factors include the ability to maintain a constructive regulatory environment, to maintain and grow energy sales given economic conditions, and to effectively manage and secure timely recovery of costs. These costs include those related to projected long-term demand growth, increasingly stringent environmental standards, fuel, capital expenditures, and restoration following major storms. Appropriately balancing required costs and capital expenditures with customer prices will continue to challenge the Company for the foreseeable future.

Key Performance Indicators

The Company continues to focus on several key performance indicators. These indicators include customer satisfaction, plant availability, system reliability, and net income after dividends on preferred and preference stock. The Company's financial success is directly tied to customer satisfaction. Key elements of ensuring customer satisfaction include outstanding service, high reliability, and competitive prices. Management uses customer satisfaction surveys and reliability indicators to evaluate the Company's results.

Peak season equivalent forced outage rate (Peak Season EFOR) is an indicator of fossil/hydro plant availability and efficient generation fleet operations during the months when generation needs are greatest. The rate is calculated by dividing the number of hours of forced outages by total generation hours. The fossil/hydro 2012 Peak Season EFOR was better than the target. Transmission and distribution system reliability performance is measured by the frequency and duration of outages. Performance targets for reliability are set internally based on historical performance. The performance for 2012 was better than the target for these reliability measures.

Net income after dividends on preferred and preference stock is the primary measure of the Company's financial performance. The Company's 2012 results compared to its targets for some of these key indicators are reflected in the following chart:

Key Performance Indicator	2012 Target Performance	2012 Actual Performance
Customer Satisfaction	**Top quartile in customer surveys**	**Top quartile**
Peak Season EFOR — fossil/hydro	**4.99% or less**	**0.75%**
Net Income After Dividends on Preferred and Preference Stock	**$701 million**	**$704 million**

See RESULTS OF OPERATIONS herein for additional information on the Company's financial performance. The performance achieved in 2012 reflects the continued emphasis that management places on these indicators, as well as the commitment shown by employees in achieving or exceeding management's expectations.

Earnings

The Company's 2012 net income after dividends on preferred and preference stock of $704 million decreased $4 million (0.6%) from the prior year. The decrease was due to decreases in weather-related revenues due to milder weather in 2012 compared to 2011 and an increase in other operations and maintenance expenses. The factors decreasing net income were partially offset by increases in revenues associated with the elimination of a tax-related adjustment under the Company's rate structure effective in the fourth quarter 2011 and an increase in retail sales growth.

The Company's 2011 net income after dividends on preferred and preference stock of $708 million increased $1 million (0.1%) from the prior year. The increase was due to a reduction in other operations and maintenance expenses, an increase in revenues under rate certificated new plant environmental (Rate CNP Environmental) associated with the completion of construction projects related to environmental mandates, and an increase in industrial kilowatt-hour (KWH) sales. The factors increasing net income were partially offset by reductions in wholesale revenues from sales to non-affiliates, decreases in weather-related revenues due to closer to normal weather in 2011 compared to 2010, and a reduction in allowance for funds used during construction (AFUDC) equity.

RESULTS OF OPERATIONS

A condensed income statement for the Company follows:

	Amount	Increase (Decrease) from Prior Year	
	2012	2012	2011
		(in millions)	
Operating revenues	$ 5,520	$ (182)	$ (274)
Fuel	1,503	(176)	(172)
Purchased power	255	(16)	(9)
Other operations and maintenance	1,287	25	(156)
Depreciation and amortization	639	2	31
Taxes other than income taxes	340	1	7
Total operating expenses	4,024	(164)	(299)
Operating income	1,496	(18)	25
Allowance for equity funds used during construction	19	(3)	(14)
Interest income	16	(2)	1
Interest expense, net of amounts capitalized	287	(12)	(4)
Other income (expense), net	(24)	6	—
Income taxes	477	(1)	15
Net income	743	(4)	1
Dividends on preferred and preference stock	39	—	—
Net income after dividends on preferred and preference stock	$ 704	$ (4)	$ 1

Operating Revenues

Operating revenues for 2012 were $5.5 billion, reflecting a $182 million decrease from 2011. Details of operating revenues were as follows:

	Amount	
	2012	2011
	(in millions)	
Retail — prior year	**$ 4,972**	$ 5,076
Estimated change in —		
Rates and pricing	**69**	88
Sales growth (decline)	**61**	42
Weather	**(115)**	(147)
Fuel and other cost recovery	**(54)**	(87)
Retail — current year	**4,933**	4,972
Wholesale revenues —		
Non-affiliates	**277**	287
Affiliates	**111**	244
Total wholesale revenues	**388**	531
Other operating revenues	**199**	199
Total operating revenues	**$ 5,520**	$ 5,702
Percent change	**(3.2)%**	(4.6)%

Retail revenues in 2012 were $4.9 billion. These revenues decreased $39 million (0.8%) in 2012 and decreased $104 million (2.0%) in 2011, each as compared to the prior year. The decrease in 2012 was due to milder weather, a reduction in revenues under Rate CNP Environmental, and a reduction in fuel revenues when compared to 2011. The decreases were partially offset by increased revenues associated with the elimination of a tax-related adjustment under the Company's rate structure and weather adjusted sales growth due to higher demand. The decrease in 2011 was due to closer to normal weather in 2011 compared to 2010 and a reduction in fuel revenues. The decreases were partially offset by increased revenues associated with Rate CNP Environmental for the completion of construction projects related to environmental mandates and the elimination of a tax-related adjustment under the Company's rate structure. See FUTURE EARNINGS POTENTIAL – "PSC Matters" herein and Note 3 to the financial statements under "Retail Regulatory Matters" for additional information. See "Energy Sales" for a discussion of changes in the volume of energy sold, including changes related to sales growth (decline) and weather.

Fuel rates billed to customers are designed to fully recover fluctuating fuel and purchased power costs over a period of time. Fuel revenues generally have no effect on net income because they represent the recording of revenues to offset fuel and purchased power expenses. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Energy Cost Recovery" herein and Note 3 to the financial statements under "Retail Regulatory Matters – Energy Cost Recovery" for additional information.

Wholesale revenues from sales to non-affiliated utilities were as follows:

	2012	2011	2010
		(in millions)	
Unit power sales —			
Capacity	**$ —**	$ —	$ 84
Energy	**—**	6	95
Total	**—**	6	179
Other power sales —			
Capacity and other	**143**	148	148
Energy	**134**	133	138
Total	**277**	281	286
Total non-affiliated	**$ 277**	$ 287	$ 465

Wholesale revenues from sales to non-affiliates will vary depending on the market prices of available wholesale energy compared to the cost of the Company's and the Southern Company system's generation, demand for energy within the Southern Company system's service territory, and availability of the Southern Company system's generation. Increases and decreases in energy revenues that are driven by fuel prices are accompanied by an increase or decrease in fuel costs and do not have a significant impact on net income.

In 2012, wholesale revenues from sales to non-affiliates decreased $10 million (3.5%) reflecting a $5 million decrease in revenue from energy sales and a $5 million decrease in capacity revenues. The price of energy decreased 5.2%, partially offset by a 1.8% increase in KWH sales. In 2011, wholesale revenues from sales to non-affiliates decreased $178 million (38.3%) reflecting a $94 million decrease in revenue from energy sales and an $84 million decrease in capacity revenues. These decreases were primarily due to the expiration of long-term unit power sales contracts in 2010. KWH sales decreased 46.9%, partially offset by a 15.3% increase in the price of energy. Short-term opportunity energy sales are also included in wholesale energy sales to non-affiliates. These opportunity sales are made at market-based rates that generally provide a margin above the Company's variable cost to produce the energy. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Retail Rate Adjustments" herein and Note 3 to the financial statements under "Retail Regulatory Matters – Rate RSE" for additional information.

Wholesale revenues from sales to affiliated companies will vary from year to year depending on demand and the availability and cost of generating resources at each company. These affiliated sales and purchases are made in accordance with the Intercompany Interchange Contract (IIC), as approved by the Federal Energy Regulatory Commission (FERC). These transactions do not have a significant impact on earnings since this energy is generally sold at marginal cost and energy purchases are generally offset by energy revenues through the Company's energy cost recovery clauses.

In 2012, wholesale revenues from sales to affiliates decreased $133 million (54.5%) primarily due to a $6 million decrease in capacity revenues and a $127 million decrease in energy sales. KWH sales decreased 45% and there was a 17.6% decrease in the price of energy. In 2011, wholesale revenues from sales to affiliates increased $8 million (3.4%). The change from prior year revenues was not material.

In 2012 and 2011, other operating revenues were $199 million. In 2011, the change from prior year revenues was not material.

Energy Sales

Changes in revenues are influenced heavily by the change in the volume of energy sold from year to year. KWH sales for 2012 and the percent change by year were as follows:

	Total KWHs	Total KWH Percent Change		Weather-Adjusted Percent Change	
	2012	**2012**	2011	**2012**	2011
	(in billions)				
Residential	**17.6**	**(5.6)%**	(8.7)%	**2.6%**	0.6%
Commercial	**14.0**	**(1.5)**	(3.7)	**0.6**	(0.6)
Industrial	**22.1**	**2.3**	5.1	**2.3**	5.1
Other	**0.2**	**—**	(0.9)	**—**	(0.9)
Total retail	**53.9**	**(1.4)**	(2.3)	**1.9%**	2.0%
Wholesale —					
Non-affiliates	**4.6**	**0.6**	(46.9)		
Affiliates	**3.9**	**(44.9)**	15.3		
Total wholesale	**8.5**	**(26.9)**	(21.3)		
Total energy sales	**62.4**	**(5.9)%**	(6.2)%		

Changes in retail energy sales are comprised of changes in electricity usage by customers, changes in weather, and changes in the number of customers. Retail energy sales in 2012 were 1.4% less than in 2011. Residential and commercial sales decreased 5.6% and 1.5%, respectively, due primarily to milder weather in 2012. Weather-adjusted residential sales increased 2.6%, primarily due to an increase in customer demand. Industrial sales increased 2.3% in 2012 as a result of increased customer demand, primarily in the pipelines, primary metals, chemicals, and automotive and plastics sectors, due to a recovering economy, partially offset by decreases in the textiles, and stone, clay and glass sectors.

Retail energy sales in 2011 were 2.3% less than in 2010. Residential and commercial sales decreased 8.7% and 3.7%, respectively, due primarily to closer to normal weather in 2011 compared to 2010. Industrial sales increased 5.1% in 2011 as a result of increased customer demand, primarily in the primary metals and chemicals sectors, due to a recovering economy.

See "Operating Revenues" above for a discussion of significant changes in wholesale revenues from sales to non-affiliates and wholesale revenues from sales to affiliated companies as related to changes in price and KWH sales.

Fuel and Purchased Power Expenses

Fuel costs constitute the single largest expense for the Company. The mix of fuel sources for generation of electricity is determined primarily by demand, the unit cost of fuel consumed, and the availability of generating units. Additionally, the Company purchases a portion of its electricity needs from the wholesale market.

Details of the Company's generation and purchased power were as follows:

	2012	2011	2010
Total generation *(billions of KWHs)*	**59.9**	64.8	69.2
Total purchased power *(billions of KWHs)*	**5.4**	4.7	5.0
Sources of generation *(percent)* —			
Coal	**53**	56	61
Nuclear	**25**	22	19
Gas	**18**	17	15
Hydro	**4**	5	5
Cost of fuel, generated *(cents per net KWH)* —			
Coal	**3.30**	3.16	3.02
Nuclear	**0.80**	0.66	0.60
Gas	**3.06**	3.92	4.47
Average cost of fuel, generated *(cents per net KWH)**	**2.61**	2.70	2.76
Average cost of purchased power *(cents per net KWH)***	**4.86**	6.04	6.42

* KWHs generated by hydro are excluded from the average cost of fuel, generated.

** Average cost of purchased power includes fuel purchased by the Company for tolling agreements where power is generated by the provider.

Fuel and purchased power expenses were $1.8 billion in 2012, a decrease of $192 million (9.8%) compared to 2011. The decrease was primarily due to a $143 million decrease related to lower KWHs generated due to milder weather in 2012 compared to 2011 and a $92 million decrease in the cost of natural gas and the average cost of purchased power, partially offset by increases in the cost of coal and nuclear fuel.

Fuel and purchased power expenses were $2.0 billion in 2011, a decrease of $181 million (8.5%) compared to 2010. The decrease was primarily due to a $108 million decrease related to lower KWHs generated as a result of closer to normal weather in 2011 compared to 2010, a reduction in unit power energy sales, and a $56 million decrease in the cost of natural gas and the average cost of purchased power, partially offset by increases in the cost of coal and nuclear fuel.

Fuel and purchased power energy transactions do not have a significant impact on earnings, since energy expenses are generally offset by energy revenues through the Company's Energy Cost Recovery Rate mechanism (Rate ECR). The Company, along with the Alabama Public Service Commission (PSC), continuously monitors the under/over recovered balance to determine whether adjustments to billing rates are required. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Energy Cost Recovery" herein and Note 3 to the financial statements under "Retail Regulatory Matters – Energy Cost Recovery" for additional information.

From an overall global market perspective, coal prices decreased from levels experienced in 2011 due to lower demand. In the U.S., this decrease was due primarily to relatively lower domestic natural gas prices that contributed to displacement of coal generation by natural gas-fueled generating units. Lower domestic natural gas prices in 2012 were driven by continued robust supplies, including production from shale gas, and only modest increases in overall U.S. consumption.

Uranium prices began to decrease during the second half of 2012 as extended reactor shutdowns in Europe and Asia caused global demand for uranium to drop below the level of previous years, while production increased. Changes in the cost of fuel for nuclear generation tend to lag behind changes in uranium market prices. Even though uranium prices decreased slightly during 2012, the cost of fuel for nuclear generation increased in 2012, reflecting the higher uranium prices from previous years when the uranium was purchased.

Fuel

Fuel expenses were $1.5 billion in 2012, a decrease of $176 million (10.5%) compared to 2011. This decrease was primarily due to a 21.9% decrease in the average cost of KWHs generated by natural gas, which excludes fuel associated with tolling agreements, and a 13.7% decrease in KWHs generated by coal, partially offset by 20.2% and 4.6% increases in the average cost of KWHs generated by nuclear fuel and coal, respectively. Fuel expenses were $1.7 billion in 2011, a decrease of $172 million (9.3%) compared to 2010. This decrease was primarily due to a 13.1% decrease in KWHs generated by coal and a 12.4% decrease in the average cost of KWHs generated by natural gas, which excludes fuel associated with tolling agreements, partially offset by a 10.7% increase in the average cost of KWHs generated by nuclear.

Purchased Power - Non-Affiliates

In 2012 and 2011, purchased power from non-affiliates was $73 million. In 2011, purchased power from non-affiliates increased $1 million. The increase over prior year costs was not material.

Energy purchases from non-affiliates will vary depending on the market prices of wholesale energy as compared to the cost of the Southern Company system's generation, demand for energy within the Southern Company system's service territory, and the availability of the Southern Company system's generation.

Purchased Power - Affiliates

Purchased power from affiliates was $182 million in 2012, a decrease of $16 million (8.1%) compared to 2011. This decrease was primarily due to a 9.6% decrease in the average cost per KWH, partially offset by a 1.7% increase in the amount of energy purchased. Purchased power from affiliates was $198 million in 2011, a decrease of $10 million (4.8%) compared to 2010. This decrease was primarily due to an 18.9% decrease in the average cost per KWH, partially offset by a 6.9% increase in the amount of energy purchased.

Energy purchases from affiliates will vary depending on demand for energy and the availability and cost of generating resources at each company within the Southern Company system. These purchases are made in accordance with the IIC or other contractual agreements, as approved by the FERC.

Other Operations and Maintenance Expenses

In 2012, other operations and maintenance expenses increased $25 million (2.0%) as compared to the prior year. Administrative and general expenses increased $45 million primarily related to pension and other benefit-related expenses and injuries and damages expenses. Nuclear production expenses increased $23 million primarily related to the amortization of nuclear outage expenses of $35 million due to a change in the nuclear maintenance outage accounting process associated with routine refueling activities, as approved by the Alabama PSC in 2010. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Nuclear Outage Accounting Order" herein for additional information. The increase in nuclear production expenses was partially offset by a decrease in operations costs related to labor expense. Other power generation expenses increased $6 million primarily related to scheduled outage costs and maintenance costs related to increases in labor and materials expenses. Transmission and distribution expenses decreased $32 million primarily related to a reduction in accruals to the natural disaster reserve (NDR). Steam production expenses decreased $22 million primarily related to a change in scheduled outage maintenance.

In 2011, other operations and maintenance expenses decreased $156 million (11.0%) as compared to the prior year. Transmission and distribution expenses decreased $79 million primarily related to vegetation management, reliability projects, and a reduction in accruals to the NDR. Nuclear production expenses decreased $33 million primarily related to the change in the nuclear maintenance outage accounting process in 2010 which resulted in no nuclear maintenance outage expenses being recognized in 2011, reducing nuclear production expense by approximately $50 million compared to the prior year. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Nuclear Outage Accounting Order" herein for additional information. The decrease in nuclear production expenses was partially offset by an increase in operations costs related to labor expense. Administrative and general expenses decreased $28 million primarily related to injuries and damages expenses, affiliated service companies' expenses, and property insurance.

See FUTURE EARNINGS POTENTIAL – "PSC Matters – Natural Disaster Reserve" herein for additional information.

Depreciation and Amortization

Depreciation and amortization increased $2 million (0.3%) in 2012 and $31 million (5.1%) in 2011, each as compared to the prior year. The increase in 2012 was not material. The increase in 2011 was primarily due to additions to property, plant, and equipment related to environmental mandates (which are offset by revenues associated with Rate CNP Environmental) and transmission and distribution projects. See Note 3 to financial statements under "Retail Regulatory Matters – Rate CNP" for additional information.

In 2011, the Company submitted a depreciation study to FERC and received authorization to use the recommended rates beginning in January 2012.

Taxes Other Than Income Taxes

Taxes other than income taxes increased $1 million (0.3%) in 2012 and $7 million (2.1%) in 2011, each as compared to the prior year. The increase in 2012 was not material. The increase in 2011 was primarily due to increases in state and municipal public utility license tax bases and an increase in local use tax.

Allowance for Funds Used During Construction Equity

AFUDC equity decreased $3 million (13.6%) in 2012 as compared to the prior year primarily due to a decrease in capital expenditures associated with general plant projects and nuclear-related fuel and facilities. These decreases were primarily offset by increases in transmission and hydro generating facilities. AFUDC equity decreased $14 million (38.9%) in 2011 as compared to the prior year primarily due to the completion of construction projects related to environmental mandates at Plants Barry, Gaston, and Miller. See Note 1 to financial statements under "Allowance for Funds Used During Construction" for additional information.

Interest Expense, Net of Amounts Capitalized

Interest expense, net of amounts capitalized decreased $12 million (4.0%) in 2012 and $4 million (1.3%) in 2011, each as compared to the prior year. The decrease in 2012 was primarily due to a decrease in interest on long term debt. The decrease in 2011 was not material.

Other Income (Expense), Net

Other income (expense), net increased $6 million (20.0%) in 2012 as compared to the prior year primarily due to an increase in non-operating income of $3 million, an increase in sales of property of $2 million, and a decrease in other deductions of $1 million. Other income (expense), net remained flat in 2011 as compared to the prior year.

Income Taxes

Income taxes decreased $1 million (0.2%) in 2012 and increased $15 million (3.2%) in 2011, each as compared to the prior year. The decrease in 2012 was not material. The increase in 2011 was primarily due to higher pre-tax income, an increase in the tax expense associated with a decrease in AFUDC equity, and prior year tax return actualization.

Effects of Inflation

The Company is subject to rate regulation that is generally based on the recovery of historical and projected costs. The effects of inflation can create an economic loss since the recovery of costs could be in dollars that have less purchasing power. Any adverse effect of inflation on the Company's results of operations has not been substantial in recent years. See Note 3 to financial statements under "Retail Regulatory Matters – Rate RSE" for additional information.

FUTURE EARNINGS POTENTIAL

General

The Company operates as a vertically integrated utility providing electricity to retail and wholesale customers within its traditional service area located in the State of Alabama in addition to wholesale customers in the Southeast. Prices for electricity provided by the Company to retail customers are set by the Alabama PSC under cost-based regulatory principles. Prices for wholesale electricity sales, interconnecting transmission lines, and the exchange of electric power are regulated by the FERC. Retail rates and earnings are reviewed and may be adjusted periodically within certain limitations. See ACCOUNTING POLICIES – "Application of Critical Accounting Policies and Estimates – Electric Utility Regulation" and "FERC Matters" herein and Note 3 to the financial statements under "Retail Regulatory Matters" for additional information about regulatory matters.

The results of operations for the past three years are not necessarily indicative of future earnings potential. The level of the Company's future earnings depends on numerous factors that affect the opportunities, challenges, and risks of the Company's primary business of selling electricity. These factors include the Company's ability to maintain a constructive regulatory environment that continues to allow for the timely recovery of prudently-incurred costs during a time of increasing costs. Future earnings in the near term will depend, in part, upon maintaining energy sales which is subject to a number of factors. These factors include weather, competition, new energy contracts with neighboring utilities, energy conservation practiced by customers, the price of electricity, the price elasticity of demand, and the rate of economic growth or decline in the Company's service territory. Changes in economic conditions impact sales for the Company, and the pace of the economic recovery remains uncertain. The timing and extent of the economic recovery will impact growth and may impact future earnings.

Environmental Matters

Compliance costs related to federal and state environmental statutes and regulations could affect earnings if such costs cannot continue to be fully recovered in rates on a timely basis. Environmental compliance spending over the next several years may differ materially from the amounts estimated. The timing, specific requirements, and estimated costs could change as environmental statutes and regulations are adopted or modified. Further, higher costs that are recovered through regulated rates could contribute to reduced demand for electricity, which could negatively affect results of operations, cash flows, and financial condition. See Note 3 to the financial statements under "Environmental Matters" for additional information.

New Source Review Actions

In 1999, the Environmental Protection Agency (EPA) brought a civil action in the U.S. District Court for the Northern District of Georgia against certain Southern Company subsidiaries, including the Company, alleging that these subsidiaries had violated the New Source Review (NSR) provisions of the Clean Air Act and related state laws at certain coal-fired generating facilities. The EPA alleged NSR violations at five coal-fired generating facilities operated by the Company and three coal-fired generating facilities operated by Georgia Power Company (Georgia Power). The civil action sought penalties and injunctive relief, including an order requiring installation of the best available control technology at the affected units. The case against Georgia Power was administratively closed in 2001 and has not been reopened. After the Company was dismissed from the original action, the EPA filed a separate action in 2001 against the Company in the U.S. District Court for the Northern District of Alabama.

In 2006, the U.S. District Court for the Northern District of Alabama entered a consent decree, resolving claims relating to the alleged NSR violations at Plant Miller. In 2010, the EPA dismissed five of its eight remaining claims against the Company, leaving only three claims, including one relating to a unit co-owned by Mississippi Power Company (Mississippi Power). In March 2011, the U.S. District Court for the Northern District of Alabama granted the Company summary judgment on all remaining claims and dismissed the case with prejudice. That judgment is on appeal to the U.S. Court of Appeals for the Eleventh Circuit. On February 23, 2012, the EPA filed a motion in the U.S. District Court for the Northern District of Alabama seeking vacatur of the judgment and recusal of the judge in the case involving the Company.

The Company believes it complied with applicable laws and regulations in effect at the time the work in question took place. The Clean Air Act authorizes maximum civil penalties of $25,000 to $37,500 per day, per violation, depending on the date of the alleged violation. An adverse outcome could require substantial capital expenditures that cannot be determined at this time and could possibly require payment of substantial penalties. Such expenditures could affect future results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates. The ultimate outcome of this matter cannot be determined at this time.

Climate Change Litigation

Kivalina Case

In 2008, the Native Village of Kivalina and the City of Kivalina filed a lawsuit in the U.S. District Court for the Northern District of California against several electric utilities (including Southern Company), several oil companies, and a coal company. The plaintiffs allege that the village is being destroyed by erosion allegedly caused by global warming that the plaintiffs attribute to emissions of greenhouse gases by the defendants. The plaintiffs assert claims for public and private nuisance and contend that some of the defendants (including Southern Company) acted in concert and are therefore jointly and severally liable for the plaintiffs' damages. The suit seeks damages for lost property values and for the cost of relocating the village, which is alleged to be $95 million to $400 million. In 2009, the U.S. District Court for the Northern District of California granted the defendants' motions to dismiss the case. On September 21, 2012, the U.S. Court of Appeals for the Ninth Circuit upheld the U.S. District Court for the Northern District of California's dismissal of the case. On November 27, 2012, the U.S. Court of Appeals for the Ninth Circuit denied the plaintiffs' request for review of the decision. On February 25, 2013, the plaintiffs filed a petition for writ of certiorari with the U.S. Supreme Court. Southern Company believes that these claims are without merit. The ultimate outcome of this matter cannot be determined at this time.

Hurricane Katrina Case

In 2005, immediately following Hurricane Katrina, a lawsuit was filed in the U.S. District Court for the Southern District of Mississippi by Ned Comer on behalf of Mississippi residents seeking recovery for property damage and personal injuries caused by Hurricane Katrina. In 2006, the plaintiffs amended the complaint to include Southern Company and many other electric utilities, oil companies, chemical companies, and coal producers. The plaintiffs allege that the defendants contributed to climate change, which contributed to the intensity of Hurricane Katrina. In 2007, the U.S. District Court for the Southern District of Mississippi dismissed the case. On appeal to the U.S. Court of Appeals for the Fifth Circuit, a three-judge panel reversed the U.S. District Court for the Southern District of Mississippi, holding that the case could proceed, but, on rehearing, the full U.S. Court of Appeals for the Fifth Circuit dismissed the plaintiffs' appeal, resulting in reinstatement of the decision of the U.S. District Court for the Southern District of Mississippi in favor of the defendants. In May 2011, the plaintiffs filed an amended version of their class action complaint, arguing that the earlier dismissal was on procedural grounds and under Mississippi law the plaintiffs have a right to re-file. The amended complaint was also filed against numerous chemical, coal, oil, and utility companies, including the Company. On March 20, 2012, the U.S. District Court for the Southern District of Mississippi dismissed the plaintiffs' amended complaint. On April 16, 2012, the plaintiffs appealed the case to the U.S. Court of Appeals for the Fifth Circuit. The Company believes that these claims are without merit. The ultimate outcome of this matter cannot be determined at this time.

Environmental Statutes and Regulations

General

The Company's operations are subject to extensive regulation by state and federal environmental agencies under a variety of statutes and regulations governing environmental media, including air, water, and land resources. Applicable statutes include the Clean Air Act; the Clean Water Act; the Comprehensive Environmental Response, Compensation, and Liability Act; the Resource Conservation and Recovery Act; the Toxic Substances Control Act; the Emergency Planning & Community Right-to-Know Act; the Endangered Species Act; and related federal and state regulations. Compliance with these environmental requirements involves significant capital and operating costs, a major portion of which is expected to be recovered through existing ratemaking provisions. Through 2012, the Company had invested approximately $3.0 billion in environmental capital retrofit projects to comply with these requirements, with annual totals of approximately $62 million, $34 million, and $130 million for 2012, 2011, and 2010, respectively. The Company expects that base level capital expenditures to comply with existing statutes and regulations, including capital expenditures and compliance costs associated with the EPA's final Mercury and Air Toxics Standards (MATS) rule, will be a total of approximately $1.0 billion from 2013 through 2015, with annual totals of approximately $195 million, $424 million, and $411 million for 2013, 2014, and 2015, respectively.

The Company continues to monitor the development of the EPA's proposed water and coal combustion byproducts rules and to evaluate compliance options. See FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" herein for the Company's anticipated incremental compliance costs related to the proposed water and coal combustion byproducts rules for 2013 through 2015. The ultimate capital expenditures and compliance costs with respect to these proposed rules, including additional expenditures required after 2015, will be dependent on the requirements of the final rules and regulations adopted by the EPA and the outcome of any legal challenges to these rules. See "Water Quality" and "Coal Combustion Byproducts" herein for additional information.

The Company's ultimate environmental compliance strategy, including potential unit retirement and replacement decisions, and future environmental capital expenditures will be affected by the final requirements of new or revised environmental regulations and regulations relating to global climate change that are promulgated, including the proposed environmental regulations described below; the outcome of any legal challenges to the environmental rules; the cost, availability, and existing inventory of emissions allowances; and the Company's fuel mix. Compliance costs may arise from existing unit retirements, installation of additional environmental controls, upgrades to the transmission system, and adding or changing fuel sources for certain existing units. The ultimate outcome of these matters cannot be determined at this time.

Southern Electric Generating Company (SEGCO), a subsidiary of the Company, is jointly owned with Georgia Power. As part of its environmental compliance strategy, SEGCO plans to add natural gas as the primary fuel source for its generating units in 2015. The capacity of SEGCO's units is sold equally to the Company and Georgia Power through a power purchase agreement (PPA). The impact of SEGCO's ultimate compliance strategy on such PPA costs cannot be determined at this time; however, if such costs cannot continue to be recovered through retail rates, they could have a material financial impact on the Company's financial statements. See Note 4 to the Company's financial statements for additional information.

Compliance with any new federal or state legislation or regulations relating to air quality, water, coal combustion byproducts, global climate change, or other environmental and health concerns could significantly affect the Company. Although new or revised environmental legislation or regulations could affect many areas of the Company's operations, the full impact of any such changes cannot be determined at this time. Additionally, many of the Company's commercial and industrial customers may also be affected by existing and future environmental requirements, which for some may have the potential to ultimately affect their demand for electricity.

Air Quality

Compliance with the Clean Air Act and resulting regulations has been and will continue to be a significant focus for the Company. Since 1990, the Company has spent approximately $2.7 billion in reducing and monitoring emissions pursuant to the Clean Air Act. Additional controls are currently planned or under consideration to further reduce air emissions, maintain compliance with existing regulations, and meet new requirements.

The EPA regulates ground level ozone concentrations through implementation of an eight-hour ozone air quality standard. In 2008, the EPA adopted a more stringent eight-hour ozone National Ambient Air Quality Standard, which it began to implement in September 2011. On May 21, 2012, the EPA published its final determination of nonattainment areas based on the 2008 eight-hour ozone air quality standards. No areas within the Company's service territory were determined to be in nonattainment of this standard.

The EPA regulates fine particulate matter concentrations on an annual and 24-hour average basis. All areas within the Company's service territory have achieved attainment with the 1997 and 2006 particulate matter National Ambient Air Quality Standards and, in January 2013, the EPA officially redesignated the Birmingham area as attainment under both the annual and 24-hour standards. On January 15, 2013, the EPA published a final rule that increases the stringency of the annual fine particulate matter standard. The new standard could result in the designation of new nonattainment areas within the Company's service territory.

Final revisions to the National Ambient Air Quality Standard for sulfur dioxide (SO_2), including the establishment of a new one-hour standard, became effective in 2010. The EPA plans to issue area designations under this new standard in June 2013, and areas within the Company's service territory could ultimately be designated as nonattainment. Implementation of the revised SO_2 standard could require additional reductions in SO_2 emissions and increased compliance and operational costs.

Revisions to the National Ambient Air Quality Standard for nitrogen dioxide (NO_2), which established a new one-hour standard, became effective in 2010. On February 29, 2012, the new NO_2 standard became effective. The EPA designated the entire country as "unclassifiable/attainment" under the new standard, with no nonattainment areas designated. However, the new NO_2 standard could result in significant additional compliance and operational costs for units that require new source permitting.

In 2008, the EPA approved a revision to Alabama's State Implementation Plan (SIP) requirements related to opacity, which granted some flexibility to affected sources while requiring compliance with Alabama's stringent opacity limits through use of continuous opacity monitoring system data. In April 2011, the EPA attempted to rescind its previous approval of the Alabama SIP revision. This decision impacts facilities operated by the Company, including units co-owned by Mississippi Power. The Company filed an appeal of that decision with the U.S. Court of Appeals for the Eleventh Circuit. The EPA's rescission has affected unit availability and increased maintenance and compliance costs. Unless the court resolves the Company's appeal in its favor, the EPA's rescission will continue to affect the Company's operations.

The Company's service territory is subject to the requirements of the Clean Air Interstate Rule (CAIR), which calls for phased reductions in SO_2 and nitrogen oxide (NO_x) emissions from power plants in 28 eastern states. In 2008, the U.S. Court of Appeals for the District of Columbia Circuit issued decisions invalidating CAIR, but left CAIR compliance requirements in place while the EPA developed a new rule. In August 2011, the EPA adopted the Cross State Air Pollution Rule (CSAPR) to replace CAIR effective January 1, 2012. However, in December 2011, the U. S. Court of Appeals for the District of Columbia Circuit stayed the rule and, on August 21, 2012, vacated CSAPR in its entirety and directed the EPA to continue to administer CAIR pending the EPA's development of a valid replacement. On January 24, 2013, the U.S. Court of Appeals for the District of Columbia Circuit denied requests by the EPA and other parties for rehearing.

The EPA finalized the Clean Air Visibility Rule (CAVR) in 2005, with a goal of restoring natural visibility conditions in certain areas (primarily national parks and wilderness areas) by 2064. The rule involves the application of best available retrofit technology (BART) to certain sources built between 1962 and 1977 and any additional emissions reductions necessary for each designated area to achieve reasonable progress toward the natural visibility conditions goal by 2018 and for each 10-year period thereafter. In 2005, the EPA determined that compliance with CAIR satisfies BART obligations under CAVR, but, on June 7, 2012, the EPA issued a final rule replacing CAIR with CSAPR as an alternative means of satisfying BART obligations. The vacatur of CSAPR creates additional uncertainty with respect to whether additional controls may be required for CAVR and BART compliance.

On February 16, 2012, the EPA published the final MATS rule, which imposes stringent emissions limits for acid gases, mercury, and particulate matter on coal- and oil-fired electric utility steam generating units. Compliance for existing sources is required by April 16, 2015, unless a one-year compliance extension is granted by the state or local air permitting agency.

Numerous petitions for administrative reconsideration of the MATS rule, including a petition by the Company, have been filed with the EPA. On November 30, 2012, the EPA proposed a reconsideration of certain new source and startup/shutdown issues. The EPA plans to complete its reconsideration rulemaking by March 2013. Challenges to the final rule have also been filed in the U.S. District Court for the District of Columbia by numerous states, environmental organizations, industry groups, and others.

On August 29, 2012, the EPA published proposed revisions to the New Source Performance Standard (NSPS) for Stationary Combustion Turbines (CTs). If finalized as proposed, the revisions would apply the NSPS to all new, reconstructed, and modified CTs (including CTs at combined cycle units), during all periods of operation, including startup and shutdown, and alter the criteria for determining when an existing CT has been reconstructed.

On February 12, 2013, the EPA proposed a rule that would require certain states to revise the provisions of their SIPs relating to the regulation of excess emissions at industrial facilities, including fossil-fuel fired generating facilities, during periods of startup, shut-down, or malfunction (SSM). The EPA proposes a determination that the SSM provisions in the SIPs for 36 states, including Alabama, do not meet the requirements of the Clean Air Act and must be revised within 18 months of the date on which the EPA publishes the final rule. If finalized as proposed, this new requirement could result in significant additional compliance and operational costs.

The Company has developed and continually updates a comprehensive environmental compliance strategy to assess compliance obligations associated with the existing and new environmental requirements discussed above. As part of this strategy, the Company has developed a compliance plan for the MATS rule which includes the construction of baghouses to provide an additional level of control on the emissions of mercury and particulates from certain generating units, the use of additives or other injection technology, and the use of existing or additional natural gas capability. Additionally, certain transmission system upgrades may be required. SEGCO, jointly owned by the Company and Georgia Power, plans to add natural gas capability.

The impacts of the eight-hour ozone, fine particulate matter, SO_2 and NO_2 standards, CAIR and any future replacement rule, CAVR, the MATS rule, the NSPS for CTs, and the SSM rule on the Company cannot be determined at this time and will depend on the specific provisions of recently finalized and future rules, the resolution of pending and future legal challenges, and the development and implementation of rules at the state level. These regulations could result in significant additional compliance costs that could affect future unit retirement and replacement decisions and results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates. Further, higher costs that are recovered through regulated rates could contribute to reduced demand for electricity, which could negatively impact results of operations, cash flows, and financial condition.

Water Quality

In April 2011, the EPA published a proposed rule that establishes standards for reducing effects on fish and other aquatic life caused by cooling water intake structures at existing power plants and manufacturing facilities. The rule also addresses cooling water intake structures for new units at existing facilities. Compliance with the proposed rule could require changes to existing cooling water intake structures at certain of the Company's generating facilities, and new generating units constructed at existing plants would be required to install closed cycle cooling towers. The EPA has entered into an amended settlement agreement to extend the deadline for issuing a final rule until June 27, 2013. If finalized as proposed, some of the Company's facilities may be subject to significant additional capital expenditures and compliance costs that could affect future unit retirement and replacement decisions. Also, results of operations, cash flows, and financial condition could be significantly impacted if such costs are not recovered through regulated rates. The ultimate outcome of this rulemaking will depend on the final rule and the outcome of any legal challenges and cannot be determined at this time.

The EPA has announced its determination that revision of the current effluent guidelines for steam electric power plants is warranted and has stated that it intends to propose such revisions by April 2013 and finalize the revisions by May 2014. New advanced wastewater treatment requirements are expected and may result in the installation of additional controls on certain of the Company's facilities, which could result in significant additional capital expenditures and compliance costs that could affect future unit retirement and replacement decisions. The impact of the revised guidelines will depend on the specific technology requirements of the final rule and, therefore, cannot be determined at this time. See FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" for additional information regarding estimated compliance costs for 2013 through 2015.

Coal Combustion Byproducts

The Company currently operates six electric generating plants with on-site coal combustion byproducts storage facilities. In addition to on-site storage, the Company also sells a portion of its coal combustion byproducts to third parties for beneficial reuse. Historically, individual states have regulated coal combustion byproducts and the State of Alabama has its own regulatory parameters. The Company has a routine and robust inspection program in place to ensure the integrity of its coal ash surface impoundments and compliance with applicable regulations.

The EPA continues to evaluate the regulatory program for coal combustion byproducts, including coal ash and gypsum, under federal solid and hazardous waste laws. In 2010, the EPA published a proposed rule that requested comments on two potential regulatory options for the management and disposal of coal combustion byproducts: regulation as a solid waste or regulation as if the materials technically constituted a hazardous waste. Adoption of either option could require closure of, or significant change to, existing storage facilities and construction of lined landfills, as well as additional waste management and groundwater monitoring requirements. Under both options, the EPA proposes to exempt the beneficial reuse of coal combustion byproducts from regulation; however, a hazardous or other designation indicative of heightened risk could limit or eliminate beneficial reuse options. Environmental groups and other parties have filed lawsuits in the U.S. District Court for the District of Columbia seeking to require the EPA to complete its rulemaking process and issue final regulations pertaining to the regulation of coal combustion byproducts.

While the ultimate outcome of this matter cannot be determined at this time and will depend on the final form of any rules adopted and the outcome of any legal challenges, additional regulation of coal combustion byproducts could have a material impact on the generation, management, beneficial use, and disposal of such byproducts. Any material changes are likely to result in substantial additional compliance, operational, and capital costs that could affect future unit retirement and replacement decisions. Moreover, the Company could incur additional material asset retirement obligations with respect to closing existing storage facilities. The Company's results of operations, cash flows, and financial condition could be significantly impacted if such costs are not recovered through regulated rates. Further, higher costs that are recovered through regulated rates could contribute to reduced demand for electricity, which could negatively impact results of operations, cash flows, and financial condition. See FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" for additional information regarding estimated compliance costs for 2013 through 2015.

Global Climate Issues

The EPA currently regulates greenhouse gases under the Prevention of Significant Deterioration and Title V operating permit programs of the Clean Air Act. In addition, over the past several years, the U.S. Congress has considered many proposals to reduce greenhouse gas emissions, mandate renewable or clean energy, and impose energy efficiency standards. Such proposals are expected to continue to be considered by the U.S. Congress. International climate change negotiations under the United Nations Framework Convention on Climate Change are also continuing.

On April 13, 2012, the EPA published proposed regulations to establish standards of performance for greenhouse gas emissions from new fossil fuel steam electric generating units. The EPA has also announced plans to develop federal guidelines for states to establish greenhouse gas emissions performance standards for existing sources. The impact of this rulemaking will depend on the scope and specific requirements of the final rule and the outcome of any legal challenges and, therefore, cannot be determined at this time.

Although the outcome of federal, state, and international initiatives cannot be determined at this time, additional restrictions on the Company's greenhouse gas emissions or requirements relating to renewable energy or energy efficiency at the federal or state level could result in significant additional compliance costs, including capital expenditures. These costs could affect future unit retirement and replacement decisions and could result in the retirement of a significant number of coal-fired generating units. Also, additional compliance costs and costs related to unit retirements could affect results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates. Further, higher costs that are recovered through regulated rates could contribute to reduced demand for electricity, which could negatively impact results of operations, cash flows, and financial condition.

The EPA's greenhouse gas reporting rule requires annual reporting of carbon dioxide equivalent emissions in metric tons for a company's operational control of facilities. Based on ownership or financial control of facilities, the Company reported 2011 greenhouse gas emissions of approximately 42 million metric tons of carbon dioxide equivalent. The preliminary estimate of the Company's 2012 greenhouse gas emissions on the same basis is approximately 38 million metric tons of carbon dioxide equivalent. The level of greenhouse gas emissions from year to year will depend on the level of generation and mix of fuel sources, which is determined primarily by demand, the unit cost of fuel consumed, and the availability of generating units.

FERC Matters

In 2005, the Company filed two applications with the FERC for new 50-year licenses for the Company's seven hydroelectric developments on the Coosa River (Weiss, Henry, Logan Martin, Lay, Mitchell, Jordan, and Bouldin) and for the Lewis Smith and Bankhead developments on the Warrior River. The FERC licenses for all of these nine projects expired in 2007. Since the FERC did not act on the Company's new license applications prior to the expiration of the existing licenses, the FERC is required by law to issue annual licenses to the Company, under the terms and conditions of the existing license, until action is taken on the new license applications. The FERC issued annual licenses for the Coosa River developments and the Warrior River developments in 2007. These annual licenses are automatically renewed each year without further action by the FERC to allow the Company to continue operation of the projects under the terms of the previous license while the FERC completes review of the applications for new licenses. Though the Coosa application remains pending before FERC, in 2010, the FERC issued a new 30 year license to the Company for the Warrior River developments. In 2010, the Smith Lake Improvement and Stakeholders' Association filed a request for rehearing of the FERC order granting the new Warrior license. On November 15, 2012, the FERC denied the Smith Lake Improvement and Stakeholders' Association's request for rehearing. On December 17, 2012, the Smith Lake Improvement and Stakeholders' Association filed for rehearing of the November 15, 2012 order and on January 16, 2013, the FERC denied the request.

In 2006, the Company initiated the process of developing an application to relicense the Martin Dam Project located on the Tallapoosa River. The current Martin license will expire on June 8, 2013. In June 2011, the Company filed an application with the FERC to relicense the Martin Dam Project.

In 2010, the Company initiated the process of developing an application to relicense the Holt Hydroelectric Project located on the Warrior River. The current Holt license will expire on August 31, 2015, and the application for a new license is expected to be filed no later than August 31, 2013.

Upon or after the expiration of each license, the U.S. Government, by act of Congress, may take over the project or the FERC may relicense the project either to the original licensee or to a new licensee. The FERC may grant relicenses subject to certain requirements that could result in additional costs to the Company. The timing and final outcome of the Company's relicense applications cannot be determined at this time.

PSC Matters

Retail Rate Adjustments

In July 2011, the Alabama PSC issued an order to eliminate a tax-related adjustment under the Company's rate structure effective with October 2011 billings. The elimination of this adjustment resulted in additional revenues of approximately $31 million for 2011. In accordance with the order, the Company made additional accruals to the NDR in the fourth quarter 2011 of an amount equal to such additional 2011 revenues. The NDR was impacted as a result of operations and maintenance expenses incurred in connection with the April 2011 storms in Alabama. See "Natural Disaster Reserve" below for additional information. The elimination of this adjustment resulted in additional revenues of approximately $106 million for 2012.

Rate RSE

Rate stabilization and equalization plan (Rate RSE) adjustments are based on forward-looking information for the applicable upcoming calendar year. Rate adjustments for any two-year period, when averaged together, cannot exceed 4.0% and any annual adjustment is limited to 5.0%. Retail rates remain unchanged when the retail return on common equity (ROE) is projected to be between 13.0% and 14.5%. If the Company's actual retail ROE is above the allowed equity return range, customer refunds will be required; however, there is no provision for additional customer billings should the actual retail ROE fall below the allowed equity return range.

In 2011 and 2012, retail rates under Rate RSE remained unchanged from 2010. On November 30, 2012, the Company made its Rate RSE submission to the Alabama PSC of projected data for calendar year 2013; projected earnings were within the specified return range, and, therefore, retail rates under Rate RSE remained unchanged for 2013. Under the terms of Rate RSE, the maximum possible increase for 2014 is 5.00%. However, the Company is working with the Alabama PSC to develop a plan that will potentially preclude the need for a Rate RSE increase in 2014. The ultimate outcome of this matter cannot be determined at this time.

Rate CNP

The Company's retail rates, approved by the Alabama PSC, provide for adjustments to recognize the placing of new generating facilities into retail service under rate certificated new plant (Rate CNP). The Company may also recover retail costs associated with certificated PPAs under rate certificated new plant (Rate CNP PPA). Effective April 2011, Rate CNP PPA was reduced by approximately $5 million annually. On March 6, 2012, the Alabama PSC issued a consent order that the Company leave in effect the current Rate CNP PPA factor for billings for the period April 1, 2012 through March 31, 2013. It is anticipated that no adjustment will be made to Rate CNP PPA in 2013. As of December 31, 2012, the Company had an under recovered certificated PPA balance of $9 million, $7 million of which is included in deferred under recovered regulatory clause revenues and $2 million of which is included in under recovered regulatory clause revenues in the balance sheet.

On September 17, 2012, the Alabama PSC approved and certificated a PPA for the purchase of approximately 200 megawatts (MWs) of the approximately 400 MWs of energy from wind-powered generating facilities and all associated environmental attributes, including renewable energy credits. The terms of this PPA and a previously approved and certificated PPA permit the Company to use the energy and retire the associated environmental attributes in service of its customers or to sell environmental attributes, separately or bundled with energy, to third parties. Approximately 200 MWs of energy from wind-powered generating facilities was operational in December 2012.

Rate CNP Environmental also allows for the recovery of the Company's retail costs associated with environmental laws, regulations, or other such mandates. Rate CNP Environmental is based on forward-looking information and provides for the recovery of these costs pursuant to a factor that is calculated annually. Environmental costs to be recovered include operations and maintenance expenses, depreciation, and a return on certain invested capital. There was no adjustment to Rate CNP Environmental to recover environmental costs in 2011 or 2012. On November 26, 2012, the Company submitted calculations associated with its cost of complying with environmental mandates, as provided under Rate CNP Environmental. The filing reflected a projected unrecovered retail revenue requirement for environmental compliance of less than $1 million, which is to be recovered in the billing months of January 2013 through December 2013. On December 4, 2012, the Alabama PSC issued a consent order that the Company leave in effect for 2013 the factors associated with the Company's environmental compliance costs for the year 2012. Any unrecovered amounts associated with 2013 will be reflected in the 2014 filing. As of December 31, 2012, the Company had an under recovered environmental clause balance of $21 million which is included in under recovered regulatory clause revenues in the balance sheet.

Environmental Accounting Order

Proposed and final environmental regulations could result in significant additional compliance costs that could affect future unit retirement and replacement decisions. In September 2011, the Alabama PSC approved an order allowing for the establishment of a regulatory asset to record the unrecovered investment costs associated with any such decisions, including the unrecovered plant asset balance and the unrecovered costs associated with site removal and closure. These costs would be amortized over the affected unit's remaining useful life, as established prior to the decision regarding early retirement. See "Environmental Matters – Environmental Statutes and Regulations" herein for additional information regarding environmental regulations.

Compliance and Pension Cost Accounting Order

On November 6, 2012, the Alabama PSC approved an accounting order for certain compliance-related operation and maintenance expenditures for the years 2013 through 2017, as well as the incremental increase in operation expense related to pension cost for 2013. Under the accounting order, expenses from January 2013 through December 2017 related to compliance with standards addressing Critical Infrastructure Protection issued by the North American Electric Reliability Corporation and cyber security requirements issued by the Nuclear Regulatory Commission (NRC) will be deferred to a regulatory asset account and amortized over a three-year period beginning in January 2015. Expenses from January 2013 through December 2017 related to compliance with NRC guidance addressing the readiness at nuclear facilities within the U.S., as prompted by the earthquake and tsunami that struck Japan in March 2011, also will be deferred as a regulatory asset and recovered over the same amortization period. The compliance-related expenses to be afforded regulatory asset treatment over the five-year period are currently estimated to be approximately $43 million. See "Other Matters" herein for information regarding the NRC's guidance issued as a result of the earthquake and tsunami that struck Japan in 2011. In addition, the accounting order authorizes the Company to defer an incremental increase in its pension cost for 2013. That increased pension cost is estimated to be approximately $17 million. During 2013, the actual incremental increase will be deferred to a regulatory asset account and will be amortized over a three-year period beginning in January 2015. Pursuant to the accounting order, the Company has the ability to accelerate the amortization of the regulatory assets.

Energy Cost Recovery

The Company has established energy cost recovery rates under Rate ECR as approved by the Alabama PSC. Rates are based on an estimate of future energy costs and the current over or under recovered balance. Revenues recognized under Rate ECR and recorded on the financial statements are adjusted for the difference in actual recoverable fuel costs and amounts billed in current regulated rates. The difference in the recoverable fuel costs and amounts billed give rise to the over or under recovered amounts recorded as regulatory assets or liabilities. The Company, along with the Alabama PSC, continually monitors the over or under recovered cost balance to determine whether an adjustment to billing rates is required. Changes in the Rate ECR factor have no significant effect on the Company's net income, but will impact operating cash flows. Currently, the Alabama PSC may approve billing rates under Rate ECR of up to 5.910 cents per KWH. On December 4, 2012, the Alabama PSC issued a consent order that the Company leave in effect the energy cost recovery rates which began in April 2011 for 2013. Therefore, the Rate ECR factor as of January 1, 2013 remained at 2.681 cents per KWH. Effective with billings beginning in January 2014, the Rate ECR factor will be 5.910 cents per KWH, absent a further order from the Alabama PSC.

As of December 31, 2012 and 2011, the Company had under recovered fuel balances of approximately $4 million and $31 million, respectively, which are included in deferred under recovered regulatory clause revenues in the balance sheets. This classification is based on estimates, which include such factors as weather, generation availability, energy demand, and the price of energy. A change in any of these factors could have a material impact on the timing of any recovery of the under recovered fuel costs.

Natural Disaster Reserve

Based on an order from the Alabama PSC, the Company maintains a reserve for operations and maintenance expenses to cover the cost of damages from major storms to its transmission and distribution facilities. The order approves a separate monthly Rate Natural Disaster Reserve (Rate NDR) charge to customers consisting of two components. The first component is intended to establish and maintain a reserve balance for future storms and is an on-going part of customer billing. The second component of the Rate NDR charge is intended to allow recovery of any existing deferred storm-related operations and maintenance costs and any future reserve deficits over a 24-month period. The Alabama PSC order gives the Company authority to record a deficit balance in the NDR when costs of storm damage exceed any established reserve balance. Absent further Alabama PSC approval, the maximum total Rate NDR charge consisting of both components is $10 per month per non-residential customer account and $5 per month per residential customer account. The Company has the authority, based on an order from the Alabama PSC, to accrue certain additional amounts as circumstances warrant. The order allows for reliability-related expenditures to be charged against the additional accruals when the NDR balance exceeds $75 million. The Company may designate a portion of the NDR to reliability-related expenditures as a part of an annual budget process for the following year or during the current year for identified unbudgeted reliability-related expenditures that are incurred. Accruals that have not been designated can be used to offset storm charges. Additional accruals to the NDR will enhance the Company's ability to deal with the financial effects of future natural disasters, promote system reliability, and offset costs retail customers would otherwise bear.

As revenue from the Rate NDR charge is recognized, an equal amount of operations and maintenance expenses related to the NDR will also be recognized. As a result, the Rate NDR charge will not have an effect on net income but will impact operating cash flows.

During the first half of 2011, multiple storms caused varying degrees of damage to the Company's transmission and distribution facilities. The most significant storms occurred in April 2011, causing over 400,000 of the Company's 1.4 million customers to be without electrical service. The cost of repairing the damage to facilities and restoring electrical service to customers as a result of these storms was $42 million for operations and maintenance expenses and $161 million for capital-related expenditures.

In accordance with the order that was issued by the Alabama PSC in July 2011 to eliminate a tax-related adjustment under the Company's rate structure that resulted in additional revenues, the Company made additional accruals to the NDR in the fourth quarter 2011 of an amount equal to the additional 2011 revenues, which were approximately $31 million.

The accumulated balances in the NDR for the years ended December 31, 2012 and December 31, 2011 were approximately $103 million and $110 million, respectively. Any accruals to the NDR are included in the balance sheets under other regulatory liabilities, deferred and are reflected as other operations and maintenance expenses in the statements of income.

Nuclear Outage Accounting Order

In 2010, the Alabama PSC approved a change to the nuclear maintenance outage accounting process associated with routine refueling activities. Previously, the Company accrued nuclear outage operations and maintenance expenses for the two units at Plant Farley during the 18-month cycle for the outages. In accordance with the 2010 order, nuclear outage expenses are deferred when the charges actually occur and then amortized over the subsequent 18-month period.

The initial result of implementation of the accounting order was that no nuclear maintenance outage expenses were recognized from January 2011 through December 2011, which decreased nuclear outage operations and maintenance expenses in 2011 from 2010 by approximately $50 million. During the fall of 2011, approximately $38 million of actual nuclear outage expenses associated with one unit at Plant Farley was deferred to a regulatory asset account; beginning in January 2012, these deferred costs are being amortized to nuclear operations and maintenance expenses over an 18-month period. During the spring of 2012, approximately $31 million of actual nuclear outage expenses associated with the second unit at Plant Farley was deferred to a regulatory asset account; beginning in July 2012, these deferred costs are being amortized to nuclear operations and maintenance expenses over an 18-month period. The Company will continue the pattern of deferral of nuclear outage expenses as incurred and the recognition of expenses over a subsequent 18-month period pursuant to the existing order.

Income Tax Matters

Bonus Depreciation

In 2010, the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010 (Tax Relief Act) was signed into law. Major tax incentives in the Tax Relief Act include 100% bonus depreciation for property placed in service after September 8, 2010 and through 2011 (and for certain long-term production-period projects placed in service in 2012) and 50% bonus depreciation for property placed in service in 2012 (and for certain long-term production-period projects to be placed in service in 2013), which will have a positive impact on the future cash flows of the Company through 2013.

On January 2, 2013, the American Taxpayer Relief Act of 2012 (ATRA) was signed into law. The ATRA retroactively extended several tax credits through 2013 and extended 50% bonus depreciation for property to be placed in service in 2013 (and for certain long-term production-period projects to be placed in service in 2014). The extension of 50% bonus depreciation will have a positive impact on the future cash flows of the Company through 2014.

Consequently, the Company's positive cash flow benefit is estimated to be between $110 million and $120 million in 2013.

Other Matters

In accordance with accounting standards related to employers' accounting for pensions, the Company recorded pension costs of $6 million in 2012 and recorded non-cash pre-tax pension income of $21 million and $19 million in 2011 and 2010, respectively. Postretirement benefit costs for the Company were $10 million, $11 million, and $14 million in 2012, 2011, and 2010, respectively. Such amounts are dependent on several factors including trust earnings and changes to the plans. A portion of pension and postretirement benefit costs is capitalized based on construction-related labor charges. Pension and postretirement benefit costs are a component of the regulated rates and generally do not have a long-term effect on net income. For more information regarding pension and postretirement benefits, see Note 2 to the financial statements.

The Company is involved in various other matters being litigated and regulatory matters that could affect future earnings. In addition, the Company is subject to certain claims and legal actions arising in the ordinary course of business. The Company's business activities are subject to extensive governmental regulation related to public health and the environment, such as regulation of air emissions and water discharges. Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements such as air quality and water standards, has increased generally throughout the U.S. In particular, personal injury, property damage, and other claims for damages alleged to have been caused by carbon dioxide and other emissions, coal combustion byproducts, and alleged exposure to hazardous materials, and/or requests for injunctive relief in connection with such matters, have become more frequent.

The ultimate outcome of such pending or potential litigation against the Company cannot be predicted at this time; however, for current proceedings not specifically reported herein or in Note 3 to the financial statements, management does not anticipate that the ultimate liabilities, if any, arising from such current proceedings would have a material effect on the Company's financial statements. See Note 3 to the financial statements for a discussion of various other contingencies, regulatory matters, and other matters being litigated which may affect future earnings potential.

In March 2011, a major earthquake and tsunami struck Japan and caused substantial damage to the nuclear generating units at the Fukushima Daiichi generating plant. The events in Japan have created uncertainties that may affect future costs for operating nuclear plants. Specifically, the NRC is performing additional operational and safety reviews of nuclear facilities in the U.S., which could potentially impact future operations and capital requirements. On March 12, 2012, the NRC issued three orders and a request for information based on the July 2011 NRC task force report recommendations that included, among other items, additional mitigation strategies for beyond-design-basis events, enhanced spent fuel pool instrumentation capabilities, hardened vents for certain classes of containment structures, site specific evaluations for seismic and flooding hazards, and various plant evaluations to ensure adequate coping capabilities during station blackout and other conditions. On August 29, 2012, the NRC staff issued the final interim staff guidance document, which offers acceptable approaches to meeting the requirements of the NRC's orders before the December 31, 2016 compliance deadline. The interim staff guidance is not mandatory, but licensees would be required to obtain NRC approval for taking an approach other than as outlined in the interim staff guidance. The final form and the resulting impact of any changes to safety requirements for nuclear reactors will be dependent on further review and action by the NRC. See "PSC Matters – Compliance and Pension Cost Accounting Order" herein and Note 3 to the financial statements under "Retail Regulatory Matters – Compliance and Pension Cost Accounting Order" for additional information on the Company's PSC approved accounting order, which allows the deferral of certain compliance-related operations and maintenance expenditures related to compliance with the NRC guidance.

See RISK FACTORS of the Company in Item 1A of the Form 10-K for a discussion of certain risks associated with the operation of nuclear generating units, including potential impacts that could result from a major incident at a nuclear facility anywhere in the world. The ultimate outcome of these events cannot be determined at this time.

ACCOUNTING POLICIES

Application of Critical Accounting Policies and Estimates

The Company prepares its financial statements in accordance with generally accepted accounting principles (GAAP). Significant accounting policies are described in Note 1 to the financial statements. In the application of these policies, certain estimates are made that may have a material impact on the Company's results of operations and related disclosures. Different assumptions and measurements could produce estimates that are significantly different from those recorded in the financial statements. Senior management has reviewed and discussed the following critical accounting policies and estimates with the Audit Committee of Southern Company's Board of Directors.

Electric Utility Regulation

The Company is subject to retail regulation by the Alabama PSC and wholesale regulation by the FERC. As a result, the Company applies accounting standards which require the financial statements to reflect the effects of rate regulation. Through the ratemaking process, the regulators may require the inclusion of costs or revenues in periods different than when they would be recognized by a non-regulated company. This treatment may result in the deferral of expenses and the recording of related regulatory assets based on anticipated future recovery through rates or the deferral of gains or creation of liabilities and the recording of related regulatory liabilities. The application of the accounting standards has a further effect on the Company's financial statements as a result of the estimates of allowable costs used in the ratemaking process. These estimates may differ from those actually incurred by the Company; therefore, the accounting estimates inherent in specific costs such as depreciation, nuclear decommissioning, and pension and postretirement benefits have less of a direct impact on the Company's results of operations and financial condition than they would on a non-regulated company.

As reflected in Note 1 to the financial statements, significant regulatory assets and liabilities have been recorded. Management reviews the ultimate recoverability of these regulatory assets and any requirement to refund these regulatory liabilities based on applicable regulatory guidelines and GAAP. However, adverse legislative, judicial, or regulatory actions could materially impact the amounts of such regulatory assets and liabilities and could adversely impact the Company's financial statements.

Contingent Obligations

The Company is subject to a number of federal and state laws and regulations, as well as other factors and conditions that subject it to environmental, litigation, income tax, and other risks. See FUTURE EARNINGS POTENTIAL herein and Note 3 to the financial statements for more information regarding certain of these contingencies. The Company periodically evaluates its exposure to such risks and, in accordance with GAAP, records reserves for those matters where a non-tax-related loss is considered probable and reasonably estimable and records a tax asset or liability if it is more likely than not that a tax position will be sustained. The adequacy of reserves can be significantly affected by external events or conditions that can be unpredictable; thus, the ultimate outcome of such matters could materially affect the Company's financial statements.

Pension and Other Postretirement Benefits

The Company's calculation of pension and other postretirement benefits expense is dependent on a number of assumptions. These assumptions include discount rates, healthcare cost trend rates, expected long-term return on plan assets, mortality rates, expected salary and wage increases, and other factors. Components of pension and other postretirement benefits expense include interest and service cost on the pension and other postretirement benefit plans, expected return on plan assets, and amortization of certain unrecognized costs and obligations. Actual results that differ from the assumptions utilized are accumulated and amortized over future periods and, therefore, generally affect recognized expense and the recorded obligation in future periods. While the Company believes that the assumptions used are appropriate, differences in actual experience or significant changes in assumptions would affect its pension and other postretirement benefits costs and obligations.

Key elements in determining the Company's pension and other postretirement benefit expense in accordance with GAAP are the expected long-term return on plan assets and the discount rate used to measure the benefit plan obligations and the periodic benefit plan expense for future periods. The expected long-term return on postretirement benefit plan assets is based on the Company's investment strategy, historical experience, and expectations for long-term rates of return that consider external actuarial advice. The Company determines the long-term return on plan assets by applying the long-term rate of expected returns on various asset classes to the Company's target asset allocation. The Company discounts the future cash flows related to its postretirement benefit plans using a single-point discount rate developed from the weighted average of market-observed yields for high quality fixed income securities with maturities that correspond to expected benefit payments.

A 25 basis point change in any significant assumption (discount rate, salaries, or long-term return on plan assets) would result in a $7 million or less change in total annual benefit expense and a $96 million or less change in projected obligations.

FINANCIAL CONDITION AND LIQUIDITY

Overview

The Company's financial condition remained stable at December 31, 2012. The Company's cash requirements primarily consist of funding ongoing operations, common stock dividends, capital expenditures, and debt maturities. Capital expenditures and other investing activities include investments to comply with environmental regulations and for restoration following major storms. Operating cash flows provide a substantial portion of the Company's cash needs. For the three-year period from 2013 through 2015, the Company's projected common stock dividends, capital expenditures, and debt maturities are expected to exceed operating cash flows. Projected capital expenditures in that period include investments to add environmental equipment for existing generating units and to expand and improve transmission and distribution facilities. The Company plans to finance future cash needs in excess of its operating cash flows primarily through debt and equity issuances. The Company intends to continue to monitor its access to short-term and long-term capital markets as well as its bank credit arrangements to meet future capital and liquidity needs. See "Sources of Capital," "Financing Activities," and "Capital Requirements and Contractual Obligations" herein for additional information.

The Company's investments in the qualified pension plan and the nuclear decommissioning trust funds increased in value as of December 31, 2012 as compared to December 31, 2011. No contributions to the qualified pension plan were made for the year ended December 31, 2012. The Company's funding obligations for the nuclear decommissioning trust fund are based on the site study, and the next study is expected to be conducted in 2013.

Net cash provided from operating activities totaled $1.4 billion for 2012, a decrease of $672 million as compared to 2011. The decrease in cash provided from operating activities was primarily due to an increase in fossil fuel stock, a decrease in deferred income taxes, and the timing of income tax payments and refunds associated with bonus depreciation. Net cash provided from operating activities in 2011 totaled $2.1 billion, an increase of $675 million as compared to 2010. The increase in cash provided from operating activities was primarily due to accrued taxes and deferred income taxes related to benefits associated with bonus depreciation, other current liabilities, accounts payable, and depreciation and amortization.

Net cash used for investing activities totaled $0.9 billion for 2012 and $1.0 billion for 2011 and 2010, primarily due to gross property additions to utility plant of $0.9 billion, $1.0 billion, and $0.9 billion for 2012, 2011, and 2010, respectively. In 2012, these additions were primarily due to gross property additions related to nuclear fuel and transmission, distribution, and steam generating equipment. In the prior years, gross property additions were primarily related to environmental mandates, construction of transmission and distribution facilities, replacement of steam generation equipment, and purchases of nuclear fuel.

Net cash used for financing activities totaled $649 million in 2012 primarily due to issuances, redemptions, and a maturity of senior notes, and payment of common stock dividends to Southern Company. Net cash used for financing activities totaled $869 million in 2011 primarily due to issuances, redemptions, and a maturity of debt securities and payment of higher common stock dividends. Net cash used for financing activities totaled $600 million in 2010 primarily due to the payment of common stock dividends. Fluctuations in cash flow from financing activities vary from year to year based on capital needs and the maturity or redemption of securities.

Significant balance sheet changes for 2012 include increases of $297 million in long-term debt, $269 million in property, plant, and equipment associated with routine property additions, $147 million in accumulated deferred income taxes related to bonus depreciation, $89 million in other regulatory assets, deferred, and $131 million in fossil fuel stock, at average cost, partially offset by decreases of $250 million of securities due within one year and $207 million in cash and cash equivalents.

The Company's ratio of common equity to total capitalization, including short-term debt, was 44.0% in 2012 and 43.9% in 2011. See Note 6 to the financial statements for additional information.

Sources of Capital

The Company plans to obtain the funds required for construction and other purposes from sources similar to those used in the past. The Company has primarily utilized funds from operating cash flows, short-term debt, security issuances, and equity contributions from Southern Company. However, the amount, type, and timing of any future financings, if needed, will depend upon prevailing market conditions, regulatory approval, and other factors.

Security issuances are subject to regulatory approval by the Alabama PSC. Additionally, with respect to the public offering of securities, the Company files registration statements with the Securities and Exchange Commission (SEC) under the Securities Act of 1933, as amended. The amounts of securities authorized by the Alabama PSC are continuously monitored and appropriate filings are made to ensure flexibility in the capital markets.

The Company obtains financing separately without credit support from any affiliate. See Note 6 to the financial statements under "Bank Credit Arrangements" for additional information. The Southern Company system does not maintain a centralized cash or money pool. Therefore, funds of the Company are not commingled with funds of any other company in the Southern Company system.

The Company's current liabilities sometimes exceed current assets because of the Company's debt due within one year and the periodic use of short-term debt as a funding source primarily to meet scheduled maturities of long-term debt, as well as cash needs, which can fluctuate significantly due to the seasonality of the business.

At December 31, 2012, the Company had approximately $137 million of cash and cash equivalents. Committed credit arrangements with banks at December 31, 2012 were as follows:

Expires[a]					Executable Term-Loans		Due Within One Year	
2013	2014	2016	Total	Unused	One Year	Two Years	Term Out	Not Term Out
			(in millions)					
$ 158	$ 350	$ 800	$ 1,308	$ 1,308	$ 56	$ —	$ 56	$ 102

(a) No credit arrangements expire in 2015.

See Note 6 to the financial statements under "Bank Credit Arrangements" for additional information.

Most of these arrangements contain covenants that limit debt levels and contain cross default provisions that are restricted only to the indebtedness (including guarantee obligations) of the Company. The Company is currently in compliance with all such covenants. The Company expects to renew its credit arrangements as needed, prior to expiration.

In addition, the Company has substantial cash flow from operating activities and access to the capital markets, including a commercial paper program, to meet liquidity needs. These credit arrangements provide liquidity support to the Company's variable rate pollution control revenue bonds and commercial paper borrowings. As of December 31, 2012, the Company had $793 million of outstanding pollution control revenue bonds requiring liquidity support.

The Company may meet short-term cash needs through its commercial paper program. The Company may also meet short-term cash needs through a Southern Company subsidiary organized to issue and sell commercial paper at the request and for the benefit of the Company and the other traditional operating companies. Proceeds from such issuances for the benefit of the Company are loaned directly to the Company. The obligations of each company under these arrangements are several and there is no cross-affiliate credit support.

Details of short-term borrowings were as follows:

	Short-term Debt at the End of the Period		Short-term Debt During the Period [a]		
	Amount Outstanding	Weighted Average Interest Rate	Average Outstanding	Weighted Average Interest Rate	Maximum Amount Outstanding
	(in millions)		*(in millions)*		*(in millions)*
December 31, 2012:					
Commercial paper	**$ —**	**—%**	**$ 6**	**0.2%**	**$ 57**
December 31, 2011:					
Commercial paper	$ —	—%	$ 20	0.2%	$ 255
December 31, 2010:					
Commercial paper	$ —	—%	$ 7	0.2%	$ 135

(a) Average and maximum amounts are based upon daily balances during the twelve-month periods ended December 31, 2012, 2011, and 2010.

Management believes that the need for working capital can be adequately met by utilizing commercial paper programs, lines of credit, and cash.

Financing Activities

In January 2012, the Company issued $250 million aggregate principal amount of Series 2012A 4.10% Senior Notes due January 15, 2042. The proceeds were used for general corporate purposes, including the Company's continuous construction program. The Company settled $100 million of interest rate swaps related to this issuance at a cost of $1 million. The cost is being amortized to interest expense, in earnings, over 10 years.

In March 2012, the Company redeemed approximately $1 million aggregate principal amount of The Industrial Development Board of the Town of West Jefferson Solid Waste Disposal Revenue Bonds (Alabama Power Company Miller Plant Project), Series 2008.

In April 2012, the Company redeemed $250 million aggregate principal amount of its Series 2007B 5.875% Senior Notes due April 1, 2047.

In October 2012, the Company issued $400 million aggregate principal amount of Series 2012B 0.550% Senior Notes due October 15, 2015. The proceeds were used to redeem $200 million aggregate principal amount of Series 2007C 6.00% Senior Insured Monthly Notes due October 15, 2037, and for general corporate purposes, including the Company's continuous construction program.

In December 2012, the Company issued $350 million aggregate principal amount of Series 2012C 3.85% Senior Notes due December 1, 2042. The proceeds, together with other funds of the Company, were used to pay, at maturity, $500 million aggregate amount of the Company's Series 2007D 4.85% Senior Notes due December 15, 2012. The Company settled $300 million of interest rate swaps related to the issuance of the Series 2012C Senior Notes at a cost of $35 million. The cost is being amortized to interest expense, in earnings, over 10 years.

In addition to any financings that may be necessary to meet capital requirements and contractual obligations, the Company plans to continue, when economically feasible, a program to retire higher-cost securities and replace these obligations with lower-cost capital if market conditions permit.

Credit Rating Risk

The Company does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. There are certain contracts that could require collateral, but not accelerated payment, in the event of a credit rating change to below BBB- and/or Baa3. These contracts are primarily for physical electricity purchases, fuel purchases, fuel transportation and storage, and energy price risk management. At December 31, 2012, the maximum potential collateral requirements under these contracts at a rating below BBB- and/or Baa3 were approximately $273 million. Included in these amounts are certain agreements that could require collateral in the event that one or more Southern Company system power pool participants has a credit rating change to below investment grade. Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. Additionally, any credit rating downgrade could impact the Company's ability to access capital markets, particularly the short-term debt market and the variable rate pollution control revenue bond market.

Market Price Risk

Due to cost-based rate regulation and other various cost recovery mechanisms, the Company continues to have limited exposure to market volatility in interest rates, commodity fuel prices, and prices of electricity. To manage the volatility attributable to these exposures, the Company nets the exposures, where possible, to take advantage of natural offsets and enters into various derivative transactions for the remaining exposures pursuant to the Company's policies in areas such as counterparty exposure and risk management practices. The Company's policy is that derivatives are to be used primarily for hedging purposes and mandates strict adherence to all applicable risk management policies. Derivative positions are monitored using techniques including, but not limited to, market valuation, value at risk, stress testing, and sensitivity analysis.

To mitigate future exposure to changes in interest rates, the Company enters into derivatives that have been designated as hedges. The weighted average interest rate on $984 million of long-term variable interest rate exposure that has not been hedged at January 1, 2013 was 0.80%. If the Company sustained a 100 basis point change in interest rates for all unhedged variable rate long-term debt, the change would affect annualized interest expense by approximately $10 million at January 1, 2013. See Note 1 to the financial statements under "Financial Instruments" and Note 11 to the financial statements for additional information.

To mitigate residual risks relative to movements in electricity prices, the Company enters into physical fixed-price contracts for the purchase and sale of electricity through the wholesale electricity market and, to a lesser extent, financial hedge contracts for natural gas purchases. The Company continues to manage a retail fuel hedging program implemented per the guidelines of the Alabama PSC. The Company had no material change in market risk exposure for the year ended December 31, 2012 when compared to the December 31, 2011 reporting period.

In addition, Rate ECR allows the recovery of specific costs associated with the sales of natural gas that become necessary due to operating considerations at the Company's electric generating facilities. Rate ECR also allows recovery of the cost of financial instruments used for hedging market price risk up to 75% of the budgeted annual amount of natural gas purchases. The Company may not engage in natural gas hedging activities that extend beyond a rolling 42-month window. Also, the premiums paid for natural gas financial options may not exceed 5% of the Company's natural gas budget for that year.

The changes in fair value of energy-related derivative contracts, substantially all of which are composed of regulatory hedges, for the years ended December 31 were as follows:

		2012 Changes		2011 Changes
		Fair Value		
		(in millions)		
Contracts outstanding at the beginning of the period, assets (liabilities), net	**$**	**(48)**	$	(38)
Contracts realized or settled		**46**		37
Current period changes[(a)]		**(11)**		(47)
Contracts outstanding at the end of the period, assets (liabilities), net	**$**	**(13)**	$	(48)

(a) Current period changes also include the changes in fair value of new contracts entered into during the period, if any.

The changes in the fair value positions of the energy-related derivative contracts, which are substantially all attributable to both the volume and the price of natural gas, for the years ended December 31 were as follows:

		2012 Changes		2011 Changes
		Fair Value		
		(in millions)		
Natural gas swaps	**$**	**30**	$	(5)
Natural gas options		**5**		(5)
Other energy-related derivatives		**—**		—
Total changes	**$**	**35**	$	(10)

The net hedge volumes of energy-related derivative contracts, for the years ended December 31 were as follows:

	2012	2011
	mmBtu* Volume	
	(in millions)	
Commodity – Natural gas swaps	**45**	30
Commodity – Natural gas options	**12**	9
Total hedge volume	**57**	39

*million British thermal units (mmBtu)

The weighted average swap contract cost above market prices was approximately $0.30 per mmBtu as of December 31, 2012 and $1.45 per mmBtu as of December 31, 2011. The change in option fair value is primarily attributable to the volatility of the market and the underlying change in the natural gas price. The majority of the natural gas hedge gains and losses are recovered through the Company's retail energy cost recovery clause.

At December 31, 2012 and 2011, substantially all of the Company's energy-related derivative contracts were designated as regulatory hedges and are related to the Company's fuel hedging program. Therefore, gains and losses are initially recorded as regulatory liabilities and assets, respectively, and then are included in fuel expense as they are recovered through the energy cost recovery clause. Certain other gains and losses on energy-related derivatives, designated as cash flow hedges, are initially deferred in other comprehensive income before being recognized in income in the same period as the hedged transaction. Gains and losses on energy-related derivative contracts that are not designated or fail to qualify as hedges are recognized in the statements of income as incurred and were not material for any year presented.

The Company uses over-the-counter contracts that are not exchange traded but are fair valued using prices which are market observable, and thus fall into Level 2. See Note 10 to the financial statements for further discussion of fair value measurements. The maturities of the energy-related derivative contracts, which are all Level 2 of the fair value hierarchy, at December 31, 2012 were as follows:

	Fair Value Measurements December 31, 2012		
	Total Fair Value	Maturity Year 1	Maturity Years 2&3
		(in millions)	
Level 1	$ —	$ —	$ —
Level 2	(13)	(12)	(1)
Level 3	—	—	—
Fair value of contracts outstanding at end of period	$ (13)	$ (12)	$ (1)

The Company is exposed to market price risk in the event of nonperformance by counterparties to energy-related and interest rate derivative contracts. The Company only enters into agreements and material transactions with counterparties that have investment grade credit ratings by Moody's Investors Service, Inc. and Standard & Poor's Ratings Services, a division of The McGraw Hill Companies, Inc., or with counterparties who have posted collateral to cover potential credit exposure. Therefore, the Company does not anticipate market risk exposure from nonperformance by the counterparties. For additional information, see Note 1 to the financial statements under "Financial Instruments" and Note 11 to the financial statements.

Capital Requirements and Contractual Obligations

The Company's construction program consists of a base level capital investment and capital expenditures to comply with existing environmental statutes and regulations, including the MATS rule. Over the next three years, the Company estimates spending, as part of its base level capital investment, $553 million on Plant Farley (including nuclear fuel), $895 million on distribution facilities, and $698 million on transmission additions. These base level capital investment amounts also include capital expenditures related to contractual purchase commitments for nuclear fuel and capital expenditures covered under long-term service agreements. Proposed water and coal combustion byproducts rules are not included in the construction program base level capital investment. The Company's base level construction program investments including investments to comply with existing environmental statutes and regulations and the estimated incremental compliance costs related to the proposed water and coal combustion byproducts rules over the 2013 through 2015 three-year period, based on the assumption that coal combustion byproducts will continue to be regulated as non-hazardous solid waste under the proposed rule, are estimated as follows:

	2013	2014	2015
Construction program:		*(in millions)*	
Base capital	$ 954	$ 1,117	$ 1,171
Existing environmental statutes and regulations, including the MATS rule	195	424	411
Total construction program base level capital investment	**$ 1,149**	**$ 1,541**	**$ 1,582**
Potential incremental environmental compliance investments:			
Proposed water and coal combustion byproducts rules	$ 5	$ 10	$ 160

See FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations" for additional information.

The construction program is subject to periodic review and revision, and actual construction costs may vary from these estimates because of numerous factors. These factors include: changes in business conditions; changes in load projections; changes in environmental statutes and regulations; the outcome of any legal challenges to the environmental rules; changes in generating plants, including unit retirements and replacements and adding or changing fuel sources at existing units, to meet regulatory requirements; changes in the expected environmental compliance program; changes in FERC rules and regulations; Alabama PSC approvals; changes in legislation; the cost and efficiency of construction labor, equipment, and materials; project scope and design changes; storm impacts; and the cost of capital. In addition, there can be no assurance that costs related to capital expenditures will be fully recovered.

In addition to the funds required for the Company's construction program, approximately $704 million will be required by the end of 2015 for maturities of long-term debt. The Company plans to continue, when economically feasible, to retire higher cost securities and replace these obligations with lower cost capital if market conditions permit.

As a result of NRC requirements, the Company has external trust funds for nuclear decommissioning costs; however, the Company currently has no additional funding requirements. For additional information, see Note 1 to the financial statements under "Nuclear Decommissioning." The Company has also established an external trust fund for postretirement benefits as ordered by the Alabama PSC. The cumulative effect of funding these items over an extended period will diminish internally funded capital for other purposes and may require the Company to seek capital from other sources. See Note 2 to the financial statements for additional information.

Other funding requirements related to obligations associated with scheduled maturities of long-term debt, as well as the related interest, derivative obligations, preferred and preference stock dividends, leases, and other purchase commitments are detailed in the contractual obligations table that follows. See Notes 1, 2, 5, 6, 7, and 11 to the financial statements for additional information.

Contractual Obligations

	2013	2014-2015	2016-2017	After 2017	Uncertain Timing[d]	Total
			(in millions)			
Long-term debt[a] —						
Principal	$ 250	$ 454	$ 761	$ 4,717	$ —	$ 6,182
Interest	250	472	457	3,420	—	4,599
Preferred and preference stock dividends[b]	39	79	79	—	—	197
Financial derivative obligations[c]	14	4	—	—	—	18
Operating leases	20	20	13	9	—	62
Unrecognized tax benefits[d]	—	—	—	—	31	31
Purchase commitments —						
Capital[e]	1,028	2,754	—	—	—	3,782
Fuel[f]	1,385	2,088	646	560	—	4,679
Purchased power[g]	39	106	112	525	—	782
Other[h]	43	82	38	32	—	195
Pension and other postretirement benefit plans[i]	18	36	—	—	—	54
Total	$ 3,086	$ 6,095	$ 2,106	$ 9,263	$ 31	$ 20,581

(a) All amounts are reflected based on final maturity dates. The Company plans to continue to retire higher-cost securities and replace these obligations with lower-cost capital if market conditions permit. Variable rate interest obligations are estimated based on rates as of January 1, 2013, as reflected in the statements of capitalization. Fixed rates include, where applicable, the effects of interest rate derivatives employed to manage interest rate risk.

(b) Preferred and preference stock do not mature; therefore, amounts are provided for the next five years only.

(c) For additional information, see Notes 1 and 11 to the financial statements.

(d) The timing related to the realization of $31 million in unrecognized tax benefits in individual years beyond 12 months cannot be reasonably and reliably estimated due to uncertainties in the timing of the effective settlement of tax positions. See Note 5 to the financial statements under "Unrecognized Tax Benefits" for additional information.

(e) The Company provides estimated capital expenditures for a three-year period, including estimated capital expenditures and compliance costs associated with existing environmental regulations, including the MATS rule. Such amounts exclude the Company's estimates of potential incremental environmental compliance investment to comply with proposed water and coal combustion byproducts rules, which are approximately $5 million, $10 million, and $160 million for years 2013, 2014, and 2015, respectively. These amounts also exclude contractual purchase commitments for nuclear fuel and capital expenditures covered under long-term service agreements, which are reflected separately. At December 31, 2012, significant purchase commitments were outstanding in connection with the construction program. See FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations" for additional information.

(f) Includes commitments to purchase coal, nuclear fuel, and natural gas, as well as the related transportation and storage. In most cases, these contracts contain provisions for price escalation, minimum purchase levels, and other financial commitments. Natural gas purchase commitments are based on various indices at the time of delivery. Amounts reflected for natural gas purchase commitments have been estimated based on the New York Mercantile Exchange future prices at December 31, 2012.

(g) Estimated minimum long-term obligations for various long-term commitments for the purchase of capacity and energy. Amounts are related to the Company's certificated PPAs which include MWs purchased from gas-fired and wind-powered facilities.

(h) Includes long-term service agreements and contracts for the procurement of limestone. Long-term service agreements include price escalation based on inflation indices.

(i) The Company forecasts contributions to the pension and other postretirement benefit plans over a three-year period. The Company anticipates no mandatory contributions to the qualified pension plan during the next three years. Amounts presented represent estimated benefit payments for the nonqualified pension plans, estimated non-trust benefit payments for the other postretirement benefit plans, and estimated contributions to the other postretirement benefit plan trusts, all of which will be made from the Company's corporate assets. See Note 2 to the financial statements for additional information related to the pension and other postretirement benefit plans, including estimated benefit payments. Certain benefit payments will be made through the related benefit plans. Other benefit payments will be made from the Company's corporate assets.

Cautionary Statement Regarding Forward Looking Statements

The Company's 2012 Annual Report contains forward-looking statements. Forward-looking statements include, among other things, statements concerning retail sales, retail rates, customer growth, economic recovery, fuel and environmental cost recovery and other rate actions, current and proposed environmental regulations and related estimated expenditures, access to sources of capital, projections for the qualified pension plan, postretirement benefit plan, and nuclear decommissioning trust fund contributions, financing activities, filings with state and federal regulatory authorities, impact of the Tax Relief Act, impact of the ATRA, estimated sales and purchases under new power sale and purchase agreements, and estimated construction and other expenditures. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "could," "should," "expects," "plans," "anticipates," "believes," "estimates," "projects," "predicts," "potential," or "continue" or the negative of these terms or other similar terminology. There are various factors that could cause actual results to differ materially from those suggested by the forward-looking statements; accordingly, there can be no assurance that such indicated results will be realized. These factors include:

- the impact of recent and future federal and state regulatory changes, including legislative and regulatory initiatives regarding deregulation and restructuring of the electric utility industry, environmental laws including regulation of water, coal combustion byproducts, and emissions of sulfur, nitrogen, carbon, soot, particulate matter, hazardous air pollutants, including mercury, and other substances, financial reform legislation, and also changes in tax and other laws and regulations to which the Company is subject, as well as changes in application of existing laws and regulations;
- current and future litigation, regulatory investigations, proceedings, or inquiries, including FERC matters, pending EPA civil action against the Company, and Internal Revenue Service and state tax audits;
- the effects, extent, and timing of the entry of additional competition in the markets in which the Company operates;
- variations in demand for electricity, including those relating to weather, the general economy and recovery from the recent recession, population and business growth (and declines), the effects of energy conservation measures, and any potential economic impacts resulting from federal fiscal decisions;
- available sources and costs of fuels;
- effects of inflation;
- ability to control costs and avoid cost overruns during the development and construction of facilities;
- investment performance of the Company's employee benefit plans and nuclear decommissioning trust funds;
- advances in technology;
- state and federal rate regulations and the impact of pending and future rate cases and negotiations, including rate actions relating to fuel and other cost recovery mechanisms;
- the inherent risks involved in operating nuclear generating facilities, including environmental, health, regulatory, natural disaster, terrorism, or financial risks;
- internal restructuring or other restructuring options that may be pursued;
- potential business strategies, including acquisitions or dispositions of assets or businesses, which cannot be assured to be completed or beneficial to the Company;
- the ability of counterparties of the Company to make payments as and when due and to perform as required;
- the ability to obtain new short- and long-term contracts with wholesale customers;
- the direct or indirect effect on the Company's business resulting from terrorist incidents and the threat of terrorist incidents, including cyber intrusion;
- interest rate fluctuations and financial market conditions and the results of financing efforts, including the Company's credit ratings;
- the impacts of any potential U.S. credit rating downgrade or other sovereign financial issues, including impacts on interest rates, access to capital markets, impacts on currency exchange rates, counterparty performance, and the economy in general;
- the ability of the Company to obtain additional generating capacity at competitive prices;
- catastrophic events such as fires, earthquakes, explosions, floods, hurricanes, droughts, pandemic health events such as influenzas, or other similar occurrences;
- the direct or indirect effects on the Company's business resulting from incidents affecting the U.S. electric grid or operation of generating resources;
- the effect of accounting pronouncements issued periodically by standard setting bodies; and

- other factors discussed elsewhere herein and in other reports (including the Form 10-K) filed by the Company from time to time with the SEC.

The Company expressly disclaims any obligation to update any forward-looking statements.

STATEMENTS OF INCOME
For the Years Ended December 31, 2012, 2011, and 2010
Alabama Power Company 2012 Annual Report

	2012	2011	2010
		(in millions)	
Operating Revenues:			
Retail revenues	**$ 4,933**	$ 4,972	$ 5,076
Wholesale revenues, non-affiliates	**277**	287	465
Wholesale revenues, affiliates	**111**	244	236
Other revenues	**199**	199	199
Total operating revenues	**5,520**	5,702	5,976
Operating Expenses:			
Fuel	**1,503**	1,679	1,851
Purchased power, non-affiliates	**73**	73	72
Purchased power, affiliates	**182**	198	208
Other operations and maintenance	**1,287**	1,262	1,418
Depreciation and amortization	**639**	637	606
Taxes other than income taxes	**340**	339	332
Total operating expenses	**4,024**	4,188	4,487
Operating Income	**1,496**	1,514	1,489
Other Income and (Expense):			
Allowance for equity funds used during construction	**19**	22	36
Interest income	**16**	18	17
Interest expense, net of amounts capitalized	**(287)**	(299)	(303)
Other income (expense), net	**(24)**	(30)	(30)
Total other income and (expense)	**(276)**	(289)	(280)
Earnings Before Income Taxes	**1,220**	1,225	1,209
Income taxes	**477**	478	463
Net Income	**743**	747	746
Dividends on Preferred and Preference Stock	**39**	39	39
Net Income After Dividends on Preferred and Preference Stock	**$ 704**	$ 708	$ 707

The accompanying notes are an integral part of these financial statements.

STATEMENTS OF COMPREHENSIVE INCOME
For the Years Ended December 31, 2012, 2011, and 2010
Alabama Power Company 2012 Annual Report

	2012	2011	2010
		(in millions)	
Net Income	**$ 743**	$ 747	$ 746
Other comprehensive income (loss):			
Qualifying hedges:			
Changes in fair value, net of tax of $(7), $(5), and $-, respectively	**(11)**	(9)	—
Reclassification adjustment for amounts included in net income, net of tax of $1, $(1), and $(1), respectively	**2**	(2)	(2)
Total other comprehensive income (loss)	**(9)**	(11)	(2)
Comprehensive Income	**$ 734**	$ 736	$ 744

The accompanying notes are an integral part of these financial statements.

STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2012, 2011, and 2010
Alabama Power Company 2012 Annual Report

	2012	2011	2010
		(in millions)	
Operating Activities:			
Net income	$ 743	$ 747	$ 746
Adjustments to reconcile net income to net cash provided from operating activities —			
Depreciation and amortization, total	767	749	694
Deferred income taxes	164	459	410
Allowance for equity funds used during construction	(19)	(22)	(36)
Pension, postretirement, and other employee benefits	(11)	(32)	(15)
Pension and postretirement funding	(10)	(9)	(55)
Stock based compensation expense	9	6	5
Natural disaster reserve	3	34	52
Other, net	(27)	(41)	(27)
Changes in certain current assets and liabilities —			
-Receivables	23	18	(29)
-Fossil fuel stock	(132)	47	(1)
-Materials and supplies	(21)	(33)	(20)
-Other current assets	(4)	(6)	(4)
-Accounts payable	(77)	11	(54)
-Accrued taxes	(12)	157	(140)
-Accrued compensation	(3)	(12)	28
-Other current liabilities	(17)	(25)	(181)
Net cash provided from operating activities	1,376	2,048	1,373
Investing Activities:			
Property additions	(867)	(977)	(903)
Investment in restricted cash from pollution control bonds	1	4	—
Distribution of restricted cash from pollution control bonds	—	13	18
Nuclear decommissioning trust fund purchases	(194)	(350)	(237)
Nuclear decommissioning trust fund sales	193	349	236
Cost of removal net of salvage	(33)	(28)	(44)
Change in construction payables	12	(9)	(45)
Other investing activities	(46)	9	(12)
Net cash used for investing activities	(934)	(989)	(987)
Financing Activities:			
Proceeds —			
Capital contributions from parent company	27	12	28
Senior notes issuances	1,000	700	250
Redemptions —			
Pollution control revenue bonds	(1)	(4)	—
Senior notes	(950)	(750)	(250)
Payment of preferred and preference stock dividends	(39)	(39)	(39)
Payment of common stock dividends	(684)	(774)	(586)
Other financing activities	(2)	(14)	(3)
Net cash used for financing activities	(649)	(869)	(600)
Net Change in Cash and Cash Equivalents	(207)	190	(214)
Cash and Cash Equivalents at Beginning of Year	344	154	368
Cash and Cash Equivalents at End of Year	$ 137	$ 344	$ 154
Supplemental Cash Flow Information:			
Cash paid during the period for —			
Interest (net of $7, $9 and $14 capitalized, respectively)	$ 273	$ 286	$ 288
Income taxes (net of refunds)	309	(139)	188
Noncash transactions - accrued property additions at year-end	31	19	28

The accompanying notes are an integral part of these financial statements.

BALANCE SHEETS
At December 31, 2012 and 2011
Alabama Power Company 2012 Annual Report

Assets	2012	2011
		(in millions)
Current Assets:		
Cash and cash equivalents	$ 137	$ 344
Restricted cash	—	1
Receivables —		
Customer accounts receivable	321	332
Unbilled revenues	138	126
Under recovered regulatory clause revenues	23	—
Other accounts and notes receivable	42	35
Affiliated companies	55	79
Accumulated provision for uncollectible accounts	(8)	(10)
Fossil fuel stock, at average cost	475	344
Materials and supplies, at average cost	395	375
Vacation pay	61	59
Prepaid expenses	81	74
Other regulatory assets, current	24	44
Other current assets	13	11
Total current assets	1,757	1,814
Property, Plant, and Equipment:		
In service	21,407	20,809
Less accumulated provision for depreciation	7,761	7,344
Plant in service, net of depreciation	13,646	13,465
Nuclear fuel, at amortized cost	354	330
Construction work in progress	438	374
Total property, plant, and equipment	14,438	14,169
Other Property and Investments:		
Equity investments in unconsolidated subsidiaries	53	62
Nuclear decommissioning trusts, at fair value	605	540
Miscellaneous property and investments	78	73
Total other property and investments	736	675
Deferred Charges and Other Assets:		
Deferred charges related to income taxes	525	532
Prepaid pension costs	—	59
Deferred under recovered regulatory clause revenues	11	48
Other regulatory assets, deferred	1,083	994
Other deferred charges and assets	162	186
Total deferred charges and other assets	1,781	1,819
Total Assets	$ 18,712	$ 18,477

The accompanying notes are an integral part of these financial statements.

BALANCE SHEETS
At December 31, 2012 and 2011
Alabama Power Company 2012 Annual Report

Liabilities and Stockholder's Equity	2012	2011
		(in millions)
Current Liabilities:		
Securities due within one year	$ 250	$ 500
Accounts payable —		
Affiliated	191	203
Other	318	322
Customer deposits	85	85
Accrued taxes —		
Accrued income taxes	5	32
Other accrued taxes	33	34
Accrued interest	62	63
Accrued vacation pay	50	48
Accrued compensation	94	95
Liabilities from risk management activities	14	54
Other regulatory liabilities, current	3	18
Other current liabilities	38	38
Total current liabilities	1,143	1,492
Long-Term Debt (See accompanying statements)	5,929	5,632
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	3,404	3,257
Deferred credits related to income taxes	79	83
Accumulated deferred investment tax credits	141	149
Employee benefit obligations	321	343
Asset retirement obligations	589	553
Other cost of removal obligations	759	703
Other regulatory liabilities, deferred	183	156
Other deferred credits and liabilities	81	82
Total deferred credits and other liabilities	5,557	5,326
Total Liabilities	12,629	12,450
Redeemable Preferred Stock (See accompanying statements)	342	342
Preference Stock (See accompanying statements)	343	343
Common Stockholder's Equity (See accompanying statements)	5,398	5,342
Total Liabilities and Stockholder's Equity	$ 18,712	$ 18,477
Commitments and Contingent Matters (See notes)		

The accompanying notes are an integral part of these financial statements.

STATEMENTS OF CAPITALIZATION
At December 31, 2012 and 2011
Alabama Power Company 2012 Annual Report

	2012	2011	2012	2011
	(in millions)		*(percent of total)*	
Long-Term Debt:				
Long-term debt payable to affiliated trusts —				
Variable rate (3.41% at 1/1/13) due 2042	**$ 206**	$ 206		
Long-term notes payable —				
4.85% due 2012	**—**	500		
5.80% due 2013	**250**	250		
0.55% due 2015	**400**	—		
5.20% due 2016	**200**	200		
5.50% to 5.55% due 2017	**525**	525		
3.375% to 6.125% due 2019-2047	**3,450**	3,300		
Total long-term notes payable	**4,825**	4,775		
Other long-term debt —				
Pollution control revenue bonds —				
0.58% to 5.00% due 2034	**367**	367		
Variable rate (0.13% at 1/1/13) due 2015	**54**	54		
Variable rates (0.13% to 0.17% at 1/1/13) due 2017	**36**	36		
Variable rates (0.08% to 0.20% at 1/1/13) due 2021-2038	**694**	694		
Total other long-term debt	**1,151**	1,151		
Unamortized debt premium (discount), net	**(3)**	—		
Total long-term debt (annual interest requirement — $250 million)	**6,179**	6,132		
Less amount due within one year	**250**	500		
Long-term debt excluding amount due within one year	**5,929**	5,632	**49.4%**	48.4%

STATEMENTS OF CAPITALIZATION (continued)
At December 31, 2012 and 2011
Alabama Power Company 2012 Annual Report

	2012	2011	2012	2011
	(in millions)		*(percent of total)*	
Redeemable Preferred Stock:				
Cumulative redeemable preferred stock				
$100 par or stated value — 4.20% to 4.92%				
Authorized — 3,850,000 shares				
Outstanding — 475,115 shares	**48**	48		
$1 par value — 5.20% to 5.83%				
Authorized — 27,500,000 shares				
Outstanding — 12,000,000 shares: $25 stated value				
(annual dividend requirement — $18 million)	**294**	294		
Total redeemable preferred stock	**342**	342	**2.8**	2.9
Preference Stock:				
Authorized — 40,000,000 shares				
Outstanding — $1 par value — 5.63% to 6.50%				
— 14,000,000 shares				
(non-cumulative) $25 stated value				
(annual dividend requirement — $21 million)	**343**	343	**2.9**	2.9
Common Stockholder's Equity:				
Common stock, par value $40 per share —				
Authorized: 40,000,000 shares				
Outstanding: 30,537,500 shares	**1,222**	1,222		
Paid-in capital	**2,227**	2,182		
Retained earnings	**1,976**	1,956		
Accumulated other comprehensive income (loss)	**(27)**	(18)		
Total common stockholder's equity	**5,398**	5,342	**44.9**	45.8
Total Capitalization	**$ 12,012**	$ 11,659	**100.0%**	100.0%

The accompanying notes are an integral part of these financial statements.

STATEMENTS OF COMMON STOCKHOLDER'S EQUITY
For the Years Ended December 31, 2012, 2011, and 2010
Alabama Power Company 2012 Annual Report

	Number of Common Shares Issued	Common Stock	Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
			(in millions)			
Balance at December 31, 2009	31	$ 1,222	$ 2,119	$ 1,901	$ (5)	$ 5,237
Net income after dividends on preferred and preference stock	—	—	—	707	—	707
Capital contributions from parent company	—	—	37	—	—	37
Other comprehensive income (loss)	—	—	—	—	(2)	(2)
Cash dividends on common stock	—	—	—	(586)	—	(586)
Balance at December 31, 2010	31	1,222	2,156	2,022	(7)	5,393
Net income after dividends on preferred and preference stock	—	—	—	708	—	708
Capital contributions from parent company	—	—	26	—	—	26
Other comprehensive income (loss)	—	—	—	—	(11)	(11)
Cash dividends on common stock	—	—	—	(774)	—	(774)
Balance at December 31, 2011	**31**	**1,222**	**2,182**	**1,956**	**(18)**	**5,342**
Net income after dividends on preferred and preference stock	—	—	—	**704**	—	**704**
Capital contributions from parent company	—	—	**45**	—	—	**45**
Other comprehensive income (loss)	—	—	—	—	**(9)**	**(9)**
Cash dividends on common stock	—	—	—	**(684)**	—	**(684)**
Balance at December 31, 2012	**31**	**$ 1,222**	**$ 2,227**	**$ 1,976**	**$ (27)**	**$ 5,398**

The accompanying notes are an integral part of these financial statements.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

General

Alabama Power Company (the Company) is a wholly owned subsidiary of The Southern Company (Southern Company), which is the parent company of four traditional operating companies, Southern Power Company (Southern Power), Southern Company Services, Inc. (SCS), Southern Communications Services, Inc. (SouthernLINC Wireless), Southern Company Holdings, Inc. (Southern Holdings), Southern Nuclear Operating Company, Inc. (Southern Nuclear), and other direct and indirect subsidiaries. The traditional operating companies – the Company, Georgia Power Company (Georgia Power), Gulf Power Company (Gulf Power), and Mississippi Power Company (Mississippi Power) – are vertically integrated utilities providing electric service in four Southeastern states. The Company operates as a vertically integrated utility providing electricity to retail and wholesale customers within its traditional service territory located in the State of Alabama in addition to wholesale customers in the Southeast. Southern Power constructs, acquires, owns, and manages generation assets, including renewable energy projects, and sells electricity at market-based rates in the wholesale market. SCS, the system service company, provides, at cost, specialized services to Southern Company and its subsidiary companies. SouthernLINC Wireless provides digital wireless communications for use by Southern Company and its subsidiary companies and also markets these services to the public and provides fiber cable services within the Southeast. Southern Holdings is an intermediate holding company subsidiary primarily for Southern Company's investments in leveraged leases. Southern Nuclear operates and provides services to the Southern Company system's nuclear power plants, including the Company's Plant Farley.

The equity method is used for subsidiaries in which the Company has significant influence but does not control and for variable interest entities (VIEs) where the Company has an equity investment, but is not the primary beneficiary.

The Company is subject to regulation by the Federal Energy Regulatory Commission (FERC) and the Alabama Public Service Commission (PSC). The Company follows generally accepted accounting principles (GAAP) in the U.S. and complies with the accounting policies and practices prescribed by its regulatory commissions. The preparation of financial statements in conformity with GAAP requires the use of estimates, and the actual results may differ from those estimates. Certain prior years' data presented in the financial statements have been reclassified to conform to the current year presentation.

Affiliate Transactions

The Company has an agreement with SCS under which the following services are rendered to the Company at direct or allocated cost: general and design engineering, operations, purchasing, accounting, finance and treasury, tax, information technology, marketing, auditing, insurance and pension administration, human resources, systems and procedures, digital wireless communications, and other services with respect to business and operations and power pool transactions. Costs for these services amounted to $340 million, $347 million, and $371 million during 2012, 2011, and 2010, respectively. Cost allocation methodologies used by SCS prior to the repeal of the Public Utility Holding Company Act of 1935, as amended, were approved by the Securities and Exchange Commission (SEC). Subsequently, additional cost allocation methodologies have been reported to the FERC and management believes they are reasonable. The FERC permits services to be rendered at cost by system service companies.

The Company has an agreement with Southern Nuclear under which the following nuclear-related services are rendered to the Company at cost: general executive and advisory services, general operations, management and technical services, administrative services including procurement, accounting, employee relations, systems and procedures services, strategic planning and budgeting services, and other services with respect to business and operations. Costs for these services amounted to $218 million, $215 million, and $218 million during 2012, 2011, and 2010, respectively.

The Company jointly owns Plant Greene County with Mississippi Power. The Company has an agreement with Mississippi Power under which the Company operates Plant Greene County, and Mississippi Power reimburses the Company for its proportionate share of non-fuel expenses, which were $12 million in 2012, $12 million in 2011, and $11 million in 2010. Also, Mississippi Power reimburses the Company for any direct fuel purchases delivered from one of the Company's transfer facilities, which were $28 million in 2012, $21 million in 2011, and $16 million in 2010. See Note 4 for additional information.

Due to the expiration of the Plant Harris power purchase agreement (PPA) with Southern Power in 2010, no purchased power costs or fuel costs were recognized in 2012 or 2011 associated with this PPA. Additionally, the Company recorded no prepaid capacity expenses in 2012 or 2011. The Company's purchased power costs from Plant Harris in 2010 totaled $15 million. The Company also provided the fuel, at cost, associated with the PPA totaling $21 million in 2010. See Note 7 under "Fuel and Purchased Power Agreements" for additional information.

The Company has an agreement with Gulf Power under which the Company will make transmission system upgrades to ensure firm delivery of energy under a non-affiliate PPA. In 2009, Gulf Power entered into a PPA for the capacity and energy from a combined cycle plant located in Autauga County, Alabama. The total cost committed by the Company related to the upgrades is approximately $38 million in 2012, $22 million in 2013, and $29 million in 2014. The Company expects to recover a majority of these costs through a tariff with Gulf Power until 2023. The remainder of these costs will be recovered through normal rate mechanisms.

The Company provides incidental services to and receives such services from other Southern Company subsidiaries which are generally minor in duration and amount. Except as described herein, the Company neither provided nor received any material services to or from affiliates in 2012, 2011, or 2010.

Also, see Note 4 for information regarding the Company's ownership in, a PPA, and a gas pipeline ownership agreement with Southern Electric Generating Company (SEGCO).

The traditional operating companies, including the Company and Southern Power, may jointly enter into various types of wholesale energy, natural gas, and certain other contracts, either directly or through SCS as agent. Each participating company may be jointly and severally liable for the obligations incurred under these agreements. See Note 7 under "Fuel and Purchased Power Agreements" for additional information.

New Accounting Pronouncements

In June 2011, the Financial Accounting Standards Board (FASB) issued guidance, ASU 2011-05, *Presentation of Comprehensive Income*, requiring companies to present the total of comprehensive income, the components of net income, and the components of other comprehensive income, in a single continuous statement of comprehensive income or in two separate but consecutive statements. In October 2012, the FASB issued additional guidance, ASU 2012-04, *Technical Corrections and Improvements* (ASU 2012-04), in which it clarified that those companies presenting consecutive statements must begin the statement of comprehensive income with net income. The Company retroactively adopted the guidance in ASU 2012-04 beginning with its financial statements for the three years ended December 31, 2012, 2011, and 2010.

Regulatory Assets and Liabilities

The Company is subject to the provisions of the FASB in accounting for the effects of rate regulation. Regulatory assets represent probable future revenues associated with certain costs that are expected to be recovered from customers through the ratemaking process. Regulatory liabilities represent probable future reductions in revenues associated with amounts that are expected to be credited to customers through the ratemaking process.

Regulatory assets and (liabilities) reflected in the balance sheets at December 31 relate to:

	2012	2011	Note
	(in millions)		
Deferred income tax charges	$ 525	$ 532	(a,k)
Loss on reacquired debt	93	84	(b)
Vacation pay	61	59	(c,j)
Under/(over) recovered regulatory clause revenues	34	47	(d)
Fuel hedging (realized and unrealized) losses	18	48	(e)
Other regulatory assets	51	46	(f,l)
Asset retirement obligations	(64)	(35)	(a)
Other cost of removal obligations	(759)	(703)	(a)
Deferred income tax credits	(79)	(83)	(a)
Fuel hedging (realized and unrealized) gains	(5)	(1)	(e)
Mine reclamation and remediation	(8)	(8)	(g)
Nuclear outage	33	38	(d)
Natural disaster reserve	(103)	(110)	(h)
Other regulatory liabilities	(5)	(20)	(d,l)
Retiree benefit plans	911	822	(i,j)
Total regulatory assets (liabilities), net	$ 703	$ 716	

Note: The recovery and amortization periods for these regulatory assets and (liabilities) are as follows:

(a) Asset retirement and removal assets and liabilities are recorded, deferred income tax assets are recovered, and deferred income tax liabilities are amortized over the related property lives, which may range up to 50 years. Asset retirement and removal assets and liabilities will be settled and trued up following completion of the related activities.

(b) Recovered over the remaining life of the original issue, which may range up to 50 years.

(c) Recorded as earned by employees and recovered as paid, generally within one year. This includes both vacation and banked holiday pay.

(d) Recorded and recovered or amortized as approved or accepted by the Alabama PSC over periods not exceeding five years.

(e) Fuel hedging assets and liabilities are recorded over the life of the underlying hedged purchase contracts, which generally do not exceed three years. Upon final settlement, actual costs incurred are recovered through the energy cost recovery clause.

(f) Recorded as accepted by the Alabama PSC. Capitalized upon initialization of related construction projects, if applicable.

(g) Recorded as accepted by the Alabama PSC. Mine reclamation and remediation liabilities will be settled following completion of the related activities.

(h) Utilized as storm restoration and potential reliability-related expenses are incurred, as approved by the Alabama PSC.

(i) Recovered and amortized over the average remaining service period which may range up to 15 years. See Note 2 for additional information.

(j) Not earning a return as offset in rate base by a corresponding asset or liability.

(k) Included in the deferred income tax charges is $21 million for the retiree Medicare drug subsidy, which is recovered and amortized, as approved by the Alabama PSC, over the average remaining service period which may range up to 15 years.

(l) Recovered and amortized as approved or accepted by the Alabama PSC over the life of the contract.

In the event that a portion of the Company's operations is no longer subject to applicable accounting rules for rate regulation, the Company would be required to write off to income or reclassify to accumulated other comprehensive income (OCI) related regulatory assets and liabilities that are not specifically recoverable through regulated rates. In addition, the Company would be required to determine if any impairment to other assets, including plant, exists and write down the assets, if impaired, to their fair values. All regulatory assets and liabilities are reflected in rates. See Note 3 under "Retail Regulatory Matters" for additional information.

Revenues

Wholesale capacity revenues are generally recognized on a levelized basis over the appropriate contract period. Energy and other revenues are recognized as services are provided. Unbilled revenues related to retail sales are accrued at the end of each fiscal period. Electric rates for the Company include provisions to adjust billings for fluctuations in fuel costs, fuel hedging, the energy component of purchased power costs, and certain other costs. Revenues are adjusted for differences between these actual costs and amounts billed in current regulated rates. Under or over recovered regulatory clause revenues are recorded in the balance sheets and are recovered or returned to customers through adjustments to the billing factors. The Company continuously monitors the under/over recovered balances and files for revised rates as required or when management deems appropriate, depending on the rate. See Note 3 under "Retail Regulatory Matters – Energy Cost Recovery" and "Retail Regulatory Matters – Rate CNP" for additional information.

The Company has a diversified base of customers. No single customer or industry comprises 10% or more of revenues. For all periods presented, uncollectible accounts averaged less than 1% of revenues.

Fuel Costs

Fuel costs are expensed as the fuel is used. Fuel expense generally includes fuel transportation costs and the cost of purchased emissions allowances as they are used. Fuel expense also includes the amortization of the cost of nuclear fuel and a charge, based on nuclear generation, for the permanent disposal of spent nuclear fuel. See Note 3 under "Nuclear Fuel Disposal Costs" for additional information.

Income and Other Taxes

The Company uses the liability method of accounting for deferred income taxes and provides deferred income taxes for all significant income tax temporary differences. Investment tax credits utilized are deferred and amortized to income over the average life of the related property. Taxes that are collected from customers on behalf of governmental agencies to be remitted to these agencies are presented net on the statements of income.

In accordance with accounting standards related to the uncertainty in income taxes, the Company recognizes tax positions that are "more likely than not" of being sustained upon examination by the appropriate taxing authorities. See Note 5 under "Unrecognized Tax Benefits" for additional information.

Property, Plant, and Equipment

Property, plant, and equipment is stated at original cost less any regulatory disallowances and impairments. Original cost includes: materials; labor; minor items of property; appropriate administrative and general costs; payroll-related costs such as taxes, pensions, and other benefits; and the interest capitalized and cost of equity funds used during construction.

The Company's property, plant, and equipment in service consisted of the following at December 31:

		2012		2011
		(in millions)		
Generation	$	**11,110**	$	10,982
Transmission		**3,137**		2,998
Distribution		**5,714**		5,517
General		**1,434**		1,300
Plant acquisition adjustment		**12**		12
Total plant in service	$	**21,407**	$	20,809

The cost of replacements of property, exclusive of minor items of property, is capitalized. The cost of maintenance, repairs, and replacement of minor items of property is charged to other operations and maintenance expense as incurred or performed with the exception of nuclear refueling costs, which are recorded in accordance with specific Alabama PSC orders.

In 2010, the Alabama PSC approved the Company's request to stop accruing for nuclear refueling outage costs in advance of the refueling outages when the most recent 18 month cycle ended in December 2010 and to begin deferring nuclear outage expenses. The amortization will begin after each outage has occurred and the associated outage expenses are known.

During 2011, the Company deferred $38 million of nuclear outage expenses associated with the fall 2011 outage and began the first 18-month amortization cycle for expenses in January 2012. The Company deferred an additional $31 million of nuclear outage expenses associated with the spring 2012 outage and began the second amortization cycle in July 2012. The total unamortized deferred nuclear outage expense balance of $33 million is included in the 2012 balance sheet as a regulatory asset.

Depreciation and Amortization

Depreciation of the original cost of utility plant in service is provided primarily by using composite straight-line rates, which approximated 3.2% in 2012, 3.3% in 2011, and 3.3% in 2010. Depreciation studies are conducted periodically to update the composite rates and the information is provided to the Alabama PSC and the FERC. When property subject to depreciation is retired or otherwise disposed of in the normal course of business, its original cost, together with the cost of removal, less salvage, is charged to accumulated depreciation. For other property dispositions, the applicable cost and accumulated depreciation are removed from the balance sheet accounts, and a gain or loss is recognized. Minor items of property included in the original cost of the plant are retired when the related property unit is retired.

In 2011, the Company submitted a depreciation study to the FERC and received authorization to use the recommended rates beginning January 2012. The study was also provided to the Alabama PSC.

Asset Retirement Obligations and Other Costs of Removal

Asset retirement obligations are computed as the present value of the ultimate costs for an asset's future retirement and are recorded in the period in which the liability is incurred. The costs are capitalized as part of the related long-lived asset and depreciated over the asset's useful life. The Company has received accounting guidance from the Alabama PSC allowing the continued accrual of other future retirement costs for long-lived assets that the Company does not have a legal obligation to retire. Accordingly, the accumulated removal costs for these obligations are reflected in the balance sheets as a regulatory liability.

The liability for asset retirement obligations primarily relates to the decommissioning of the Company's nuclear facility, Plant Farley. In addition, the Company has retirement obligations related to various landfill sites, underground storage tanks, asbestos removal, and disposal of polychlorinated biphenyls in certain transformers. The Company also has identified retirement obligations related to certain transmission and distribution facilities and certain wireless communication towers. However, liabilities for the removal of these assets have not been recorded because the range of time over which the Company may settle these obligations is unknown and cannot be reasonably estimated. The Company will continue to recognize in the statements of income allowed removal costs in accordance with its regulatory treatment. Any differences between costs recognized in accordance with accounting standards related to asset retirement and environmental obligations and those reflected in rates are recognized as either a regulatory asset or liability, as ordered by the Alabama PSC, and are reflected in the balance sheets. See "Nuclear Decommissioning" herein for additional information on amounts included in rates.

Details of the asset retirement obligations included in the balance sheets are as follows:

	2012	2011
	(in millions)	
Balance at beginning of year	$ 553	$ 520
Liabilities incurred	—	—
Liabilities settled	(1)	(2)
Accretion	37	35
Balance at end of year	$ 589	$ 553

Nuclear Decommissioning

The Nuclear Regulatory Commission (NRC) requires licensees of commercial nuclear power reactors to establish a plan for providing reasonable assurance of funds for future decommissioning. The Company has external trust funds (Funds) to comply with the NRC's regulations. Use of the Funds is restricted to nuclear decommissioning activities. The Funds are managed and invested in accordance with applicable requirements of various regulatory bodies, including the NRC, the FERC, and the Alabama PSC, as well as the Internal Revenue Service (IRS). The Funds are required to be held by one or more trustees with an individual net worth of at least $100 million. The FERC requires the Funds' managers to exercise the standard of care in investing that a "prudent investor" would use in the same circumstances. The FERC regulations also require that the Funds' managers may not invest in any securities of the utility for which it manages funds or its affiliates, except for investments tied to market indices or other mutual funds. While the Company is allowed to prescribe an overall investment policy to the Funds' managers, the Company and its affiliates are not allowed to engage in the day-to-day management of the Funds or to mandate individual investment decisions. Day-to-day management of the investments in the Funds is delegated to unrelated third party managers with oversight by the management of the Company. The Funds' managers are authorized, within certain investment guidelines, to actively buy and sell securities at their own discretion in order to maximize the return on the Funds' investments. The Funds are invested in a tax-efficient manner in a diversified mix of equity and fixed income securities and are reported as trading securities.

The Company records the investment securities held in the Funds at fair value, as disclosed in Note 10, as management believes that fair value best represents the nature of the Funds. Gains and losses, whether realized or unrealized, are recorded in the regulatory liability for asset retirement obligations in the balance sheets and are not included in net income or OCI. Fair value adjustments and realized gains and losses are determined on a specific identification basis.

At December 31, 2012, investment securities in the Funds totaled $604 million consisting of equity securities of $438 million, debt securities of $156 million, and $10 million of other securities. At December 31, 2011, investment securities in the Funds totaled $539 million consisting of equity securities of $382 million, debt securities of $146 million, and $11 million of other securities. These amounts exclude receivables related to investment income and pending investment sales and payables related to pending investment purchases.

Sales of the securities held in the Funds resulted in cash proceeds of $193 million, $349 million, and $236 million in 2012, 2011, and 2010, respectively, all of which were reinvested. For 2012, fair value increases, including reinvested interest and dividends and excluding the Funds' expenses, were $70 million, of which $4 million related to realized gains and $50 million related to unrealized gains related to securities held in the Funds at December 31, 2012. For 2011, fair value increases, including reinvested interest and dividends and excluding the Funds' expenses, were $6 million, of which $41 million related to realized gains and $51 million related to unrealized losses related to securities held in the Funds at December 31, 2011. For 2010, fair value increases, including reinvested interest and dividends and excluding the Funds' expenses, were $65 million, of which $31 million related to securities held in the Funds at December 31, 2010. While the investment securities held in the Funds are reported as trading securities, the Funds continue to be managed with a long-term focus. Accordingly, all purchases and sales within the Funds are presented separately in the statements of cash flows as investing cash flows, consistent with the nature of and purpose for which the securities were acquired.

Amounts previously recorded in internal reserves are being transferred into the Funds over periods approved by the Alabama PSC. The NRC's minimum external funding requirements are based on a generic estimate of the cost to decommission only the radioactive portions of a nuclear unit based on the size and type of reactor. The Company has filed a plan with the NRC designed to ensure that, over time, the deposits and earnings of the Funds will provide the minimum funding amounts prescribed by the NRC.

At December 31, 2012, the accumulated provisions for decommissioning were as follows:

		(in millions)
External trust funds	$	604
Internal reserves		22
Total	$	626

Site study cost is the estimate to decommission a facility as of the site study year. The estimated costs of decommissioning based on the most current study performed in 2008 for Plant Farley are as follows:

Decommissioning periods:	
Beginning year	2037
Completion year	2065

		(in millions)
Site study costs:		
Radiated structures	$	1,060
Non-radiated structures		72
Total site study costs	$	1,132

The decommissioning cost estimates are based on prompt dismantlement and removal of the plant from service. The actual decommissioning costs may vary from the above estimates because of changes in the assumed date of decommissioning, changes in NRC requirements, or changes in the assumptions used in making these estimates.

For ratemaking purposes, the Company's decommissioning costs are based on the site study. Significant assumptions used to determine these costs for ratemaking were an inflation rate of 4.5% and a trust earnings rate of 7.0%. The next site study is expected to be conducted in 2013.

Amounts previously contributed to the Funds are currently projected to be adequate to meet the decommissioning obligations. The Company will continue to provide site specific estimates of the decommissioning costs and related projections of funds in the external trust to the Alabama PSC and, if necessary, would seek the Alabama PSC's approval to address any changes in a manner consistent with the NRC and other applicable requirements.

Allowance for Funds Used During Construction

In accordance with regulatory treatment, the Company records allowance for funds used during construction (AFUDC), which represents the estimated debt and equity costs of capital funds that are necessary to finance the construction of new regulated facilities. While cash is not realized currently from such allowance, AFUDC increases the revenue requirement over the service life of the plant through a higher rate base and higher depreciation. The equity component of AFUDC is not included in calculating taxable income. All current construction costs are included in retail rates. The composite rate used to determine the amount of AFUDC was 9.4% in 2012, 9.2% in 2011, and 9.4% in 2010. AFUDC, net of income taxes, as a percent of net income after dividends on preferred and preference stock was 3.3% in 2012, 3.9% in 2011, and 6.3% in 2010.

Impairment of Long-Lived Assets and Intangibles

The Company evaluates long-lived assets for impairment when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. The determination of whether an impairment has occurred is based on either a specific regulatory disallowance or an estimate of undiscounted future cash flows attributable to the assets, as compared with the carrying value of the assets. If an impairment has occurred, the amount of the impairment recognized is determined by either the amount of regulatory disallowance or by estimating the fair value of the assets and recording a loss if the carrying value is greater than the fair value. For assets identified as held for sale, the carrying value is compared to the estimated fair value less the cost to sell in order to determine if an impairment loss is required. Until the assets are disposed of, their estimated fair value is re-evaluated when circumstances or events change.

Natural Disaster Reserve

Based on an order from the Alabama PSC, the Company maintains a reserve for operations and maintenance expenses to cover the cost of damages from major storms to its transmission and distribution facilities. The order approves a separate monthly Rate Natural Disaster Reserve (Rate NDR) charge to customers consisting of two components. The first component is intended to establish and maintain a reserve balance for future storms and is an on-going part of customer billing. The second component of the Rate NDR charge is intended to allow recovery of any existing deferred storm-related operations and maintenance costs and any future reserve deficits over a 24-month period. The Alabama PSC order gives the Company authority to record a deficit balance in the Natural Disaster Reserve (NDR) when costs of storm damage exceed any established reserve balance. Absent

further Alabama PSC approval, the maximum total Rate NDR charge consisting of both components is $10 per month per non-residential customer account and $5 per month per residential customer account. The Company has the authority, based on an order from the Alabama PSC, to accrue certain additional amounts as circumstances warrant. The order allows for reliability-related expenditures to be charged against the additional accruals when the NDR balance exceeds $75 million. The Company may designate a portion of the NDR to reliability-related expenditures as a part of an annual budget process for the following year or during the current year for identified unbudgeted reliability-related expenditures that are incurred. Accruals that have not been designated can be used to offset storm charges. Additional accruals to the NDR will enhance the Company's ability to deal with the financial effects of future natural disasters, promote system reliability, and offset costs retail customers would otherwise bear.

As revenue from the Rate NDR charge is recognized, an equal amount of operations and maintenance expenses related to the NDR will also be recognized. As a result, the Rate NDR charge will not have an effect on net income but will impact operating cash flows. See Note 3 under "Natural Disaster Reserve" herein for additional information.

Cash and Cash Equivalents

For purposes of the financial statements, temporary cash investments are considered cash equivalents. Temporary cash investments are securities with original maturities of 90 days or less.

Materials and Supplies

Generally, materials and supplies include the average cost of transmission, distribution, and generating plant materials. Materials are charged to inventory when purchased and then expensed or capitalized to plant, as appropriate, at weighted average cost when installed.

Fuel Inventory

Fuel inventory includes the average cost of coal, natural gas, oil, transportation, and emissions allowances. Fuel is charged to inventory when purchased and then expensed, at weighted average cost, as used and recovered by the Company through energy cost recovery rates approved by the Alabama PSC. Emissions allowances granted by the Environmental Protection Agency (EPA) are included in inventory at zero cost.

Financial Instruments

The Company uses derivative financial instruments to limit exposure to fluctuations in interest rates, the prices of certain fuel purchases, and electricity purchases and sales. All derivative financial instruments are recognized as either assets or liabilities (included in "Other" or shown separately as "Risk Management Activities") and are measured at fair value. See Note 10 for additional information. Substantially all of the Company's bulk energy purchases and sales contracts that meet the definition of a derivative are excluded from fair value accounting requirements because they qualify for the "normal" scope exception, and are accounted for under the accrual method. Other derivative contracts qualify as cash flow hedges of anticipated transactions or are recoverable through the Alabama PSC-approved fuel hedging program. This results in the deferral of related gains and losses in OCI or regulatory assets and liabilities, respectively, until the hedged transactions occur. Any material ineffectiveness arising from cash flow hedges is recognized currently in net income. Other derivative contracts are marked to market through current period income and are recorded on a net basis in the statements of income. See Note 11 for additional information.

The Company does not offset fair value amounts recognized for multiple derivative instruments executed with the same counterparty under a master netting arrangement. Additionally, the Company had no outstanding collateral repayment obligations or rights to reclaim collateral arising from derivative instruments recognized at December 31, 2012.

The Company is exposed to losses related to financial instruments in the event of counterparties' nonperformance. The Company has established controls to determine and monitor the creditworthiness of counterparties in order to mitigate the Company's exposure to counterparty credit risk.

Comprehensive Income

The objective of comprehensive income is to report a measure of all changes in common stock equity of an enterprise that result from transactions and other economic events of the period other than transactions with owners. Comprehensive income consists of net income, changes in the fair value of qualifying cash flow hedges, and reclassifications for amounts included in net income.

Variable Interest Entities

The primary beneficiary of a VIE is required to consolidate the VIE when it has both the power to direct the activities of the VIE that most significantly impact the VIE's economic performance and the obligation to absorb losses or the right to receive benefits from the VIE that could potentially be significant to the VIE.

The Company has established a wholly-owned trust to issue preferred securities. See Note 6 under "Long-Term Debt Payable to an Affiliated Trust" for additional information. However, the Company is not considered the primary beneficiary of the trust. Therefore, the investment in the trust is reflected as other investments, and the related loan from the trust is reflected as long-term debt in the balance sheets.

2. RETIREMENT BENEFITS

The Company has a defined benefit, trusteed, pension plan covering substantially all employees. This qualified pension plan is funded in accordance with requirements of the Employee Retirement Income Security Act of 1974, as amended (ERISA). No contributions to the qualified pension plan were made for the year ended December 31, 2012. No mandatory contributions to the qualified pension plan are anticipated for the year ending December 31, 2013. The Company also provides certain defined benefit pension plans for a selected group of management and highly compensated employees. Benefits under these non-qualified pension plans are funded on a cash basis. In addition, the Company provides certain medical care and life insurance benefits for retired employees through other postretirement benefit plans. The Company funds its other postretirement trusts to the extent required by the Alabama PSC and the FERC. For the year ending December 31, 2013, other postretirement trust contributions are expected to total approximately $4 million.

Actuarial Assumptions

The weighted average rates assumed in the actuarial calculations used to determine both the benefit obligations as of the measurement date and the net periodic costs for the pension and other postretirement benefit plans for the following year are presented below. Net periodic benefit costs were calculated in 2009 for the 2010 plan year using discount rates for the pension plans and the other postretirement benefit plans of 5.93% and 5.84%, respectively, and an annual salary increase of 4.18%.

	2012	2011	2010
Discount rate:			
Pension plans	**4.27%**	4.98%	5.52%
Other postretirement benefit plans	**4.06**	4.88	5.41
Annual salary increase	**3.59**	3.84	3.84
Long-term return on plan assets:			
Pension plans	**8.20**	8.45	8.45
Other postretirement benefit plans	**7.19**	7.39	7.43

The Company estimates the expected rate of return on pension plan and other postretirement benefit plan assets using a financial model to project the expected return on each current investment portfolio. The analysis projects an expected rate of return on each of seven different asset classes in order to arrive at the expected return on the entire portfolio relying on each trust's target asset allocation and reasonable capital market assumptions. The financial model is based on four key inputs: anticipated returns by asset class (based in part on historical returns), each trust's target asset allocation, an anticipated inflation rate, and the projected impact of a periodic rebalancing of each trust's portfolio.

An additional assumption used in measuring the accumulated other postretirement benefit obligations (APBO) is the weighted average medical care cost trend rate. The weighted average medical care cost trend rates used in measuring the APBO as of December 31, 2012 were as follows:

	Initial Cost Trend Rate	Ultimate Cost Trend Rate	Year That Ultimate Rate Is Reached
Pre-65	8.00%	5.00%	2020
Post-65 medical	6.00	5.00	2020
Post-65 prescription	6.00	5.00	2020

An annual increase or decrease in the assumed medical care cost trend rate of 1% would affect the APBO and the service and interest cost components at December 31, 2012 as follows:

	1 Percent Increase	1 Percent Decrease
	(in millions)	
Benefit obligation	$ 32	$ (27)
Service and interest costs	2	(1)

Pension Plans

The total accumulated benefit obligation for the pension plans was $2.0 billion at December 31, 2012 and $1.8 billion at December 31, 2011. Changes in the projected benefit obligations and the fair value of plan assets during the plan years ended December 31, 2012 and 2011 were as follows:

	2012	2011
	(in millions)	
Change in benefit obligation		
Benefit obligation at beginning of year	$ 1,932	$ 1,779
Service cost	44	43
Interest cost	94	96
Benefits paid	(90)	(88)
Actuarial loss	238	102
Balance at end of year	2,218	1,932
Change in plan assets		
Fair value of plan assets at beginning of year	1,885	1,933
Actual return on plan assets	274	32
Employer contributions	8	8
Benefits paid	(90)	(88)
Fair value of plan assets at end of year	2,077	1,885
Accrued liability	$ (141)	$ (47)

At December 31, 2012, the projected benefit obligations for the qualified and non-qualified pension plans were $2.1 billion and $121 million, respectively. All pension plan assets are related to the qualified pension plan.

Amounts recognized in the balance sheets at December 31, 2012 and 2011 related to the Company's pension plans consist of the following:

	2012	2011
	(in millions)	
Prepaid pension costs	$ —	$ 59
Other regulatory assets, deferred	822	727
Other current liabilities	(8)	(7)
Employee benefit obligations	(133)	(99)

Presented below are the amounts included in regulatory assets at December 31, 2012 and 2011 related to the defined benefit pension plans that had not yet been recognized in net periodic pension cost along with the estimated amortization of such amounts for 2013.

	2012	2011	Estimated Amortization in 2013
		(in millions)	
Prior service cost	$ 26	$ 33	$ 7
Net (gain) loss	796	694	52
Other regulatory assets, deferred	$ 822	$ 727	

The changes in the balance of regulatory assets related to the defined benefit pension plans for the years ended December 31, 2012 and 2011 are presented in the following table:

	Regulatory Assets
	(in millions)
Balance at December 31, 2010	$ 497
Net (gain) loss	243
Change in prior service costs	—
Reclassification adjustments:	
Amortization of prior service costs	(9)
Amortization of net gain (loss)	(4)
Total reclassification adjustments	(13)
Total change	230
Balance at December 31, 2011	$ 727
Net (gain) loss	125
Change in prior service costs	—
Reclassification adjustments:	
Amortization of prior service costs	(7)
Amortization of net gain (loss)	(23)
Total reclassification adjustments	(30)
Total change	95
Balance at December 31, 2012	$ 822

Components of net periodic pension cost (income) were as follows:

	2012	2011	2010
		(in millions)	
Service cost	$ 44	$ 43	$ 41
Interest cost	94	96	97
Expected return on plan assets	(162)	(173)	(168)
Recognized net (gain) loss	23	4	2
Net amortization	7	9	9
Net periodic pension cost (income)	$ 6	$ (21)	$ (19)

Net periodic pension cost (income) is the sum of service cost, interest cost, and other costs netted against the expected return on plan assets. The expected return on plan assets is determined by multiplying the expected rate of return on plan assets and the market-related value of plan assets. In determining the market-related value of plan assets, the Company has elected to amortize changes in the market value of all plan assets over five years rather than recognize the changes immediately. As a result, the accounting value of plan assets that is used to calculate the expected return on plan assets differs from the current fair value of the plan assets.

Future benefit payments reflect expected future service and are estimated based on assumptions used to measure the projected benefit obligation for the pension plans. At December 31, 2012, estimated benefit payments were as follows:

	Benefit Payments
	(in millions)
2013	$ 99
2014	104
2015	108
2016	112
2017	117
2018 to 2022	637

Other Postretirement Benefits

Changes in the APBO and in the fair value of plan assets during the plan years ended December 31, 2012 and 2011 were as follows:

	2012	2011
	(in millions)	
Change in benefit obligation		
Benefit obligation at beginning of year	$ 470	$ 454
Service cost	5	5
Interest cost	22	24
Benefits paid	(24)	(27)
Actuarial loss	15	11
Plan amendments	—	—
Retiree drug subsidy	2	3
Balance at end of year	490	470
Change in plan assets		
Fair value of plan assets at beginning of year	315	323
Actual return on plan assets	39	5
Employer contributions	11	11
Benefits paid	(22)	(24)
Fair value of plan assets at end of year	343	315
Accrued liability	$ (147)	$ (155)

Amounts recognized in the balance sheets at December 31, 2012 and 2011 related to the Company's other postretirement benefit plans consist of the following:

	2012	2011
	(in millions)	
Regulatory assets	$ 89	$ 96
Employee benefit obligations	(147)	(155)

Presented below are the amounts included in regulatory assets at December 31, 2012 and 2011 related to the other postretirement benefit plans that had not yet been recognized in net periodic other postretirement benefit cost along with the estimated amortization of such amounts for 2013.

	2012	2011	Estimated Amortization in 2013
		(in millions)	
Prior service cost	$ 22	$ 26	$ 4
Net (gain) loss	67	68	2
Transition obligation	—	2	—
Regulatory assets	$ 89	$ 96	

The changes in the balance of regulatory assets related to the other postretirement benefit plans for the plan years ended December 31, 2012 and 2011 are presented in the following table:

	Regulatory Assets
	(in millions)
Balance at December 31, 2010	$ 72
Net (gain) loss	31
Change in prior service costs/transition obligation	—
Reclassification adjustments:	
Amortization of transition obligation	(3)
Amortization of prior service costs	(4)
Amortization of net gain (loss)	—
Total reclassification adjustments	(7)
Total change	24
Balance at December 31, 2011	$ 96
Net (gain) loss	**(1)**
Change in prior service costs/transition obligation	—
Reclassification adjustments:	
Amortization of transition obligation	**(2)**
Amortization of prior service costs	**(4)**
Amortization of net gain (loss)	—
Total reclassification adjustments	**(6)**
Total change	**(7)**
Balance at December 31, 2012	**$ 89**

Components of the other postretirement benefit plans' net periodic cost were as follows:

	2012	2011	2010
		(in millions)	
Service cost	**$ 5**	$ 5	$ 6
Interest cost	**22**	24	26
Expected return on plan assets	**(23)**	(25)	(25)
Net amortization	**6**	7	7
Net postretirement cost	**$ 10**	$ 11	$ 14

Future benefit payments, including prescription drug benefits, reflect expected future service and are estimated based on assumptions used to measure the APBO for the other postretirement benefit plans. Estimated benefit payments are reduced by drug subsidy receipts expected as a result of the Medicare Prescription Drug, Improvement, and Modernization Act of 2003 as follows:

	Benefit Payments	Subsidy Receipts	Total
		(in millions)	
2013	$ 30	$ (3)	$ 27
2014	32	(4)	28
2015	33	(4)	29
2016	34	(4)	30
2017	35	(5)	30
2018 to 2022	176	(26)	150

Benefit Plan Assets

Pension plan and other postretirement benefit plan assets are managed and invested in accordance with all applicable requirements, including ERISA and the Internal Revenue Code of 1986, as amended (Internal Revenue Code). The Company's investment policies for both the pension plan and the other postretirement benefit plans cover a diversified mix of assets, including equity and fixed income securities, real estate, and private equity. Derivative instruments are used primarily to gain efficient exposure to the various asset classes and as hedging tools. The Company minimizes the risk of large losses primarily through diversification but also monitors and manages other aspects of risk.

The composition of the Company's pension plan and other postretirement benefit plan assets as of December 31, 2012 and 2011, along with the targeted mix of assets for each plan, is presented below:

	Target	2012	2011
Pension plan assets:			
Domestic equity	26%	**28%**	29%
International equity	25	**24**	25
Fixed income	23	**27**	23
Special situations	3	**1**	—
Real estate investments	14	**13**	14
Private equity	9	**7**	9
Total	100%	**100%**	100%
Other postretirement benefit plan assets:			
Domestic equity	44%	**46%**	41%
International equity	20	**20**	14
Domestic fixed income	24	**28**	38
Special situations	1	**—**	—
Real estate investments	8	**4**	4
Private equity	3	**2**	3
Total	100%	**100%**	100%

The investment strategy for plan assets related to the Company's qualified pension plan is to be broadly diversified across major asset classes. The asset allocation is established after consideration of various factors that affect the assets and liabilities of the pension plan including, but not limited to, historical and expected returns, volatility, correlations of asset classes, the current level of assets and liabilities, and the assumed growth in assets and liabilities. Because a significant portion of the liability of the pension plan is long-term in nature, the assets are invested consistent with long-term investment expectations for return and risk. To manage the actual asset class exposures relative to the target asset allocation, the Company employs a formal rebalancing

program. As additional risk management, external investment managers and service providers are subject to written guidelines to ensure appropriate and prudent investment practices.

Investment Strategies

Detailed below is a description of the investment strategies for each major asset category for the pension and other postretirement benefit plans disclosed above:

- ***Domestic equity.*** A mix of large and small capitalization stocks with generally an equal distribution of value and growth attributes, managed both actively and through passive index approaches.
- ***International equity.*** A mix of growth stocks and value stocks with both developed and emerging market exposure, managed both actively and through passive index approaches.
- ***Fixed income.*** A mix of domestic and international bonds.
- ***Trust-owned life insurance (TOLI).*** Investments of the Company's taxable trusts aimed at minimizing the impact of taxes on the portfolio.
- ***Special situations.*** Investments in opportunistic strategies with the objective of diversifying and enhancing returns and exploiting short-term inefficiencies as well as investments in promising new strategies of a longer-term nature.
- ***Real estate investments.*** Investments in traditional private market, equity-oriented investments in real properties (indirectly through pooled funds or partnerships) and in publicly traded real estate securities.
- ***Private equity.*** Investments in private partnerships that invest in private or public securities typically through privately-negotiated and/or structured transactions, including leveraged buyouts, venture capital, and distressed debt.

Benefit Plan Asset Fair Values

Following are the fair value measurements for the pension plan and the other postretirement benefit plan assets as of December 31, 2012 and 2011. The fair values presented are prepared in accordance with GAAP. For purposes of determining the fair value of the pension plan and other postretirement benefit plan assets and the appropriate level designation, management relies on information provided by the plan's trustee. This information is reviewed and evaluated by management with changes made to the trustee information as appropriate.

Valuation methods of the primary fair value measurements disclosed in the following tables are as follows:

- **Investments in equity securities:** Investments in equity securities such as common stocks, American depositary receipts, and real estate investment trusts that trade on a public exchange are classified as Level 1 investments and are valued at the closing price in the active market. Equity investments with unpublished prices (i.e. pooled funds) are valued as Level 2, when the underlying holdings used to value the investment are comprised of Level 1 or Level 2 equity securities.
- **Investments in fixed income securities:** Investments in fixed income securities are generally classified as Level 2 investments and are valued based on prices reported in the market place. Additionally, the value of fixed income securities takes into consideration certain items such as broker quotes, spreads, yield curves, interest rates, and discount rates that apply to the term of a specific instrument.
- **Investments in TOLI**: Investments in TOLI policies are classified as Level 2 investments and are valued based on the underlying investments held in the policy's separate account. The underlying assets are equity and fixed income pooled funds that are comprised of Level 1 and Level 2 securities.
- **Investments in private equity and real estate:** Investments in private equity and real estate are generally classified as Level 3 as the underlying assets typically do not have observable inputs. The fund manager values the assets using various inputs and techniques depending on the nature of the underlying investments. In the case of private equity, techniques may include purchase multiples for comparable transactions, comparable public company trading multiples, and discounted cash flow analysis. Real estate managers generally use prevailing market capitalization rates, recent sales of comparable investments, and independent third-party appraisals to value underlying real estate investments. The fair value of partnerships is determined by aggregating the value of the underlying assets.

The fair values of pension plan assets as of December 31, 2012 and 2011 are presented below. These fair value measurements exclude cash, receivables related to investment income, pending investments sales, and payables related to pending investment purchases. Assets that are considered special situations investments, primarily real estate investments and private equities, are presented in the tables below based on the nature of the investment.

	Fair Value Measurements Using			
As of December 31, 2012:	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Total**
		(in millions)		
Assets:				
Domestic equity*	$ 304	$ 175	$ —	$ 479
International equity*	238	256	—	494
Fixed income:				
U.S. Treasury, government, and agency bonds	—	135	—	135
Mortgage- and asset-backed securities	—	33	—	33
Corporate bonds	—	230	1	231
Pooled funds	—	104	—	104
Cash equivalents and other	1	143	—	144
Real estate investments	67	—	220	287
Private equity	—	—	155	155
Total	$ 610	$ 1,076	$ 376	$ 2,062

* Level 1 securities consist of actively traded stocks while Level 2 securities consist of pooled funds. Management believes that the portfolio is well-diversified with no significant concentrations of risk.

As of December 31, 2011:	Fair Value Measurements Using: Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
		(in millions)		
Assets:				
Domestic equity*	$ 320	$ 148	$ —	$ 468
International equity*	329	94	—	423
Fixed income:				
U.S. Treasury, government, and agency bonds	—	120	—	120
Mortgage- and asset-backed securities	—	37	—	37
Corporate bonds	—	232	1	233
Pooled funds	—	105	—	105
Cash equivalents and other	—	39	—	39
Real estate investments	61	—	217	278
Private equity	—	—	161	161
Total	$ 710	$ 775	$ 379	$ 1,864

* Level 1 securities consist of actively traded stocks while Level 2 securities consist of pooled funds. Management believes that the portfolio is well-diversified with no significant concentrations of risk.

Changes in the fair value measurement of the Level 3 items in the pension plan assets valued using significant unobservable inputs for the years ended December 31, 2012 and 2011 were as follows:

	2012		2011	
	Real Estate Investments	Private Equity	Real Estate Investments	Private Equity
		(in millions)		
Beginning balance	**$ 217**	**$ 161**	$ 191	$ 180
Actual return on investments:				
Related to investments held at year end	**2**	—	16	(3)
Related to investments sold during the year	**1**	**2**	6	9
Total return on investments	**3**	**2**	22	6
Purchases, sales, and settlements	**—**	**(8)**	4	(25)
Transfers into/out of Level 3	—	—	—	—
Ending balance	**$ 220**	**$ 155**	$ 217	$ 161

The fair values of other postretirement benefit plan assets as of December 31, 2012 and 2011 are presented below. These fair value measurements exclude cash, receivables related to investment income, pending investments sales, and payables related to pending investment purchases. Assets that are considered special situations investments, primarily real estate investments and private equities, are presented in the tables below based on the nature of the investment.

As of December 31, 2012:	Fair Value Measurements Using: Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
		(in millions)		
Assets:				
Domestic equity*	$ 62	$ 9	$ —	$ 71
International equity*	12	13	—	25
Fixed income:				
U.S. Treasury, government, and agency bonds	—	7	—	7
Mortgage- and asset-backed securities	—	2	—	2
Corporate bonds	—	11	—	11
Pooled funds	—	5	—	5
Cash equivalents and other	—	19	—	19
Trust-owned life insurance	—	178	—	178
Real estate investments	4	—	11	15
Private equity	—	—	8	8
Total	$ 78	$ 244	$ 19	$ 341

* Level 1 securities consist of actively traded stocks while Level 2 securities consist of pooled funds. Management believes that the portfolio is well-diversified with no significant concentrations of risk.

As of December 31, 2011:	Fair Value Measurements Using: Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
		(in millions)		
Assets:				
Domestic equity*	$ 57	$ 8	$ —	$ 65
International equity*	17	5	—	22
Fixed income:				
U.S. Treasury, government, and agency bonds	—	9	—	9
Mortgage- and asset-backed securities	—	2	—	2
Corporate bonds	—	12	—	12
Pooled funds	—	5	—	5
Cash equivalents and other	—	19	—	19
Trust-owned life insurance	—	160	—	160
Real estate investments	4	—	11	15
Private equity	—	—	8	8
Total	$ 78	$ 220	$ 19	$ 317

* Level 1 securities consist of actively traded stocks while Level 2 securities consist of pooled funds. Management believes that the portfolio is well-diversified with no significant concentrations of risk.

Changes in the fair value measurement of the Level 3 items in the other postretirement benefit plan assets valued using significant unobservable inputs for the years ended December 31, 2012 and 2011 were as follows:

	2012		2011	
	Real Estate Investments	Private Equity	Real Estate Investments	Private Equity
	(in millions)			
Beginning balance	$ 11	$ 8	$ 10	$ 9
Actual return on investments:				
Related to investments held at year end	—	—	1	—
Related to investments sold during the year	—	—	—	—
Total return on investments	—	—	1	—
Purchases, sales, and settlements	—	—	—	(1)
Transfers into/out of Level 3	—	—	—	—
Ending balance	$ 11	$ 8	$ 11	$ 8

Employee Savings Plan

The Company also sponsors a 401(k) defined contribution plan covering substantially all employees. The Company provides an 85% matching contribution on up to 6% of an employee's base salary. Total matching contributions made to the plan for 2012, 2011, and 2010 were $19 million, $18 million, and $18 million, respectively.

3. CONTINGENCIES AND REGULATORY MATTERS

General Litigation Matters

The Company is subject to certain claims and legal actions arising in the ordinary course of business. In addition, the Company's business activities are subject to extensive governmental regulation related to public health and the environment, such as regulation of air emissions and water discharges. Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements such as air quality and water standards, has increased generally throughout the U.S. In particular, personal injury, property damage, and other claims for damages alleged to have been caused by carbon dioxide and other emissions, coal combustion byproducts, and alleged exposure to hazardous materials, and/or requests for injunctive relief in connection with such matters, have become more frequent. The ultimate outcome of such pending or potential litigation against the Company cannot be predicted at this time; however, for current proceedings not specifically reported herein, management does not anticipate that the ultimate liabilities, if any, arising from such current proceedings would have a material effect on the Company's financial statements.

Environmental Matters

New Source Review Actions

In 1999, the EPA brought a civil action in the U.S. District Court for the Northern District of Georgia against certain Southern Company subsidiaries, including the Company, alleging that these subsidiaries had violated the New Source Review (NSR) provisions of the Clean Air Act and related state laws at certain coal-fired generating facilities. The EPA alleged NSR violations at five coal-fired generating facilities operated by the Company and three coal-fired generating facilities operated by Georgia Power. The civil action sought penalties and injunctive relief, including an order requiring installation of the best available control technology at the affected units. The case against Georgia Power was administratively closed in 2001 and has not been reopened. After the Company was dismissed from the original action, the EPA filed a separate action in 2001 against the Company in the U.S. District Court for the Northern District of Alabama.

In 2006, the U.S. District Court for the Northern District of Alabama entered a consent decree, resolving claims relating to the alleged NSR violations at Plant Miller. In 2010, the EPA dismissed five of its eight remaining claims against the Company, leaving only three claims, including one relating to a unit co-owned by Mississippi Power. In March 2011, the U.S. District Court for the Northern District of Alabama granted the Company summary judgment on all remaining claims and dismissed the case with prejudice. That judgment is on appeal to the U.S. Court of Appeals for the Eleventh Circuit. On February 23, 2012, the EPA filed a motion in the U.S. District Court for the Northern District of Alabama seeking vacatur of the judgment and recusal of the judge in the case involving the Company.

The Company believes it complied with applicable laws and regulations in effect at the time the work in question took place. The Clean Air Act authorizes maximum civil penalties of $25,000 to $37,500 per day, per violation, depending on the date of the alleged violation. An adverse outcome could require substantial capital expenditures that cannot be determined at this time and could possibly require payment of substantial penalties. Such expenditures could affect future results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates. The ultimate outcome of this matter cannot be determined at this time.

Climate Change Litigation

Kivalina Case

In 2008, the Native Village of Kivalina and the City of Kivalina filed a lawsuit in the U.S. District Court for the Northern District of California against several electric utilities (including Southern Company), several oil companies, and a coal company. The plaintiffs allege that the village is being destroyed by erosion allegedly caused by global warming that the plaintiffs attribute to emissions of greenhouse gases by the defendants. The plaintiffs assert claims for public and private nuisance and contend that some of the defendants (including Southern Company) acted in concert and are therefore jointly and severally liable for the plaintiffs' damages. The suit seeks damages for lost property values and for the cost of relocating the village, which is alleged to be $95 million to $400 million. In 2009, the U.S. District Court for the Northern District of California granted the defendants' motions to dismiss the case. On September 21, 2012, the U.S. Court of Appeals for the Ninth Circuit upheld the U.S. District Court for the Northern District of California's dismissal of the case. On November 27, 2012, the U.S. Court of Appeals for the Ninth Circuit denied the plaintiffs' request for review of the decision. On February 25, 2013, the plaintiffs filed a petition for writ of certiorari with the U.S. Supreme Court. Southern Company believes that these claims are without merit. While Southern Company believes the likelihood of loss is remote based on existing case law, it is not possible to predict with certainty whether the Company will incur any liability in connection with this matter. The ultimate outcome of this matter cannot be determined at this time.

Hurricane Katrina Case

In 2005, immediately following Hurricane Katrina, a lawsuit was filed in the U.S. District Court for the Southern District of Mississippi by Ned Comer on behalf of Mississippi residents seeking recovery for property damage and personal injuries caused by Hurricane Katrina. In 2006, the plaintiffs amended the complaint to include Southern Company and many other electric utilities, oil companies, chemical companies, and coal producers. The plaintiffs allege that the defendants contributed to climate change, which contributed to the intensity of Hurricane Katrina. In 2007, the U.S. District Court for the Southern District of Mississippi dismissed the case. On appeal to the U.S. Court of Appeals for the Fifth Circuit, a three-judge panel reversed the U.S. District Court for the Southern District of Mississippi, holding that the case could proceed, but, on rehearing, the full U.S. Court of Appeals for the Fifth Circuit dismissed the plaintiffs' appeal, resulting in reinstatement of the decision of the U.S. District Court for the Southern District of Mississippi in favor of the defendants. In May 2011, the plaintiffs filed an amended version of their class action complaint, arguing that the earlier dismissal was on procedural grounds and under Mississippi law the plaintiffs have a right to re-file. The amended complaint was also filed against numerous chemical, coal, oil, and utility companies, including the Company. On March 20, 2012, the U.S. District Court for the Southern District of Mississippi dismissed the plaintiffs' amended complaint. On April 16, 2012, the plaintiffs appealed the case to the U.S. Court of Appeals for the Fifth Circuit. The Company believes that these claims are without merit. While the Company believes the likelihood of loss is remote based on existing case law, it is not possible to predict with certainty whether the Company will incur any liability in connection with this matter. The ultimate outcome of this matter cannot be determined at this time.

Environmental Remediation

The Company must comply with environmental laws and regulations that cover the handling and disposal of waste and releases of hazardous substances. Under these various laws and regulations, the Company could incur substantial costs to clean up properties. The Company conducts studies to determine the extent of any required cleanup and has recognized in its financial statements the costs to clean up known sites. Amounts for cleanup and ongoing monitoring costs were not material for any year presented. The Company may be liable for some or all required cleanup costs for additional sites that may require environmental remediation.

Nuclear Fuel Disposal Costs

Acting through the U.S. Department of Energy (DOE) and pursuant to the Nuclear Waste Policy Act of 1982, the U.S. government entered into a contract with the Company that requires the DOE to dispose of spent nuclear fuel and high level radioactive waste generated at Plant Farley. The DOE failed to timely perform and has yet to commence the performance of its contractual and statutory obligation to dispose of spent nuclear fuel beginning no later than January 31, 1998. Consequently, the Company has pursued and continues to pursue legal remedies against the U.S. government for its partial breach of contract.

As a result of the first lawsuit, the Company recovered approximately $17 million, representing substantially all of the Company's direct costs of the expansion of spent nuclear fuel storage facilities at Plant Farley from 1998 through 2004. In April 2012, the award was credited to cost of service for the benefit of customers.

In 2008, the Company filed a second lawsuit against the U.S. government for the costs of continuing to store spent nuclear fuel at Plant Farley. Damages are being sought for the period from January 1, 2005 through December 31, 2010. Damages will continue to accrue until the issue is resolved or storage is provided. No amounts have been recognized in the financial statements as of December 31, 2012 for any potential recoveries from the second lawsuit. The final outcome of this matter cannot be determined at this time; however, no material impact on the Company's net income is expected.

At Plant Farley, on-site dry spent fuel storage facilities are operational and can be expanded to accommodate spent fuel through the expected life of the plant.

Retail Regulatory Matters

Retail Rate Adjustments

In July 2011, the Alabama PSC issued an order to eliminate a tax-related adjustment under the Company's rate structure effective with October 2011 billings. The elimination of this adjustment resulted in additional revenues of approximately $31 million for 2011. In accordance with the order, the Company made additional accruals to the NDR in the fourth quarter 2011 of an amount equal to such additional 2011 revenues. The NDR was impacted as a result of operations and maintenance expenses incurred in connection with the April 2011 storms in Alabama. See "Natural Disaster Reserve" below for additional information. The elimination of this adjustment resulted in additional revenues of approximately $106 million for 2012.

Rate RSE

Rate stabilization and equalization plan (Rate RSE) adjustments are based on forward-looking information for the applicable upcoming calendar year. Rate adjustments for any two-year period, when averaged together, cannot exceed 4.0% and any annual adjustment is limited to 5.0%. Retail rates remain unchanged when the retail return on common equity (ROE) is projected to be between 13.0% and 14.5%. If the Company's actual retail ROE is above the allowed equity return range, customer refunds will be required; however, there is no provision for additional customer billings should the actual retail ROE fall below the allowed equity return range.

In 2011 and 2012, retail rates under Rate RSE remained unchanged from 2010. On November 30, 2012, the Company made its Rate RSE submission to the Alabama PSC of projected data for calendar year 2013; projected earnings were within the specified return range, and, therefore, retail rates under Rate RSE remained unchanged for 2013. Under the terms of Rate RSE, the maximum possible increase for 2014 is 5.00%. However, the Company is working with the Alabama PSC to develop a plan that will potentially preclude the need for a Rate RSE increase in 2014. The ultimate outcome of this matter cannot be determined at this time.

Rate CNP

The Company's retail rates, approved by the Alabama PSC, provide for adjustments to recognize the placing of new generating facilities into retail service under rate certificated new plant (Rate CNP). The Company may also recover retail costs associated with certificated PPAs under rate certificated new plant (Rate CNP PPA). Effective April 2011, Rate CNP PPA was reduced by approximately $5 million annually. On March 6, 2012, the Alabama PSC issued a consent order that the Company leave in effect the current Rate CNP PPA factor for billings for the period April 1, 2012 through March 31, 2013. It is anticipated that no adjustment will be made to Rate CNP PPA in 2013. As of December 31, 2012, the Company had an under recovered certificated PPA balance of $9 million, $7 million of which is included in deferred under recovered regulatory clause revenues and $2 million of which is included in under recovered regulatory clause revenues in the balance sheet.

On September 17, 2012, the Alabama PSC approved and certificated a PPA for the purchase of approximately 200 megawatts (MWs) of the approximately 400 MWs of energy from wind-powered generating facilities and all associated environmental attributes, including renewable energy credits. The terms of this PPA and a previously approved and certificated PPA permit the Company to use the energy and retire the associated environmental attributes in service of its customers or to sell environmental attributes, separately or bundled with energy, to third parties. Approximately 200 MWs of energy from wind-powered generating facilities was operational in December 2012.

Rate certificated new plant environmental (Rate CNP Environmental) also allows for the recovery of the Company's retail costs associated with environmental laws, regulations, or other such mandates. Rate CNP Environmental is based on forward-looking information and provides for the recovery of these costs pursuant to a factor that is calculated annually. Environmental costs to be recovered include operations and maintenance expenses, depreciation, and a return on certain invested capital. There was no adjustment to Rate CNP Environmental to recover environmental costs in 2011 or 2012. On November 26, 2012, the Company submitted calculations associated with its cost of complying with environmental mandates, as provided under Rate CNP Environmental. The filing reflected a projected unrecovered retail revenue requirement for environmental compliance of less than $1 million, which is to be recovered in the billing months of January 2013 through December 2013. On December 4, 2012, the Alabama PSC issued a consent order that the Company leave in effect for 2013 the factors associated with the Company's environmental compliance costs for the year 2012. Any unrecovered amounts associated with 2013 will be reflected in the 2014 filing. As of December 31, 2012, the Company had an under recovered environmental clause balance of $21 million which is included in under recovered regulatory clause revenues in the balance sheet.

Environmental Accounting Order

Proposed and final environmental regulations could result in significant additional compliance costs that could affect future unit retirement and replacement decisions. In September 2011, the Alabama PSC approved an order allowing for the establishment of a regulatory asset to record the unrecovered investment costs associated with any such decisions, including the unrecovered plant asset balance and the unrecovered costs associated with site removal and closure. These costs would be amortized over the affected unit's remaining useful life, as established prior to the decision regarding early retirement.

Compliance and Pension Cost Accounting Order

On November 6, 2012, the Alabama PSC approved an accounting order for certain compliance-related operation and maintenance expenditures for the years 2013 through 2017, as well as the incremental increase in operation expense related to pension cost for 2013. Under the accounting order, expenses from January 2013 through December 2017 related to compliance with standards addressing Critical Infrastructure Protection issued by the North American Electric Reliability Corporation and cyber security requirements issued by the NRC will be deferred to a regulatory asset account and amortized over a three-year period beginning in January 2015. Expenses from January 2013 through December 2017 related to compliance with NRC guidance addressing the readiness at nuclear facilities within the U.S., as prompted by the earthquake and tsunami that struck Japan in March 2011, also will be deferred as a regulatory asset and recovered over the same amortization period. The compliance-related expenses to be afforded regulatory asset treatment over the five-year period are currently estimated to be approximately $43 million. In addition, the accounting order authorizes the Company to defer an incremental increase in its pension cost for 2013. That increased pension cost is estimated to be approximately $17 million. During 2013, the actual incremental increase will be deferred to a regulatory asset account and will be amortized over a three-year period beginning in January 2015. Pursuant to the accounting order, the Company has the ability to accelerate the amortization of the regulatory assets.

Energy Cost Recovery

The Company has established energy cost recovery rates under the Company's energy cost recovery rate (Rate ECR) as approved by the Alabama PSC. Rates are based on an estimate of future energy costs and the current over or under recovered balance. Revenues recognized under Rate ECR and recorded on the financial statements are adjusted for the difference in actual recoverable fuel costs and amounts billed in current regulated rates. The difference in the recoverable fuel costs and amounts billed give rise to the over or under recovered amounts recorded as regulatory assets or liabilities. The Company, along with the Alabama PSC, continually monitors the over or under recovered cost balance to determine whether an adjustment to billing rates is required. Changes in the Rate ECR factor have no significant effect on the Company's net income, but will impact operating cash flows. Currently, the Alabama PSC may approve billing rates under Rate ECR of up to 5.910 cents per kilowatt hour (KWH). On December 4, 2012, the Alabama PSC issued a consent order that the Company leave in effect the energy cost recovery rates which began in April 2011 for 2013. Therefore, the Rate ECR factor as of January 1, 2013 remained at 2.681 cents per KWH. Effective with billings beginning in January 2014, the Rate ECR factor will be 5.910 cents per KWH, absent a further order from the Alabama PSC.

As of December 31, 2012 and 2011, the Company had under recovered fuel balances of approximately $4 million and $31 million, respectively, which are included in deferred under recovered regulatory clause revenues in the balance sheets. This classification is based on estimates, which include such factors as weather, generation availability, energy demand, and the price of energy. A change in any of these factors could have a material impact on the timing of any recovery of the under recovered fuel costs.

Natural Disaster Reserve

Based on an order from the Alabama PSC, the Company maintains a reserve for operations and maintenance expenses to cover the cost of damages from major storms to its transmission and distribution facilities. The order approves a separate monthly Rate NDR charge to customers consisting of two components. The first component is intended to establish and maintain a reserve balance for future storms and is an on-going part of customer billing. The second component of the Rate NDR charge is intended to allow recovery of any existing deferred storm-related operations and maintenance costs and any future reserve deficits over a 24-month period. The Alabama PSC order gives the Company authority to record a deficit balance in the NDR when costs of storm damage exceed any established reserve balance. Absent further Alabama PSC approval, the maximum total Rate NDR charge consisting of both components is $10 per month per non-residential customer account and $5 per month per residential customer account. The Company has the authority, based on an order from the Alabama PSC, to accrue certain additional amounts as circumstances warrant. The order allows for reliability-related expenditures to be charged against the additional accruals when the NDR balance exceeds $75 million. The Company may designate a portion of the NDR to reliability-related expenditures as a part of an annual budget process for the following year or during the current year for identified unbudgeted reliability-related expenditures that are incurred. Accruals that have not been designated can be used to offset storm charges. Additional accruals to the NDR will enhance the Company's ability to deal with the financial effects of future natural disasters, promote system reliability, and offset costs retail customers would otherwise bear.

As revenue from the Rate NDR charge is recognized, an equal amount of operations and maintenance expenses related to the NDR will also be recognized. As a result, the Rate NDR charge will not have an effect on net income but will impact operating cash flows.

During the first half of 2011, multiple storms caused varying degrees of damage to the Company's transmission and distribution facilities. The most significant storms occurred in April 2011, causing over 400,000 of the Company's 1.4 million customers to be without electrical service. The cost of repairing the damage to facilities and restoring electrical service to customers as a result of these storms was $42 million for operations and maintenance expenses and $161 million for capital-related expenditures.

In accordance with the order that was issued by the Alabama PSC in July 2011 to eliminate a tax-related adjustment under the Company's rate structure that resulted in additional revenues, the Company made additional accruals to the NDR in the fourth quarter 2011 of an amount equal to the additional 2011 revenues, which were approximately $31 million.

The accumulated balances in the NDR for the years ended December 31, 2012 and December 31, 2011 were approximately $103 million and $110 million, respectively. Any accruals to the NDR are included in the balance sheets under other regulatory liabilities, deferred and are reflected as other operations and maintenance expenses in the statements of income.

Nuclear Outage Accounting Order

In 2010, the Alabama PSC approved a change to the nuclear maintenance outage accounting process associated with routine refueling activities. Previously, the Company accrued nuclear outage operations and maintenance expenses for the two units at Plant Farley during the 18-month cycle for the outages. In accordance with the 2010 order, nuclear outage expenses are deferred when the charges actually occur and then amortized over the subsequent 18-month period.

The initial result of implementation of the accounting order was that no nuclear maintenance outage expenses were recognized from January 2011 through December 2011, which decreased nuclear outage operations and maintenance expenses in 2011 from 2010 by approximately $50 million. During the fall of 2011, approximately $38 million of actual nuclear outage expenses associated with one unit at Plant Farley was deferred to a regulatory asset account; beginning in January 2012, these deferred costs are being amortized to nuclear operations and maintenance expenses over an 18-month period. During the spring of 2012, approximately $31 million of actual nuclear outage expenses associated with the second unit at Plant Farley was deferred to a regulatory asset account; beginning in July 2012, these deferred costs are being amortized to nuclear operations and maintenance expenses over an 18-month period. The Company will continue the pattern of deferral of nuclear outage expenses as incurred and the recognition of expenses over a subsequent 18-month period pursuant to the existing order.

4. JOINT OWNERSHIP AGREEMENTS

The Company and Georgia Power own equally all of the outstanding capital stock of SEGCO, which owns electric generating units with a total rated capacity of 1,020 MWs, as well as associated transmission facilities. The capacity of these units is sold equally to the Company and Georgia Power under a power contract. The Company and Georgia Power make payments sufficient to provide for the operating expenses, taxes, interest expense, and a return on equity. The Company's share of purchased power totaled $109 million in 2012, $142 million in 2011, and $101 million in 2010, and is included in "Purchased power from affiliates" in the statements of income. The Company accounts for SEGCO using the equity method.

In addition, the Company has guaranteed unconditionally the obligation of SEGCO under an installment sale agreement for the purchase of certain pollution control facilities at SEGCO's generating units, pursuant to which $25 million principal amount of pollution control revenue bonds are outstanding. Also, the Company has guaranteed $50 million principal amount of unsecured senior notes issued by SEGCO for general corporate purposes. These senior notes mature on May 15, 2013. Georgia Power has agreed to reimburse the Company for the pro rata portion of such obligations corresponding to its then proportionate ownership of stock of SEGCO if the Company is called upon to make such payment under its guaranty.

At December 31, 2012, the capitalization of SEGCO consisted of $82 million of equity and $75 million of long-term debt on which the annual interest requirement is $3 million. In addition, SEGCO had short-term debt outstanding of $45 million. SEGCO paid dividends of $14 million in 2012, $15 million in 2011, and $5 million in 2010, of which one-half of each was paid to the Company. In addition, the Company recognizes 50% of SEGCO's net income.

SEGCO plans to add natural gas as the primary fuel source in 2015 for 1,000 MWs of its generating capacity. It is currently planning and developing the necessary natural gas pipeline. The Company, which owns and operates a generating unit adjacent to the SEGCO generating units, has entered into a joint ownership agreement with SEGCO for the ownership of the gas pipeline. The Company will own 14% of the pipeline with the remaining 86% owned by SEGCO. At December 31, 2012, the Company's portion of the construction work in progress associated with the construction of the pipeline is $0.1 million.

In addition to the Company's ownership of SEGCO and joint ownership of the natural gas pipeline, the Company's percentage ownership and investment in jointly-owned coal-fired generating plants at December 31, 2012 were as follows:

Facility	Total Megawatt Capacity	Company Ownership	Plant in Service	Accumulated Depreciation	Construction Work in Progress
			(in millions)		
Greene County	500	60.00% (1)	$ 151	$ 89	$ 9
Plant Miller Units 1 and 2	1,320	91.84% (2)	1,401	551	8

(1) Jointly owned with an affiliate, Mississippi Power.
(2) Jointly owned with PowerSouth.

The Company has contracted to operate and maintain the jointly-owned facilities as agent for their co-owners. The Company's proportionate share of its plant operating expenses is included in operating expenses in the statements of income and the Company is responsible for providing its own financing.

5. INCOME TAXES

On behalf of the Company, Southern Company files a consolidated federal income tax return and combined state income tax returns for the States of Alabama, Georgia, and Mississippi. In addition, the Company files a separate company income tax return for the State of Tennessee. Under a joint consolidated income tax allocation agreement, each subsidiary's current and deferred tax expense is computed on a stand-alone basis and no subsidiary is allocated more current expense than would be paid if it filed a separate income tax return. In accordance with IRS regulations, each company is jointly and severally liable for the federal tax liability.

Current and Deferred Income Taxes

Details of income tax provisions are as follows:

	2012	2011	2010
		(in millions)	
Federal —			
Current	**$ 262**	$ 20	$ 52
Deferred	**137**	377	333
	399	397	385
State —			
Current	**51**	(1)	1
Deferred	**27**	82	77
	78	81	78
Total	**$ 477**	$ 478	$ 463

The tax effects of temporary differences between the carrying amounts of assets and liabilities in the financial statements and their respective tax bases, which give rise to deferred tax assets and liabilities, are as follows:

	2012	2011
	(in millions)	
Deferred tax liabilities —		
Accelerated depreciation	**$ 2,989**	$ 2,820
Property basis differences	**420**	439
Premium on reacquired debt	**36**	33
Employee benefit obligations	**218**	217
Under recovered energy clause	**16**	26
Regulatory assets associated with employee benefit obligations	**378**	343
Regulatory assets associated with asset retirement obligations	**248**	233
Other	**114**	94
Total	**4,419**	4,205
Deferred tax assets —		
Federal effect of state deferred taxes	**194**	186
State effect of federal deferred taxes	**—**	—
Unbilled fuel revenue	**39**	38
Storm reserve	**34**	38
Employee benefit obligations	**408**	373
Other comprehensive losses	**19**	14
Asset retirement obligations	**248**	233
Other	**98**	97
Total	**1,040**	979
Total deferred tax liabilities, net	**3,379**	3,226
Portion included in current assets (liabilities), net	**25**	31
Accumulated deferred income taxes	**$ 3,404**	$ 3,257

At December 31, 2012, the Company's tax-related regulatory assets to be recovered from customers were $525 million. These assets are primarily attributable to tax benefits that flowed through to customers in prior years, to deferred taxes previously recognized at rates lower than the current enacted tax law, and to taxes applicable to capitalized interest.

At December 31, 2012, the Company's tax-related regulatory liabilities to be credited to customers were $79 million. These liabilities are primarily attributable to unamortized investment tax credits.

In accordance with regulatory requirements, deferred investment tax credits are amortized over the life of the related property with such amortization normally applied as a credit to reduce depreciation in the statements of income. Credits amortized in this manner amounted to $8 million in each of 2012, 2011, and 2010. At December 31, 2012, all investment tax credits available to reduce federal income taxes payable had been utilized.

In 2010, the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010 (Tax Relief Act) was signed into law. Major tax incentives in the Tax Relief Act include 100% bonus depreciation for property placed in service after September 8, 2010 and through 2011 (and for certain long-term production-period projects placed in service in 2012) and 50% bonus depreciation for property placed in service in 2012 (and for certain long-term production-period projects to be placed in service in 2013). The application of the bonus depreciation provisions in the Tax Relief Act significantly increased deferred tax liabilities related to accelerated depreciation.

Effective Tax Rate

A reconciliation of the federal statutory income tax rate to the effective income tax rate is as follows:

	2012	2011	2010
Federal statutory rate	**35.0%**	35.0%	35.0%
State income tax, net of federal deduction	**4.1**	4.3	4.2
Non-deductible book depreciation	**0.9**	0.8	0.8
Differences in prior years' deferred and current tax rates	**(0.1)**	(0.1)	(0.1)
AFUDC equity	**(0.5)**	(0.6)	(1.0)
Other	**(0.3)**	(0.4)	(0.6)
Effective income tax rate	**39.1%**	39.0%	38.3%

The increase in the Company's 2012 effective tax rate was not material.

The increase in the Company's 2011 effective tax rate was due to a decrease in the tax benefit of AFUDC equity due to a decrease in AFUDC, resulting from the completion of construction projects related to environmental mandates at generating facilities. See Note 1 under "Allowance for Funds Used During Construction" for additional information.

Unrecognized Tax Benefits

For 2012, the total amount of unrecognized tax benefits decreased by $1 million, resulting in a balance of $31 million as of December 31, 2012.

Changes during the year in unrecognized tax benefits were as follows:

	2012	2011	2010
		(in millions)	
Unrecognized tax benefits at beginning of year	**$ 32**	$ 43	$ 6
Tax positions from current periods	**5**	6	6
Tax positions from prior periods	**(4)**	(17)	31
Reductions due to settlements	**(2)**	—	—
Balance at end of year	**$ 31**	$ 32	$ 43

The tax positions from current periods for 2012 relate primarily to the tax accounting method change for repairs-generation assets. See "Tax Method of Accounting for Repairs" herein for additional information. The American Jobs Creation Act of 2004 created a tax deduction for a portion of income attributable to U.S. production activities as defined in Section 199 of the Internal Revenue Code (production activities deduction). The tax positions decrease from prior periods and the reductions due to settlements for 2012 relate to a settlement with the IRS of the calculation methodology for the production activities deduction.

The impact on the Company's effective tax rate, if recognized, was as follows:

	2012	2011	2010
		(in millions)	
Tax positions impacting the effective tax rate	$ —	$ 5	$ 6
Tax positions not impacting the effective tax rate	31	27	37
Balance of unrecognized tax benefits	$ 31	$ 32	$ 43

The tax positions not impacting the effective tax rate for 2012 relate to the timing difference associated with the tax accounting method change for repairs-generation assets. See "Tax Method of Accounting for Repairs" herein for additional information. These amounts are presented on a gross basis without considering the related federal or state income tax impact.

Accrued interest for unrecognized tax benefits was as follows:

	2012	2011	2010
		(in millions)	
Interest accrued at beginning of year	$ 1.9	$ 1.5	$ 0.3
Interest reclassified due to settlements	(1.9)	—	—
Interest accrued during the year	—	0.4	1.2
Balance at end of year	$ —	$ 1.9	$ 1.5

The Company classifies interest on tax uncertainties as interest expense. The Company did not accrue any penalties on uncertain tax positions.

It is reasonably possible that the amount of the unrecognized tax benefits associated with a majority of the Company's unrecognized tax positions will significantly increase or decrease within 12 months. The resolution of the tax accounting method change for repairs-generation assets, as well as the conclusion or settlement of state audits, could impact the balances significantly. At this time, an estimate of the range of reasonably possible outcomes cannot be determined.

The IRS has audited and closed all of Southern Company's consolidated federal income tax returns prior to 2009 and has settled its audits of Southern Company's consolidated federal income tax returns for 2009 and 2010, in principle, pending final approval. Additionally, the IRS has audited and closed Southern Company's 2011 consolidated federal income tax return. For tax years 2010 through 2013, Southern Company is a participant in the Compliance Assurance Process of the IRS. The audits for the Company's state income tax returns have either been concluded, or the statute of limitations has expired, for years prior to 2007.

Tax Method of Accounting for Repairs

Southern Company submitted a tax accounting method change related to the deductibility of repair costs associated with its subsidiaries' generation, transmission, and distribution systems effective for the 2009 consolidated federal income tax return in 2010. In August 2011, the IRS issued a revenue procedure, which provides a safe harbor method of accounting that taxpayers may use to determine eligible repair costs for transmission and distribution property. The IRS continues to work with the utility industry in an effort to define eligible repair costs for generation assets in a consistent manner for all utilities. The IRS published regulations on the deduction and capitalization of expenditures related to tangible property that generally apply for tax years beginning on or after January 1, 2014. The utility industry anticipates more detailed guidance concerning these regulations. Due to the uncertainty regarding the ultimate resolution of the repair costs for generation assets, an unrecognized tax position has been recorded for the tax accounting method change for repairs-generation assets. The ultimate outcome of this matter cannot be determined at this time; however, it is not expected to materially impact net income.

6. FINANCING

Long-Term Debt Payable to an Affiliated Trust

The Company has formed a wholly-owned trust subsidiary for the purpose of issuing preferred securities. The proceeds of the related equity investments and preferred security sales were loaned back to the Company through the issuance of junior subordinated notes totaling $206 million as of December 31, 2012 and December 31, 2011, which constitute substantially all of the assets of this trust and are reflected in the balance sheets as long-term debt payable. The Company considers that the mechanisms and obligations relating to the preferred securities issued for its benefit, taken together, constitute a full and unconditional guarantee by it of the trust's payment obligations with respect to these securities. At December 31, 2012 and 2011, trust preferred securities of $200 million were outstanding. See Note 1 under "Variable Interest Entities" for additional information on the accounting treatment for this trust and the related securities.

Securities Due Within One Year

At December 31, 2012 and 2011, the Company had scheduled maturities of senior notes due within one year totaling $250 million and $500 million, respectively.

Maturities of senior notes and pollution control revenue bonds through 2017 applicable to total long-term debt are as follows: $250 million in 2013; $454 million in 2015; $200 million in 2016; and $561 million in 2017. There are no scheduled maturities in 2014.

Pollution Control Revenue Bonds

Pollution control obligations represent loans to the Company from public authorities of funds or installment purchases of pollution control and solid waste disposal facilities financed by funds derived from sales by public authorities of revenue bonds. The Company is required to make payments sufficient for the authorities to meet principal and interest requirements of such bonds. The Company incurred no obligations related to the issuance of pollution control revenue bonds in 2012. In 2012, the Company redeemed approximately $0.7 million of The Industrial Development Board of the Town of West Jefferson Solid Waste Disposal Revenue Bonds (Alabama Power Company Miller Plant Project), Series 2008. The amount of tax-exempt pollution control revenue bonds outstanding at both December 31, 2012 and 2011 was $1.2 billion. Proceeds from certain issuances are restricted until qualifying expenditures are incurred.

Senior Notes

The Company issued a total of $1.0 billion of unsecured senior notes in 2012. The proceeds of these issuances were used for general corporate purposes, including the Company's continuous construction program, to redeem $450 million of unsecured senior notes in 2012, and to pay at maturity $500 million of unsecured senior notes in 2012.

At both December 31, 2012 and 2011, the Company had $4.8 billion of senior notes outstanding. These senior notes are effectively subordinated to all secured debt of the Company which amounted to approximately $153 million at December 31, 2012.

Preferred, Preference, and Common Stock

In 2012, the Company issued no new shares of preferred stock, preference stock, or common stock.

Outstanding Classes of Capital Stock

The Company currently has preferred stock, Class A preferred stock, preference stock, and common stock authorized and outstanding. The Company's preferred stock and Class A preferred stock, without preference between classes, rank senior to the Company's preference stock and common stock with respect to payment of dividends and voluntary and involuntary dissolution. The preferred stock and Class A preferred stock of the Company contain a feature that allows the holders to elect a majority of the Company's board of directors if dividends are not paid for four consecutive quarters. Because such a potential redemption-triggering event is not solely within the control of the Company, the preferred stock and Class A preferred stock is presented as "Redeemable Preferred Stock" in a manner consistent with temporary equity under applicable accounting standards. The preference stock does not contain such a provision that would allow the holders to elect a majority of the Company's board. The Company's preference stock ranks senior to the common stock with respect to the payment of dividends and voluntary or involuntary dissolution.

The Company's preferred stock is subject to redemption at a price equal to the par value plus a premium. The Company's Class A preferred stock is subject to redemption at a price equal to the stated capital. Certain series of the Company's preference stock are subject to redemption at a price equal to the stated capital plus a make-whole premium based on the present value of the liquidation amount and future dividends to the first stated capital redemption date and the other series of preference stock are subject to redemption at a price equal to the stated capital. Certain series of the Company's preferred stock are subject to redemption at the option of the Company on or after a specified date. Information for each outstanding series is in the table below:

Preferred/Preference Stock	Par Value/ Stated Capital Per Share	Shares Outstanding	First Call Date	Redemption Price Per Share
4.92% Preferred Stock	$100	80,000	*	$103.23
4.72% Preferred Stock	$100	50,000	*	$102.18
4.64% Preferred Stock	$100	60,000	*	$103.14
4.60% Preferred Stock	$100	100,000	*	$104.20
4.52% Preferred Stock	$100	50,000	*	$102.93
4.20% Preferred Stock	$100	135,115	*	$105.00
5.83% Class A Preferred Stock	$25	1,520,000	8/1/2008	Stated Capital
5.20% Class A Preferred Stock	$25	6,480,000	8/1/2008	Stated Capital
5.30% Class A Preferred Stock	$25	4,000,000	4/1/2009	Stated Capital
5.625% Preference Stock	$25	6,000,000	1/1/2012	Stated Capital
6.450% Preference Stock	$25	6,000,000	*	**
6.500% Preference Stock	$25	2,000,000	*	**

* Redemption permitted any time after issuance

** Prior to 10/01/2017: Stated Value Plus Make-Whole Premium; after 10/01/2017: Stated Capital

Dividend Restrictions

The Company can only pay dividends to Southern Company out of retained earnings or paid-in-capital.

Assets Subject to Lien

The Company has granted liens on certain property in connection with the issuance of certain series of pollution control revenue bonds with an outstanding principal amount of $153 million as of December 31, 2012. There are no agreements or other arrangements among the Southern Company system companies under which the assets of one company have been pledged or otherwise made available to satisfy obligations of Southern Company or any of its other subsidiaries.

Bank Credit Arrangements

At December 31, 2012, committed credit arrangements with banks were as follows:

Expires[a]					Executable Term-Loans		Due Within One Year	
2013	2014	2016	Total	Unused	One Year	Two Years	Term Out	No Term Out
			(in millions)					
$ 158	$ 350	$ 800	$ 1,308	$ 1,308	$ 56	$ —	$ 56	$ 102

(a) No credit arrangements expire in 2015.

The Company expects to renew its credit agreements as needed, prior to expiration. Most of the credit arrangements require payment of a commitment fee based on the unused portion of the commitments or the maintenance of compensating balances with the banks. Commitment fees average less than 1/4 of 1% for the Company. Compensating balances are not legally restricted from withdrawal.

Most of the Company's credit arrangements with banks have covenants that limit the Company's debt to 65% of total capitalization, as defined in the arrangements. For purposes of calculating these covenants, long-term notes payable to affiliated trusts are excluded from debt but included in capitalization. Exceeding this debt level would result in a default under the credit arrangements. At December 31, 2012, the Company was in compliance with the debt limit covenants.

In addition, the credit arrangements typically contain cross default provisions that are restricted to indebtedness (including guaranteed obligations) of the Company. The Company is currently in compliance with all such covenants. None of the arrangements contain material adverse change clauses at the time of borrowings.

A portion of the unused credit with banks is allocated to provide liquidity support to the Company's variable rate pollution control revenue bonds and commercial paper program. During 2012, the Company remarketed $207 million of pollution control revenue bonds. The amount of variable rate pollution control revenue bonds requiring liquidity support was $793 million as of December 31, 2012.

The Company borrows through commercial paper programs that have the liquidity support of committed bank credit arrangements. The Company may also make short-term borrowings through various other arrangements with banks. At December 31, 2012 and 2011, there was no short-term debt outstanding. At December 31, 2012, the Company had regulatory approval to have outstanding up to $2.3 billion of short-term borrowings.

7. COMMITMENTS

Fuel and Purchased Power Agreements

To supply a portion of the fuel requirements of its generating plants, the Company has entered into various long-term commitments for the procurement of fossil and nuclear fuel which are not recognized on the balance sheets. In 2012, 2011, and 2010, the Company incurred fuel expense of $1.5 billion, $1.7 billion, and $1.9 billion, respectively, the majority of which was purchased under long-term commitments. The Company expects that a substantial amount of its future fuel needs will continue to be purchased under long-term commitments.

In addition, the Company has entered into various long-term commitments for the purchase of capacity and electricity, some of which are accounted for as operating leases. Total expense under PPAs accounted for as operating leases was $33 million, $33 million, and $30 million for 2012, 2011, and 2010, respectively. Total estimated minimum long-term obligations at December 31, 2012 were as follows:

	Commitments
	Non-Affiliated
	(in millions)
2013	$ 31
2014	37
2015	38
2016	39
2017	40
2018 and thereafter	223
Total commitments	$ 408

Certain PPAs reflected in the table are accounted for as operating leases.

SCS may enter into various types of wholesale energy and natural gas contracts acting as an agent for the Company and all of the other Southern Company traditional operating companies and Southern Power. Under these agreements, each of the traditional operating companies and Southern Power may be jointly and severally liable. The credit rating of Southern Power is currently below that of the traditional operating companies. Accordingly, Southern Company has entered into keep-well agreements with the Company and each of the other traditional operating companies to ensure the Company will not subsidize or be responsible for any costs, losses, liabilities, or damages resulting from the inclusion of Southern Power as a contracting party under these agreements.

Operating Leases

The Company has entered into rental agreements for coal railcars, vehicles, and other equipment with various terms and expiration dates. Total rent expense was $24 million in 2012, $23 million in 2011, and $25 million in 2010. Of these amounts, $19 million, $18 million, and $20 million for 2012, 2011, and 2010, respectively, relate to the railcar leases and are recoverable through the Company's Rate ECR. As of December 31, 2012, estimated minimum lease payments under operating leases were as follows:

	Minimum Lease Payments		
	Railcars	Vehicles & Other	Total
	(in millions)		
2013	$ 16	$ 4	$ 20
2014	10	2	12
2015	8	—	8
2016	8	1	9
2017	4	—	4
2018 and thereafter	9	—	9
Total	$ 55	$ 7	$ 62

In addition to the above rental commitments payments, the Company has potential obligations upon expiration of certain leases with respect to the residual value of the leased property. These leases have terms expiring through 2018 with maximum obligations under these leases of $21 million in 2013, $8 million in 2014, $5 million in 2015, $4 million in 2016, none in 2017, and $12 million in 2018 and thereafter. At the termination of the leases, the lessee may either exercise its purchase option, or the property can be sold to a third party. The Company expects that the fair market value of the leased property would substantially reduce or eliminate the Company's payments under the residual value obligations.

Guarantees

At December 31, 2012, the Company had outstanding guarantees related to SEGCO's purchase of certain pollution control facilities and issuance of senior notes, as discussed in Note 4, and to certain residual values of leased assets as described above in "Operating Leases."

8. STOCK COMPENSATION

Stock Options

Southern Company provides non-qualified stock options through its Omnibus Incentive Compensation Plan to a large segment of the Company's employees ranging from line management to executives. As of December 31, 2012, there were 1,057 current and former employees of the Company participating in the stock option program, and there were 39 million shares of Southern Company common stock remaining available for awards under the Omnibus Incentive Compensation Plan. The prices of options were at the fair market value of the shares on the dates of grant. These options become exercisable pro rata over a maximum period of three years from the date of grant. The Company generally recognizes stock option expense on a straight-line basis over the vesting period which equates to the requisite service period; however, for employees who are eligible for retirement, the total cost is expensed at the grant date. Options outstanding will expire no later than 10 years after the date of grant, unless terminated earlier by the Southern Company Board of Directors in accordance with the Omnibus Incentive Compensation Plan. For certain stock option awards, a change in control will provide accelerated vesting.

The estimated fair values of stock options granted were derived using the Black-Scholes stock option pricing model. Expected volatility was based on historical volatility of Southern Company's stock over a period equal to the expected term. Southern Company used historical exercise data to estimate the expected term that represents the period of time that options granted to employees are expected to be outstanding. The risk-free rate was based on the U.S. Treasury yield curve in effect at the time of grant that covers the expected term of the stock options.

The following table shows the assumptions used in the pricing model and the weighted average grant-date fair value of stock options granted:

Year Ended December 31	2012	2011	2010
Expected volatility	**17.7%**	17.5%	17.4%
Expected term *(in years)*	**5.0**	5.0	5.0
Interest rate	**0.9%**	2.3%	2.4%
Dividend yield	**4.2%**	4.8%	5.6%
Weighted average grant-date fair value	**$ 3.39**	$ 3.23	$ 2.23

The Company's activity in the stock option program for 2012 is summarized below:

	Shares Subject to Option	Weighted Average Exercise Price
Outstanding at December 31, 2011	7,191,786	$ 33.63
Granted	1,099,315	44.44
Exercised	(2,226,269)	32.43
Cancelled	(4,280)	38.74
Outstanding at December 31, 2012	**6,060,552**	**$ 36.02**
Exercisable at December 31, 2012	**3,884,089**	**$ 33.84**

The number of stock options vested, and expected to vest in the future, as of December 31, 2012 was not significantly different from the number of stock options outstanding at December 31, 2012 as stated above. As of December 31, 2012, the weighted average remaining contractual term for the options outstanding and options exercisable was approximately six years and five years, respectively, and the aggregate intrinsic value for the options outstanding and options exercisable was $43 million and $35 million, respectively.

As of December 31, 2012, there was $1 million of total unrecognized compensation cost related to stock option awards not yet vested. That cost is expected to be recognized over a weighted-average period of approximately 11 months.

For the years ended December 31, 2012, 2011, and 2010, total compensation cost for stock option awards recognized in income was $4 million, $3 million, and $3 million, respectively, with the related tax benefit also recognized in income of $1 million, $1 million, and $1 million, respectively.

The compensation cost and tax benefits related to the grant and exercise of Southern Company stock options to the Company's employees are recognized in the Company's financial statements with a corresponding credit to equity, representing a capital contribution from Southern Company.

The total intrinsic value of options exercised during the years ended December 31, 2012, 2011, and 2010 was $28 million, $23 million, and $12 million, respectively. The actual tax benefit realized by the Company for the tax deductions from stock option exercises totaled $11 million, $9 million, and $4 million for the years ended December 31, 2012, 2011, and 2010, respectively.

Performance Shares

Southern Company provides performance share award units through its Omnibus Incentive Compensation Plan to a large segment of the Company's employees ranging from line management to executives. The performance share units granted under the plan vest at the end of a three-year performance period which equates to the requisite service period. Employees that retire prior to the end of the three-year period receive a pro rata number of shares, issued at the end of the performance period, based on actual months of service prior to retirement. The value of the award units is based on Southern Company's total shareholder return (TSR) over the three-year performance period which measures Southern Company's relative performance against a group of industry peers. The performance shares are delivered in common stock following the end of the performance period based on Southern Company's actual TSR and may range from 0% to 200% of the original target performance share amount.

The fair value of performance share awards is determined as of the grant date using a Monte Carlo simulation model to estimate the TSR of Southern Company's stock among the industry peers over the performance period. The Company recognizes compensation expense on a straight-line basis over the three-year performance period without remeasurement. Compensation expense for awards where the service condition is met is recognized regardless of the actual number of shares issued. The expected volatility was based on the historical volatility of Southern Company's stock over a period equal to the performance period. The risk-free rate was based on the U.S. Treasury yield curve in effect at the time of grant that covers the performance period of the award units.

The following table shows the assumptions used in the pricing model and the weighted average grant-date fair value of performance share award units granted:

Year Ended December 31	2012	2011	2010
Expected volatility	**16.0%**	19.2%	20.7%
Expected term *(in years)*	**3.0**	3.0	3.0
Interest rate	**0.4%**	1.4%	1.4%
Annualized dividend rate	**$1.89**	$1.82	$1.75
Weighted average grant-date fair value	**$41.99**	$35.97	$30.13

Total unvested performance share units outstanding as of December 31, 2011 were 287,720. During 2012, 131,820 performance share units were granted, 134,054 performance share units were vested, and 4,950 performance share units were forfeited resulting in 280,536 unvested units outstanding at December 31, 2012. In January 2013, the vested performance share award units were converted into 180,997 shares outstanding at a share price of $43.05 for the three-year performance and vesting period ended December 31, 2012.

For the years ended December 31, 2012, 2011, and 2010, total compensation cost for performance share units recognized in income was $5 million, $3 million, and $1 million, respectively, with the related tax benefit also recognized in income of $2 million, $1 million, and $1 million, respectively. As of December 31, 2012, there was $5 million of total unrecognized compensation cost related to performance share award units that will be recognized over a weighted-average period of approximately 11 months.

9. NUCLEAR INSURANCE

Under the Price-Anderson Amendments Act (Act), the Company maintains agreements of indemnity with the NRC that, together with private insurance, cover third-party liability arising from any nuclear incident occurring at Plant Farley. The Act provides funds up to $12.6 billion for public liability claims that could arise from a single nuclear incident. Plant Farley is insured against this liability to a maximum of $375 million by American Nuclear Insurers (ANI), with the remaining coverage provided by a mandatory program of deferred premiums that could be assessed, after a nuclear incident, against all owners of commercial nuclear reactors. The Company could be assessed up to $117.5 million per incident for each licensed reactor it operates but not more than an aggregate of $17.5 million per incident to be paid in a calendar year for each reactor. Such maximum assessment, excluding any applicable state premium taxes, for the Company is $235 million per incident but not more than an aggregate of $35 million to be paid for each incident in any one year. Both the maximum assessment per reactor and the maximum yearly assessment are adjusted for inflation at least every five years. The next scheduled adjustment is due no later than October 29, 2013.

The Company is a member of Nuclear Electric Insurance Limited (NEIL), a mutual insurer established to provide property damage insurance in an amount up to $500 million for members' operating nuclear generating facilities. Additionally, the Company has policies that currently provide decontamination, excess property insurance, and premature decommissioning coverage up to $2.25 billion for losses in excess of the $500 million primary coverage. This excess insurance is also provided by NEIL.

NEIL also covers the additional costs that would be incurred in obtaining replacement power during a prolonged accidental outage at a member's nuclear plant. Members can purchase this coverage, subject to a deductible waiting period of up to 26 weeks, with a maximum per occurrence per unit limit of $490 million. After the deductible period, weekly indemnity payments would be received until either the unit is operational or until the limit is exhausted in approximately three years. The Company purchases the maximum limit allowed by NEIL and has elected a 12-week deductible waiting period.

Under each of the NEIL policies, members are subject to assessments if losses each year exceed the accumulated funds available to the insurer under that policy. The current maximum annual assessments for the Company under the NEIL policies would be $42 million.

Claims resulting from terrorist acts are covered under both the ANI and NEIL policies (subject to normal policy limits). The aggregate, however, that NEIL will pay for all claims resulting from terrorist acts in any 12-month period is $3.2 billion plus such additional amounts NEIL can recover through reinsurance, indemnity, or other sources.

For all on-site property damage insurance policies for commercial nuclear power plants, the NRC requires that the proceeds of such policies shall be dedicated first for the sole purpose of placing the reactor in a safe and stable condition after an accident. Any remaining proceeds are to be applied next toward the costs of decontamination and debris removal operations ordered by the NRC, and any further remaining proceeds are to be paid either to the Company or to its debt trustees as may be appropriate under the policies and applicable trust indentures. In the event of a loss, the amount of insurance available might not be adequate to cover property damage and other expenses incurred. Uninsured losses and other expenses, to the extent not recovered from customers, would be borne by the Company and could have a material effect on the Company's financial condition and results of operations.

All retrospective assessments, whether generated for liability, property, or replacement power, may be subject to applicable state premium taxes.

10. FAIR VALUE MEASUREMENTS

Fair value measurements are based on inputs of observable and unobservable market data that a market participant would use in pricing the asset or liability. The use of observable inputs is maximized where available and the use of unobservable inputs is minimized for fair value measurement and reflects a three-tier fair value hierarchy that prioritizes inputs to valuation techniques used for fair value measurement.

- Level 1 consists of observable market data in an active market for identical assets or liabilities.
- Level 2 consists of observable market data, other than that included in Level 1, that is either directly or indirectly observable.
- Level 3 consists of unobservable market data. The input may reflect the assumptions of the Company of what a market participant would use in pricing an asset or liability. If there is little available market data, then the Company's own assumptions are the best available information.

In the case of multiple inputs being used in a fair value measurement, the lowest level input that is significant to the fair value measurement represents the level in the fair value hierarchy in which the fair value measurement is reported.

As of December 31, 2012, assets and liabilities measured at fair value on a recurring basis during the period, together with the level of the fair value hierarchy in which they fall, were as follows:

	Fair Value Measurements Using			
As of December 31, 2012:	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Total**
		(in millions)		
Assets:				
Energy-related derivatives	$ —	$ 5	$ —	$ 5
Nuclear decommissioning trusts:[a]				
Domestic equity	291	64	—	355
Foreign equity	28	55	—	83
U.S. Treasury and government agency securities	—	29	—	29
Corporate bonds	—	101	—	101
Mortgage and asset backed securities	—	26	—	26
Other investments	—	10	—	10
Total	$ 319	$ 290	$ —	$ 609
Liabilities:				
Energy-related derivatives	$ —	$ 18	$ —	$ 18

(a) Excludes receivables related to investment income, pending investment sales, and payables related to pending investment purchases.

As of December 31, 2011, assets and liabilities measured at fair value on a recurring basis during the period, together with the level of the fair value hierarchy in which they fall, were as follows:

	Fair Value Measurements Using			
As of December 31, 2011:	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
		(in millions)		
Assets:				
Nuclear decommissioning trusts:[a]				
Domestic equity	$ 253	$ 57	$ —	$ 310
Foreign equity	24	48	—	72
U.S. Treasury and government agency securities	17	8	—	25
Corporate bonds	—	93	—	93
Mortgage and asset backed securities	—	28	—	28
Other investments	—	11	—	11
Cash equivalents and restricted cash	209	—	—	209
Total	$ 503	$ 245	$ —	$ 748
Liabilities:				
Energy-related derivatives	$ —	$ 48	$ —	$ 48
Interest rate derivatives	—	18	—	18
Total	$ —	$ 66	$ —	$ 66

(a) Excludes receivables related to investment income, pending investment sales, and payables related to pending investment purchases.

Valuation Methodologies

The energy-related derivatives primarily consist of over-the-counter financial products for natural gas and physical power products including, from time to time, basis swaps. These are standard products used within the energy industry and are valued using the market approach. The inputs used are mainly from observable market sources, such as forward natural gas prices, power prices, implied volatility, and London Interbank Offered Rate (LIBOR) interest rates. Interest rate derivatives are also standard over-the-counter financial products valued using the market approach. Inputs for interest rate derivatives include LIBOR interest rates, interest rate futures contracts, and occasionally implied volatility of interest rate options. See Note 11 for additional information on how these derivatives are used.

For fair value measurements of investments within the nuclear decommissioning trusts, specifically the fixed income assets using significant other observable inputs and unobservable inputs, the primary valuation technique used is the market approach. External pricing vendors are designated for each of the asset classes in the nuclear decommissioning trusts with each security discriminately assigned a primary pricing source, based on similar characteristics.

A market price secured from the primary source vendor is then evaluated by management in its valuation of the assets within the trusts. As a general approach, market pricing vendors gather market data (including indices and market research reports) and integrate relative credit information, observed market movements, and sector news into proprietary pricing models, pricing systems, and mathematical tools. Dealer quotes and other market information including live trading levels and pricing analysts' judgment are also obtained when available.

As of December 31, 2012 and 2011, the fair value measurements of investments calculated at net asset value per share (or its equivalent), as well as the nature and risks of those investments, were as follows:

	Fair Value	Unfunded Commitments	Redemption Frequency	Redemption Notice Period
As of December 31, 2012:	*(in millions)*			
Nuclear decommissioning trusts:				
Equity-commingled funds	$55	None	Daily/Monthly	Daily/7 days
Trust-owned life insurance	96	None	Daily	15 days
As of December 31, 2011:				
Nuclear decommissioning trusts:				
Equity-commingled funds	$48	None	Daily/Monthly	Daily/7 days
Trust-owned life insurance	87	None	Daily	15 days
Cash equivalents and restricted cash:				
Money market funds	209	None	Daily	Not applicable

The nuclear decommissioning trust includes investments in TOLI. The taxable nuclear decommissioning trust invests in the TOLI in order to minimize the impact of taxes on the portfolio and can draw on the value of the TOLI through death proceeds, loans against the cash surrender value, and/or the cash surrender value, subject to legal restrictions. The amounts reported in the table above reflect the fair value of investments the insurer has made in relation to the TOLI agreements. The nuclear decommissioning trust does not own the underlying investments, but the fair value of the investments approximates the cash surrender value of the TOLI policies. The investments made by the insurer are in commingled funds. The commingled funds primarily include investments in domestic and international equity securities and predominantly high-quality fixed income securities. These fixed income securities may include U.S. Treasury and government agency fixed income securities, non-U.S. government and agency fixed income securities, domestic and foreign corporate fixed income securities, and, to some degree, mortgage and asset backed securities. The passively managed funds seek to replicate the performance of a related index. The actively managed funds seek to exceed the performance of a related index through security analysis and selection.

The money market funds are short-term investments of excess funds in various money market mutual funds, which are portfolios of short-term debt securities. The money market funds are regulated by the SEC and typically receive the highest rating from credit rating agencies. Regulatory and rating agency requirements for money market funds include minimum credit ratings and maximum maturities for individual securities and a maximum weighted average portfolio maturity. Redemptions are available on a same day basis, up to the full amount of the Company's investment in the money market funds.

As of December 31, 2012 and 2011, other financial instruments for which the carrying amount did not equal fair value were as follows:

	Carrying Amount	Fair Value
	(in millions)	
Long-term debt:		
2012	**$6,179**	**$6,899**
2011	$6,132	$6,874

The fair values are determined using Level 2 measurements and are based on quoted market prices for the same or similar issues or on the current rates offered to the Company.

11. DERIVATIVES

The Company is exposed to market risks, primarily commodity price risk and interest rate risk. To manage the volatility attributable to these exposures, the Company nets its exposures, where possible, to take advantage of natural offsets and enters into various derivative transactions for the remaining exposures pursuant to the Company's policies in areas such as counterparty exposure and risk management practices. The Company's policy is that derivatives are to be used primarily for hedging purposes and mandates strict adherence to all applicable risk management policies. Derivative positions are monitored using techniques including, but not limited to, market valuation, value at risk, stress testing, and sensitivity analysis. Derivative instruments are recognized at fair value in the balance sheets as either assets or liabilities and are presented on a gross basis.

Energy-Related Derivatives

The Company enters into energy-related derivatives to hedge exposures to electricity, gas, and other fuel price changes. However, due to cost-based rate regulations and other various cost recovery mechanisms, the Company has limited exposure to market volatility in commodity fuel prices and prices of electricity. The Company manages fuel-hedging programs, implemented per the guidelines of the Alabama PSC, through the use of financial derivative contracts, which is expected to continue to mitigate price volatility.

To mitigate residual risks relative to movements in electricity prices, the Company may enter into physical fixed-price contracts for the purchase and sale of electricity through the wholesale electricity market. To mitigate residual risks relative to movements in gas prices, the Company may enter into fixed-price contracts for natural gas purchases; however, a significant portion of contracts are priced at market.

Energy-related derivative contracts are accounted for in one of three methods:

- *Regulatory Hedges* – Energy-related derivative contracts which are designated as regulatory hedges relate primarily to the Company's fuel hedging programs, where gains and losses are initially recorded as regulatory liabilities and assets, respectively, and then are included in fuel expense as the underlying fuel is used in operations and ultimately recovered through the energy cost recovery clause.
- *Cash Flow Hedges* – Gains and losses on energy-related derivatives designated as cash flow hedges which are mainly used to hedge anticipated purchases and sales and are initially deferred in OCI before being recognized in the statements of income in the same period as the hedged transactions are reflected in earnings.
- *Not Designated* – Gains and losses on energy-related derivative contracts that are not designated or fail to qualify as hedges are recognized in the statements of income as incurred.

Some energy-related derivative contracts require physical delivery as opposed to financial settlement, and this type of derivative is both common and prevalent within the electric industry. When an energy-related derivative contract is settled physically, any cumulative unrealized gain or loss is reversed and the contract price is recognized in the respective line item representing the actual price of the underlying goods being delivered.

At December 31, 2012, the net volume of energy-related derivative contracts for natural gas positions for the Company, together with the longest hedge date over which it is hedging its exposure to the variability in future cash flows for forecasted transactions and the longest date for derivatives not designated as hedges, were as follows:

	Gas	
Net Purchased mmBtu*	Longest Hedge Date	Longest Non-Hedge Date
(in millions)		
57	2017	—

* mmBtu – million British thermal units

For cash flow hedges, the amounts expected to be reclassified from OCI to revenue and fuel expense for the 12-month period ending December 31, 2013 are immaterial.

Interest Rate Derivatives

The Company may also enter into interest rate derivatives to hedge exposure to changes in interest rates. Derivatives related to existing variable rate securities or forecasted transactions are accounted for as cash flow hedges where the effective portion of the derivatives' fair value gains or losses is recorded in OCI and is reclassified into earnings at the same time the hedged transactions affect earnings. The derivatives employed as hedging instruments are structured to minimize ineffectiveness, which is recorded directly to earnings.

At December 31, 2012, there were no interest rate derivatives outstanding.

For the year ended December 31, 2012, the Company had realized net losses of $36 million upon termination of certain interest rate derivatives at the same time the related debt was issued. The effective portion of these losses has been deferred in OCI and is being amortized to interest expense over the life of the original interest rate derivative, reflecting the period in which the forecasted hedged transaction affects earnings.

The estimated pre-tax losses that will be reclassified from OCI to interest expense for the 12-month period ending December 31, 2013 are $3 million. The Company has deferred gains and losses that are expected to be amortized into earnings through 2035.

Derivative Financial Statement Presentation and Amounts

At December 31, 2012 and 2011, the fair value of energy-related derivatives and interest rate derivatives was reflected in the balance sheets as follows:

	Asset Derivatives			Liability Derivatives		
Derivative Category	**Balance Sheet Location**	**2012**	2011	**Balance Sheet Location**	**2012**	2011
		(in millions)			*(in millions)*	
Derivatives designated as hedging instruments for regulatory purposes						
Energy-related derivatives:						
	Other current assets	**$ 2**	$ —	Liabilities from risk management activities	**$ 14**	$ 36
	Other deferred charges and assets	**3**	—	Other deferred credits and liabilities	**4**	12
Total derivatives designated as hedging instruments for regulatory purposes		**$ 5**	$ —		**$ 18**	$ 48
Derivatives designated as hedging instruments in cash flow hedges						
Interest rate derivatives:						
	Other current assets	**$ —**	**$ —**	Liabilities from risk management activities	**$ —**	**$ 18**
Total		**$ 5**	$ —		**$ 18**	$ 66

All derivative instruments are measured at fair value. See Note 10 for additional information.

At December 31, 2012 and 2011, the pre-tax effect of unrealized derivative gains (losses) arising from energy-related derivative instruments designated as regulatory hedging instruments and deferred on the balance sheets was as follows:

	Unrealized Losses			Unrealized Gains		
Derivative Category	**Balance Sheet Location**	**2012**	2011	**Balance Sheet Location**	**2012**	2011
		(in millions)			*(in millions)*	
Energy-related derivatives:	Other regulatory assets, current	**$ (14)**	$ (36)	Other current liabilities	**$ 2**	$ —
	Other regulatory assets, deferred	**(4)**	(12)	Other regulatory liabilities, deferred	**3**	—
Total energy-related derivative gains (losses)		**$ (18)**	$ (48)		**$ 5**	$ —

For the years ended December 31, 2012, 2011, and 2010, the pre-tax effect of interest rate derivatives designated as cash flow hedging instruments on the statements of income was as follows:

Derivatives in Cash Flow Hedging Relationships	Gain (Loss) Recognized in OCI on Derivative (Effective Portion)			Gain (Loss) Reclassified from Accumulated OCI into Income (Effective Portion)			
					Amount		
Derivative Category	**2012**	2011	2010	**Statements of Income Location**	**2012**	2011	2010
	(in millions)				*(in millions)*		
Interest rate derivatives	**$ (18)**	$ (14)	$ —	Interest expense, net of amounts capitalized	**$ (3)**	$3	$ 3

There was no material ineffectiveness recorded in earnings for any period presented.

For the years ended December 31, 2012, 2011, and 2010, the pre-tax effect of energy-related derivatives not designated as hedging instruments on the statements of income was not material.

Contingent Features

The Company does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. There are certain derivatives that could require collateral, but not accelerated payment, in the event of various credit rating changes of certain affiliated companies. At December 31, 2012, the fair value of derivative liabilities with contingent features was $2 million.

At December 31, 2012, the Company had no collateral posted with its derivative counterparties; however, because of the joint and several liability features underlying these derivatives, the maximum potential collateral requirements arising from the credit-risk-related contingent features, at a rating below BBB- and/or Baa3, were $15 million.

Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. The Company participates in certain agreements that could require collateral in the event that one or more Southern Company system power pool participants has a credit rating change to below investment grade.

12. QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

Summarized quarterly financial information for 2012 and 2011 is as follows:

Quarter Ended	Operating Revenues	Operating Income	Net Income After Dividends on Preferred and Preference Stock
		(in millions)	
March 2012	**$ 1,216**	**$ 291**	**$ 126**
June 2012	**1,377**	**390**	**185**
September 2012	**1,637**	**544**	**280**
December 2012	**1,290**	**271**	**113**
March 2011	$ 1,320	$ 329	$ 152
June 2011	1,440	404	190
September 2011	1,671	523	264
December 2011	1,271	258	102

The Company's business is influenced by seasonal weather conditions.

SELECTED FINANCIAL AND OPERATING DATA 2008-2012
Alabama Power Company 2012 Annual Report

	2012	2011	2010	2009	2008
Operating Revenues (in millions)	**$ 5,520**	$ 5,702	$ 5,976	$ 5,529	$ 6,077
Net Income After Dividends on Preferred and Preference Stock (in millions)	**$ 704**	$ 708	$ 707	$ 670	$ 616
Cash Dividends on Common Stock (in millions)	**$ 684**	$ 774	$ 586	$ 523	$ 491
Return on Average Common Equity (percent)	**13.10**	13.19	13.31	13.27	13.30
Total Assets (in millions)	**$ 18,712**	$ 18,477	$ 17,994	$ 17,524	$ 16,536
Gross Property Additions (in millions)	**$ 940**	$ 1,016	$ 956	$ 1,323	$ 1,533
Capitalization (in millions):					
Common stock equity	**$ 5,398**	$ 5,342	$ 5,393	$ 5,237	$ 4,854
Preference stock	**343**	343	343	343	343
Redeemable preferred stock	**342**	342	342	342	342
Long-term debt	**5,929**	5,632	5,987	6,082	5,605
Total (excluding amounts due within one year)	**$ 12,012**	$ 11,659	$ 12,065	$ 12,004	$ 11,144
Capitalization Ratios (percent):					
Common stock equity	**44.9**	45.8	44.7	43.6	43.6
Preference stock	**2.9**	2.9	2.9	2.9	3.1
Redeemable preferred stock	**2.8**	2.9	2.8	2.8	3.0
Long-term debt	**49.4**	48.4	49.6	50.7	50.3
Total (excluding amounts due within one year)	**100.0**	100.0	100.0	100.0	100.0
Customers (year-end):					
Residential	**1,237,730**	1,231,574	1,235,128	1,229,134	1,220,046
Commercial	**196,177**	196,270	197,336	198,642	211,119
Industrial	**5,839**	5,844	5,770	5,912	5,906
Other	**748**	746	782	780	775
Total	**1,440,494**	1,434,434	1,439,016	1,434,468	1,437,846
Employees (year-end)	**6,778**	6,632	6,552	6,842	6,997

	2012	2011	2010	2009	2008
Operating Revenues (in millions):					
Residential	$ 2,068	$ 2,144	$ 2,283	$ 1,962	$ 1,998
Commercial	1,491	1,495	1,535	1,430	1,459
Industrial	1,346	1,306	1,231	1,080	1,381
Other	28	27	27	25	24
Total retail	4,933	4,972	5,076	4,497	4,862
Wholesale — non-affiliates	277	287	465	620	712
Wholesale — affiliates	111	244	236	237	308
Total revenues from sales of electricity	5,321	5,503	5,777	5,354	5,882
Other revenues	199	199	199	175	195
Total	$ 5,520	$ 5,702	$ 5,976	$ 5,529	$ 6,077
Kilowatt-Hour Sales (in millions):					
Residential	17,612	18,650	20,417	18,071	18,380
Commercial	13,963	14,173	14,719	14,186	14,551
Industrial	22,158	21,666	20,622	18,555	22,075
Other	214	214	216	218	201
Total retail	53,947	54,703	55,974	51,030	55,207
Wholesale — non-affiliates	4,196	4,330	8,655	14,317	15,204
Wholesale — affiliates	4,279	7,211	6,074	6,473	5,256
Total	62,422	66,244	70,703	71,820	75,667
Average Revenue Per Kilowatt-Hour (cents):					
Residential	11.74	11.50	11.18	10.86	10.87
Commercial	10.68	10.55	10.43	10.08	10.03
Industrial	6.07	6.03	5.97	5.82	6.26
Total retail	9.14	9.09	9.07	8.81	8.81
Wholesale	4.58	4.60	4.76	4.12	4.99
Total sales	8.52	8.31	8.17	7.45	7.77
Residential Average Annual Kilowatt-Hour Use Per Customer	14,252	15,138	16,570	14,716	15,162
Residential Average Annual Revenue Per Customer	$ 1,674	$ 1,740	$ 1,853	$ 1,597	$ 1,648
Plant Nameplate Capacity Ratings (year-end) (megawatts)	12,222	12,222	12,222	12,222	12,222
Maximum Peak-Hour Demand (megawatts):					
Winter	10,285	11,553	11,349	10,701	10,747
Summer	11,096	11,500	11,488	10,870	11,518
Annual Load Factor (percent)	61.3	60.6	62.6	59.8	60.9
Plant Availability (percent)*:					
Fossil-steam	88.6	88.7	92.9	88.5	90.1
Nuclear	94.5	94.7	88.4	93.3	94.1
Source of Energy Supply (percent):					
Coal	48.2	52.5	56.6	53.4	58.5
Nuclear	22.6	20.8	17.7	18.6	17.8
Hydro	4.1	4.6	5.0	7.9	2.9
Gas	16.8	15.3	14.0	11.8	9.2
Purchased power —					
From non-affiliates	2.0	0.9	1.6	2.0	2.9
From affiliates	6.3	5.9	5.1	6.3	8.7
Total	100.0	100.0	100.0	100.0	100.0

* Beginning in 2012, plant availability is calculated as a weighted equivalent availability.

GEORGIA POWER COMPANY

FINANCIAL SECTION

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING
Georgia Power Company 2012 Annual Report

The management of Georgia Power Company (the Company) is responsible for establishing and maintaining an adequate system of internal control over financial reporting as required by the Sarbanes-Oxley Act of 2002 and as defined in Exchange Act Rule 13a-15(f). A control system can provide only reasonable, not absolute, assurance that the objectives of the control system are met.

Under management's supervision, an evaluation of the design and effectiveness of the Company's internal control over financial reporting was conducted based on the framework in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, management concluded that the Company's internal control over financial reporting was effective as of December 31, 2012.

W. Paul Bowers
President and Chief Executive Officer

Ronnie R. Labrato
Executive Vice President, Chief Financial Officer, and Treasurer

February 27, 2013

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of
Georgia Power Company

We have audited the accompanying balance sheets and statements of capitalization of Georgia Power Company (the Company) (a wholly owned subsidiary of The Southern Company) as of December 31, 2012 and 2011, and the related statements of income, comprehensive income, common stockholder's equity, and cash flows for each of the three years in the period ended December 31, 2012. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such financial statements (pages II-231 to II-280) present fairly, in all material respects, the financial position of Georgia Power Company as of December 31, 2012 and 2011, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2012, in conformity with accounting principles generally accepted in the United States of America.

Deloitte & Touche LLP

Atlanta, Georgia
February 27, 2013

OVERVIEW

Business Activities

Georgia Power Company (the Company) operates as a vertically integrated utility providing electricity to retail customers within its traditional service area located within the State of Georgia and to wholesale customers in the Southeast.

Many factors affect the opportunities, challenges, and risks of the Company's business of selling electricity. These factors include the ability to maintain a constructive regulatory environment, to maintain and grow energy sales given economic conditions, and to effectively manage and secure timely recovery of costs. These costs include those related to projected long-term demand growth, increasingly stringent environmental standards, reliability, and fuel. In addition, the Company is currently constructing two new nuclear generating units at Plant Vogtle (Plant Vogtle Units 3 and 4) to increase its generation diversity. Appropriately balancing required costs and capital expenditures with customer prices will continue to challenge the Company for the foreseeable future. In 2010, the Georgia Public Service Commission (PSC) approved an Alternate Rate Plan for the years 2011 through 2013 (2010 ARP), including base rate increases of approximately $562 million, $20 million, $122 million, and $74 million effective January 1, 2011, January 1, 2012, April 1, 2012, and January 1, 2013, respectively. The Company is scheduled to file its next base rate case by July 1, 2013.

Key Performance Indicators

The Company continues to focus on several key performance indicators. These indicators include customer satisfaction, plant availability, system reliability, and net income after dividends on preferred and preference stock. The Company's financial success is directly tied to customer satisfaction. Key elements of ensuring customer satisfaction include outstanding service, high reliability, and competitive prices. Management uses customer satisfaction surveys and reliability indicators to evaluate the Company's results.

Peak season equivalent forced outage rate (Peak Season EFOR) is an indicator of fossil/hydro plant availability and efficient generation fleet operations during the months when generation needs are greatest. The rate is calculated by dividing the number of hours of forced outages by total generation hours. The 2012 fossil/hydro Peak Season EFOR did not meet the target due to an unplanned outage at Plant Bowen. Transmission and distribution system reliability performance is measured by the frequency and duration of outages. Performance targets for reliability are set internally based on historical performance. The 2012 performance exceeded target for these reliability measures.

Net income after dividends on preferred and preference stock is the primary measure of the Company's financial performance. The Company's 2012 results compared to its targets for some of these key indicators are reflected in the following chart:

Key Performance Indicator	2012 Target Performance	2012 Actual Performance
Customer Satisfaction	Top quartile in customer surveys	Top quartile
Peak Season EFOR — fossil/hydro	4.99% or less	5.31%
Net Income After Dividends on Preferred and Preference Stock	$1.14 billion	$1.17 billion

See RESULTS OF OPERATIONS herein for additional information on the Company's financial performance. The performance achieved in 2012 reflects the continued emphasis that management places on these indicators, as well as the commitment shown by employees in achieving or exceeding management's expectations.

Earnings

The Company's 2012 net income after dividends on preferred and preference stock totaled $1.2 billion representing a $23 million, or 2.0%, increase over the previous year. The increase was due primarily to lower operations and maintenance expenses resulting from cost containment efforts in 2012 and retail revenue rate effects as authorized under the 2010 ARP. These increases were partially offset by lower operating revenues as a result of milder weather in 2012 and a decrease in customer usage, lower allowance for funds used during construction (AFUDC) equity, higher depreciation and amortization, primarily as a result of completing construction of Plant McDonough-Atkinson Units 4 and 5, higher income taxes, and higher interest expense reflecting a 2011 settlement of tax litigation with the Georgia Department of Revenue (DOR).

The Company's 2011 net income after dividends on preferred and preference stock totaled $1.1 billion representing a $195 million, or 20.5%, increase over the previous year. The increase was due primarily to increases in retail base revenues, effective January 1, 2011, as authorized under the 2010 ARP and the financing costs associated with the construction of Plant Vogtle Units 3 and 4, collected through the Nuclear Construction Cost Recovery (NCCR) tariff, partially offset by closer to normal weather in 2011 when compared to 2010, higher non-fuel operating expenses, lower AFUDC equity, and higher income taxes. The increase was also due to a reduction in interest expense arising from the settlement of tax litigation with the Georgia DOR, partially offset by a decrease in the amortization of the regulatory liability related to other cost of removal obligations.

RESULTS OF OPERATIONS

A condensed income statement for the Company follows:

	Amount	Increase (Decrease) from Prior Year	
	2012	2012	2011
		(in millions)	
Operating revenues	$ 7,998	$ (802)	$ 451
Fuel	2,051	(738)	(313)
Purchased power	981	(122)	157
Other operations and maintenance	1,644	(133)	43
Depreciation and amortization	745	30	157
Taxes other than income taxes	374	5	25
Total operating expenses	5,795	(958)	69
Operating income	2,203	156	382
Allowance for equity funds used during construction	53	(43)	(51)
Interest expense, net of amounts capitalized	366	23	(32)
Other income (expense), net	(17)	(4)	4
Income taxes	688	63	172
Net income	1,185	23	195
Dividends on preferred and preference stock	17	—	—
Net income after dividends on preferred and preference stock	$ 1,168	$ 23	$ 195

Operating Revenues

Details of operating revenues were as follows:

	Amount	
	2012	2011
	(in millions)	
Retail — prior year	**$ 8,099**	$ 7,608
Estimated change in —		
Rates and pricing	**166**	703
Sales growth (decline)	**(26)**	(9)
Weather	**(147)**	(105)
Fuel cost recovery	**(730)**	(98)
Retail — current year	**7,362**	8,099
Wholesale revenues —		
Non-affiliates	**281**	341
Affiliates	**20**	32
Total wholesale revenues	**301**	373
Other operating revenues	**335**	328
Total operating revenues	**$ 7,998**	$ 8,800
Percent change	**(9.1)%**	5.4%

Retail base revenues of $4.8 billion in 2012 were flat compared to 2011 primarily due to milder weather in 2012, decreased customer usage, and lower contributions from market-driven rates from commercial and industrial customers, partially offset by base tariff increases effective April 1, 2012 related to placing Plant McDonough-Atkinson Units 4 and 5 in service, as well as for the collection of financing costs associated with the construction of Plant Vogtle Units 3 and 4 through the NCCR tariff and demand-side management programs effective January 1, 2012, as approved by the Georgia PSC, and the rate pricing effect of decreased customer usage. In 2012, residential base revenues increased $17 million, or 0.8%, commercial base revenues increased $11 million, or 0.6%, and industrial base revenues decreased $36 million, or 5.4%, compared to 2011. Economic uncertainty continues to impact residential, commercial, and industrial base revenues.

Retail base revenues of $4.8 billion in 2011 increased by $588 million, or 14.0%, from 2010 primarily due to increases authorized under the 2010 ARP, which became effective January 1, 2011. This increase was partially offset by closer to normal weather in 2011 compared to 2010. The increase in base revenues also included the collection of financing costs associated with the construction of Plant Vogtle Units 3 and 4 through the NCCR tariff effective January 1, 2011. See "Allowance for Funds Used During Construction Equity," "Interest Expense, Net of Amounts Capitalized," and FUTURE EARNINGS POTENTIAL – "PSC Matters – Nuclear Construction" herein for additional information. In 2011, residential base revenues increased $225 million, or 11.8%, commercial base revenues increased $236 million, or 14.1%, and industrial base revenues increased $118 million, or 21.4%, compared to 2010.

See "Energy Sales" below for a discussion of changes in the volume of energy sold, including changes related to sales growth (decline) and weather.

Electric rates include provisions to adjust billings for fluctuations in fuel costs, including the energy component of purchased power costs. Under these fuel cost recovery provisions, fuel revenues generally equal fuel expenses, including the fuel component of purchased power, and do not affect net income. The Company further lowered fuel rates effective January 1, 2013. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Fuel Cost Recovery" herein for additional information.

Wholesale revenues from sales to non-affiliated utilities were as follows:

	2012	2011	2010
		(in millions)	
Other power sales —			
Capacity and other	$ 177	$ 177	$ 155
Energy	104	164	194
Total	281	341	349
Unit power sales —			
Capacity	—	—	18
Energy	—	—	13
Total	—	—	31
Total non-affiliated	$ 281	$ 341	$ 380

Wholesale revenues from sales to non-affiliates consist of power purchase agreements (PPA) and short-term opportunity sales, and, in 2010, from a unit power sales agreement. Capacity revenues reflect the recovery of fixed costs and a return on investment. Wholesale revenues from sales to non-affiliates will vary depending on fuel prices, the market prices of wholesale energy compared to the cost of the Company's and the Southern Company system's generation, demand for energy within the Southern Company system's service territory, and the availability of the Southern Company system's generation. Increases and decreases in energy revenues that are driven by fuel prices are accompanied by an increase or decrease in fuel costs and do not have a significant impact on net income. Short-term opportunity sales are made at market-based rates that generally provide a margin above the Company's variable cost of energy.

Revenues from other non-affiliated sales decreased $60 million, or 17.6%, in 2012 and $8 million, or 2.3%, in 2011. The decrease in 2012 was primarily due to a 24.9% decrease in kilowatt-hour (KWH) sales due to lower demand resulting from milder weather and the availability of market energy at a lower cost than Company-owned generation. The decrease in 2011 was primarily due to a 16.3% decrease in KWH sales reflecting lower demand resulting from both more normal weather in 2011 compared to 2010 and the lower market costs of available energy compared to Company-owned generation.

Wholesale revenues from sales to affiliated companies will vary from year to year depending on demand and the availability and cost of generating resources at each company. These affiliated sales and purchases are made in accordance with the Intercompany Interchange Contract (IIC), as approved by the Federal Energy Regulatory Commission (FERC). These transactions do not have a significant impact on earnings since this energy is generally sold at marginal cost. In 2012 and 2011, wholesale revenues from sales to affiliates decreased $12 million and $21 million from the prior year, respectively, due to decreases of 4.2% and 37.4%, respectively, in KWH sales as a result of lower demand because the market cost of available energy was lower than the cost of Company-owned generation. In 2012, lower demand also resulted from the milder weather.

Other operating revenues increased $7 million, or 2.1%, in 2012 from the prior year primarily due to higher revenues from outdoor lighting and pole attachments. Other operating revenues increased $20 million, or 6.5%, in 2011 from the prior year primarily due to new contracts that replaced the transmission component of a unit power sales agreement that expired in 2010 and increased usage of the Company's transmission system by non-affiliate companies.

Energy Sales

Changes in revenues are influenced heavily by the change in the volume of energy sold from year to year. KWH sales for 2012 and the percent change by year were as follows:

	Total KWHs	Total KWH Percent Change		Weather-Adjusted Percent Change	
	2012	2012	2011	2012	2011
	(in billions)				
Residential	**25.7**	**(5.4)%**	(7.5)%	**0.3 %**	(0.4)%
Commercial	**32.3**	**(1.9)**	(2.8)	**(0.6)**	(0.4)
Industrial	**23.1**	**(1.8)**	1.3	**(1.2)**	1.6
Other	**0.7**	**(2.5)**	(0.9)	**(2.0)**	(0.6)
Total retail	**81.8**	**(3.0)**	(3.3)	**(0.5)%**	0.2 %
Wholesale					
Non-affiliates	**2.9**	**(24.9)**	(16.3)		
Affiliates	**0.6**	**(4.2)**	(37.4)		
Total wholesale	**3.5**	**(22.0)**	(20.0)		
Total energy sales	**85.3**	**(4.0)%**	(4.3)%		

Changes in retail energy sales are comprised of changes in electricity usage by customers, changes in weather, and changes in the number of customers.

In 2012, KWH sales for all customer classes decreased compared to 2011 primarily due to milder weather in 2012. Economic uncertainty continues to impact sales for all customer classes as well; however, an increase of approximately 15,000 new residential customers in 2012 contributed to a slight increase in weather-adjusted residential KWH sales.

In 2011, residential and commercial KWH sales decreased compared to 2010 primarily due to closer to normal weather in 2011 compared to 2010. Industrial KWH sales increased in 2011 compared to 2010 primarily due to increased demand in the primary metals sector.

See "Operating Revenues" above for a discussion of significant changes in wholesale sales to non-affiliates and affiliated companies.

Fuel and Purchased Power Expenses

Fuel costs constitute the single largest expense for the Company. The mix of fuel sources for generation of electricity is determined primarily by demand, the unit cost of fuel consumed, and the availability of generating units. Additionally, the Company purchases a portion of its electricity needs from the wholesale market.

Details of the Company's generation and purchased power were as follows:

	2012	2011	2010
Total generation *(billions of KWHs)*	**59.8**	65.5	75.3
Total purchased power *(billions of KWHs)*	**28.7**	26.8	21.7
Sources of generation *(percent)* -			
Coal	**39**	62	67
Nuclear	**27**	23	21
Gas	**33**	13	10
Hydro	**1**	2	2
Cost of fuel, generated *(cents per net KWH)* -			
Coal	**4.63**	4.70	4.53
Nuclear	**0.87**	0.78	0.66
Gas	**3.02**	4.92	5.75
Average cost of fuel, generated *(cents per net KWH)*	**3.07**	3.80	3.82
Average cost of purchased power *(cents per net KWH)* *	**4.24**	5.38	5.64

* Average cost of purchased power includes fuel purchased by the Company for tolling agreements where power is generated by the provider.

Fuel and purchased power expenses were $3.0 billion in 2012, a decrease of $860 million, or 22.1%, compared to 2011. The decrease was primarily due to a $703 million decrease in the average cost of fuel and purchased power primarily due to lower natural gas prices and a $259 million decrease in the volume of KWHs generated as a result of lower customer demand from milder weather in 2012. These decreases were partially offset by a $102 million increase in the volume of KWHs purchased as the market cost of available energy was lower than the additional Company-owned generation available.

Fuel and purchased power expenses were $3.9 billion in 2011, a decrease of $156 million, or 3.9%, compared to 2010. The decrease was primarily due to an $86 million decrease in the average cost of purchased power and gas, partially offset by increases in the average cost of coal and nuclear fuel. The decrease was also due to a $358 million decrease related to fewer KWHs generated as a result of lower customer demand, partially offset by a $288 million increase in KWHs purchased as the market cost of energy was lower than the additional Company-owned generation available.

From an overall global market perspective, coal prices decreased from levels experienced in 2011 due to lower demand. In the U.S., this decrease was due primarily to relatively lower domestic natural gas prices that contributed to displacement of coal generation by natural gas-fueled generating units. Lower domestic natural gas prices in 2012 were driven by continued robust supplies, including production from shale gas, and only modest increases in overall U.S. consumption.

Uranium prices began to decrease during the second half of 2012 as extended reactor shutdowns in Europe and Asia caused global demand for uranium to drop below the level of previous years, while production increased. Changes in the cost of fuel for nuclear generation tend to lag behind changes in uranium market prices. Even though uranium prices decreased slightly during 2012, the cost of fuel for nuclear generation increased in 2012, reflecting the higher uranium prices from previous years when the uranium was purchased.

Fuel and purchased power energy transactions do not have a significant impact on earnings since these fuel expenses are generally offset by fuel revenues through the Company's fuel cost recovery mechanism. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Fuel Cost Recovery" herein for additional information.

Fuel

Fuel expense was $2.1 billion in 2012, a decrease of $738 million, or 26.5%, compared to 2011. The decrease was primarily due to an 8.4% decrease in KWHs generated as a result of lower demand and a 19.2% decrease in the average cost of fuel per KWH generated primarily due to lower natural gas prices. In addition, the Company's fuel mix for generation changed from 62% coal and 13% natural gas in 2011 to 39% coal and 33% natural gas in 2012 primarily due to the completion of the Plant McDonough-Atkinson combined cycle units. Fuel expenses were $2.8 billion in 2011, a decrease of $313 million, or 10.1%, compared to 2010. The decrease was primarily due to a 14.4% decrease in the average cost of gas and a 12.7% decrease in KWHs generated, partially offset by 18.2% and 3.8% increases in the average cost of nuclear fuel and coal, respectively.

Purchased Power - Non-Affiliates

Purchased power expense from non-affiliates was $315 million in 2012, a decrease of $75 million, or 19.2%, compared to 2011. The decrease was due to a 23.8% decrease in the average cost per KWH purchased primarily due to lower natural gas prices, partially offset by a 7.0% increase in the volume of KWHs purchased as the market cost of available energy was lower than the cost of additional Company-owned generation. Purchased power expense from non-affiliates was $390 million in 2011, an increase of $22 million, or 6.0%, compared to 2010. The increase was primarily due to a 13.1% increase in the volume of KWHs purchased as the market cost of available energy was lower than the additional Company-owned generation, partially offset by a 4.2% decrease in the average cost per KWH purchased primarily due to lower natural gas prices.

Energy purchases from non-affiliates will vary depending on the market prices of wholesale energy as compared to the cost of the Southern Company system's generation, demand for energy within the Southern Company system's service territory, and the availability of the Southern Company system's generation.

Purchased Power - Affiliates

Purchased power expense from affiliates was $666 million in 2012, a decrease of $47 million, or 6.6%, compared to 2011. The decrease was primarily due to a 20.2% decrease in the average cost per KWH purchased, reflecting lower natural gas prices, partially offset by a 7.1% increase in the volume of KWHs purchased as the cost of the available energy was lower than the cost of Company-owned generation available. Purchased power expense from affiliates was $713 million in 2011, an increase of $135 million, or 23.4%, compared to 2010. The increase was primarily due to a 26.8% increase in the volume of KWHs purchased as the cost of available energy was lower than the cost of Company-owned generation available, partially offset by a 2.9% decrease in the average cost per KWH purchased, reflecting lower natural gas prices.

Energy purchases from affiliates will vary depending on the demand and the availability and cost of generating resources at each company within the Southern Company system. These purchases are made in accordance with the IIC or other contractual agreements, all as approved by the FERC.

Other Operations and Maintenance Expenses

In 2012, other operations and maintenance expenses decreased $133 million, or 7.5%, compared to 2011. The decrease was primarily due to the timing of planned generation outages and decreases in transmission and distribution maintenance as a result of cost containment efforts to offset the effects of milder weather in 2012 and a decrease in uncollectible account expense of $24 million, as a result of lower revenues, a slightly improving economy, and change in the customer deposit policy, partially offset by a net increase in pension and other employee benefit-related expenses of $14 million.

In 2011, other operations and maintenance expenses increased $43 million, or 2.5%, compared to 2010. The increase was due to a $22 million increase in customer assistance expenses related to new demand side management programs in 2011, an $8 million increase in uncollectible account expense as a result of higher revenues and economic conditions, and a $6 million increase in workers compensation expense resulting from a higher volume of claims.

Depreciation and Amortization

Depreciation and amortization increased $30 million, or 4.2%, in 2012 compared to 2011. The increase was primarily due to an increase of $50 million in depreciation on additional plant in service primarily related to new generation at Plant McDonough-Atkinson Units 4 and 5, partially offset by $27 million in amortization of the regulatory liability for state income tax credits as authorized by the Georgia PSC. See Note 1 to the financial statements under "Regulatory Assets and Liabilities" for additional information.

Depreciation and amortization increased $157 million, or 28.1%, in 2011 compared to 2010. The increase was primarily due to a $142 million decrease in the amortization of the regulatory liability related to other cost of removal obligations as authorized by the Georgia PSC. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Rate Plans" herein and Note 3 to the financial statements under "Retail Regulatory Matters – Rate Plans" for additional information.

See Note 1 to the financial statements under "Depreciation and Amortization" for additional information.

Taxes Other Than Income Taxes

In 2012, taxes other than income taxes increased $5 million, or 1.4%, compared to 2011. The increase was primarily due to a $20 million increase in property taxes, partially offset by a $12 million decrease in municipal franchise fees resulting from lower retail revenues in 2012.

In 2011, taxes other than income taxes increased $25 million, or 7.3%, compared to 2010 primarily due to a $17 million increase in property taxes and a $9 million increase in municipal franchise fees related to an increase in retail revenues.

Allowance for Funds Used During Construction Equity

AFUDC equity decreased $43 million, or 44.8%, in 2012 compared to the prior year primarily due to the completion of Plant McDonough-Atkinson Units 4, 5, and 6 in December 2011, April 2012, and October 2012, respectively.

AFUDC equity decreased $51 million, or 34.7%, in 2011 compared to the prior year primarily due to the inclusion of construction costs for Plant Vogtle Units 3 and 4 in rate base effective January 1, 2011 in accordance with the Georgia Nuclear Energy Financing Act and a Georgia PSC order. This action reduced the amount of AFUDC capitalized with an offsetting increase in operating revenues through the NCCR tariff. See Note 3 to the financial statements under "Retail Regulatory Matters – Nuclear Construction."

Interest Expense, Net of Amounts Capitalized

In 2012, interest expense, net of amounts capitalized increased $23 million, or 6.7%, from the prior year primarily due to a $23 million reduction in interest expense in 2011 resulting from the settlement of litigation with the Georgia DOR, a $16 million decrease in AFUDC debt in 2012 primarily due to the completion of Plant McDonough-Atkinson Units 4 and 5 discussed previously, and a net increase of $18 million in interest expense related to outstanding senior notes. The increase was partially offset by reductions in expense related to pollution control revenue bonds, the redemption of all trust preferred securities in September 2011, and the conclusion of certain state and federal income tax audits in 2012 of $13 million, $9 million, and $9 million, respectively.

In 2011, interest expense, net of amounts capitalized decreased $32 million, or 8.5%, from the prior year primarily due to a reduction of $23 million in interest expense related to the settlement of litigation with the Georgia DOR and lower interest expense on existing variable rate pollution control revenue bonds, partially offset by a reduction in AFUDC debt due to the inclusion of construction costs for Plant Vogtle Units 3 and 4 in rate base as discussed previously.

Income Taxes

Income taxes increased $63 million, or 10.1%, in 2012 compared to the prior year primarily due to higher pre-tax earnings, an increase in non-deductible book depreciation, and a decrease in non-taxable AFUDC equity, partially offset by state income tax credits.

Income taxes increased $172 million, or 38.0%, in 2011 compared to the prior year primarily due to higher pre-tax earnings, a decrease in non-taxable AFUDC equity, and the recognition in 2010 of certain state income tax credits.

See "Allowance for Funds Used During Construction Equity" herein for additional information.

Effects of Inflation

The Company is subject to rate regulation that is generally based on the recovery of historical and projected costs. The effects of inflation can create an economic loss since the recovery of costs could be in dollars that have less purchasing power. Any adverse effect of inflation on the Company's results of operations has not been substantial in recent years.

FUTURE EARNINGS POTENTIAL

General

The Company operates as a vertically integrated utility providing electricity to retail customers within its traditional service area located within the State of Georgia and to wholesale customers in the Southeast. Prices for electricity provided by the Company to retail customers are set by the Georgia PSC under cost-based regulatory principles. Prices for wholesale electricity sales, interconnecting transmission lines, and the exchange of electric power are regulated by the FERC. Retail rates and earnings are reviewed and may be adjusted periodically within certain limitations. See ACCOUNTING POLICIES – "Application of Critical Accounting Policies and Estimates – Electric Utility Regulation" herein and Note 3 to the financial statements under "Retail Regulatory Matters" for additional information about regulatory matters.

The results of operations for the past three years are not necessarily indicative of future earnings potential. The level of the Company's future earnings depends on numerous factors that affect the opportunities, challenges, and risks of the Company's business of selling electricity. These factors include the Company's ability to maintain a constructive regulatory environment that continues to allow for the timely recovery of prudently-incurred costs during a time of increasing costs and the successful completion of ongoing construction projects. Future earnings in the near term will depend, in part, upon maintaining energy sales which is subject to a number of factors. These factors include weather, competition, new energy contracts with neighboring utilities, energy conservation practiced by customers, the price of electricity, the price elasticity of demand, and the rate of economic growth or decline in the Company's service territory. Changes in economic conditions impact sales for the Company,

and the pace of the economic recovery remains uncertain. The timing and extent of the economic recovery will impact growth and may impact future earnings.

In 2012, the Company's generating capacity increased 1,680 megawatts (MWs), net of retirements of 284 MWs, due to the completion of Plant McDonough-Atkinson Units 5 and 6. New generating capacity is approved by the Georgia PSC through the Integrated Resource Plan (IRP) process. See "PSC Matters – Integrated Resource Plans" herein and Note 3 to the financial statements under "Retail Regulatory Matters – Integrated Resource Plans" for additional information.

Environmental Matters

Compliance costs related to federal and state environmental statutes and regulations could affect earnings if such costs cannot continue to be fully recovered in rates on a timely basis. Environmental compliance spending over the next several years may differ materially from the amounts estimated. The timing, specific requirements, and estimated costs could change as environmental statutes and regulations are adopted or modified. The Company's environmental compliance cost recovery (ECCR) tariff allows for the recovery of capital and operations and maintenance costs related to environmental controls mandated by state and federal regulations. Further, higher costs that are recovered through regulated rates could contribute to reduced demand for electricity, which could negatively affect results of operations, cash flows, and financial condition. See Note 3 to the financial statements under "Environmental Matters" for additional information.

New Source Review Actions

In 1999, the Environmental Protection Agency (EPA) brought a civil action in the U.S. District Court for the Northern District of Georgia against certain Southern Company subsidiaries, including the Company, alleging that these subsidiaries had violated the New Source Review (NSR) provisions of the Clean Air Act and related state laws at certain coal-fired generating facilities. The EPA alleged NSR violations at three coal-fired generating facilities operated by the Company and five coal-fired generating facilities operated by Alabama Power Company (Alabama Power). The civil action sought penalties and injunctive relief, including an order requiring installation of the best available control technology at the affected units. The case against the Company was administratively closed in 2001 and has not been reopened.

The Company believes it complied with applicable laws and regulations in effect at the time the work in question took place. The Clean Air Act authorizes maximum civil penalties of $25,000 to $37,500 per day, per violation, depending on the date of the alleged violation. An adverse outcome could require substantial capital expenditures that cannot be determined at this time and could possibly require payment of substantial penalties. Such expenditures could affect future results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates. The ultimate outcome of this matter cannot be determined at this time.

Climate Change Litigation

Kivalina Case

In 2008, the Native Village of Kivalina and the City of Kivalina filed a lawsuit in the U.S. District Court for the Northern District of California against several electric utilities (including Southern Company), several oil companies, and a coal company. The plaintiffs allege that the village is being destroyed by erosion allegedly caused by global warming that the plaintiffs attribute to emissions of greenhouse gases by the defendants. The plaintiffs assert claims for public and private nuisance and contend that some of the defendants (including Southern Company) acted in concert and are therefore jointly and severally liable for the plaintiffs' damages. The suit seeks damages for lost property values and for the cost of relocating the village, which is alleged to be $95 million to $400 million. In 2009, the U.S. District Court for the Northern District of California granted the defendants' motions to dismiss the case. On September 21, 2012, the U.S. Court of Appeals for the Ninth Circuit upheld the U.S. District Court for the Northern District of California's dismissal of the case. On November 27, 2012, the U.S. Court of Appeals for the Ninth Circuit denied the plaintiffs' request for review of the decision. On February 25, 2013, the plaintiffs filed a petition for writ of certiorari with the U.S. Supreme Court. Southern Company believes that these claims are without merit. The ultimate outcome of this matter cannot be determined at this time.

Hurricane Katrina Case

In 2005, immediately following Hurricane Katrina, a lawsuit was filed in the U.S. District Court for the Southern District of Mississippi by Ned Comer on behalf of Mississippi residents seeking recovery for property damage and personal injuries caused by Hurricane Katrina. In 2006, the plaintiffs amended the complaint to include Southern Company and many other electric utilities, oil companies, chemical companies, and coal producers. The plaintiffs allege that the defendants contributed to climate change, which contributed to the intensity of Hurricane Katrina. In 2007, the U.S. District Court for the Southern District of Mississippi dismissed the case. On appeal to the U.S. Court of Appeals for the Fifth Circuit, a three-judge panel reversed the U.S.

District Court for the Southern District of Mississippi, holding that the case could proceed, but, on rehearing, the full U.S. Court of Appeals for the Fifth Circuit dismissed the plaintiffs' appeal, resulting in reinstatement of the decision of the U.S. District Court for the Southern District of Mississippi in favor of the defendants. In May 2011, the plaintiffs filed an amended version of their class action complaint, arguing that the earlier dismissal was on procedural grounds and under Mississippi law the plaintiffs have a right to re-file. The amended complaint was also filed against numerous chemical, coal, oil, and utility companies, including the Company. On March 20, 2012, the U.S. District Court for the Southern District of Mississippi dismissed the plaintiffs' amended complaint. On April 16, 2012, the plaintiffs appealed the case to the U.S. Court of Appeals for the Fifth Circuit. The Company believes that these claims are without merit. The ultimate outcome of this matter cannot be determined at this time.

Environmental Statutes and Regulations

General

The Company's operations are subject to extensive regulation by state and federal environmental agencies under a variety of statutes and regulations governing environmental media, including air, water, and land resources. Applicable statutes include the Clean Air Act; the Clean Water Act; the Comprehensive Environmental Response, Compensation, and Liability Act; the Resource Conservation and Recovery Act; the Toxic Substances Control Act; the Emergency Planning & Community Right-to-Know Act; the Endangered Species Act; and related federal and state regulations. Compliance with these environmental requirements involves significant capital and operating costs, a major portion of which is expected to be recovered through existing ratemaking provisions. Through 2012, the Company had invested approximately $4.0 billion in environmental capital retrofit projects to comply with these requirements, with annual totals of approximately $152 million, $113 million, and $217 million in 2012, 2011, and 2010, respectively. The Company expects that capital expenditures to comply with existing statutes and regulations, including capital expenditures and compliance costs associated with the EPA's final Mercury and Air Toxics Standards (MATS) rule, will be a total of approximately $1.3 billion from 2013 through 2015, with annual totals of approximately $476 million, $441 million, and $392 million for 2013, 2014, and 2015, respectively.

The Company continues to monitor the development of the EPA's proposed water and coal combustion byproducts rules and to evaluate compliance options. Based on its preliminary analysis and an assumption that coal combustion byproducts will continue to be regulated as non-hazardous solid waste under the proposed rule, the Company does not anticipate that material compliance costs with respect to these proposed rules will be required during the period of 2013 through 2015. The ultimate capital expenditures and compliance costs with respect to these proposed rules, including additional expenditures required after 2015, will be dependent on the requirements of the final rules and regulations adopted by the EPA and the outcome of any legal challenges to these rules. See "Water Quality" and "Coal Combustion Byproducts" herein for additional information.

The Company's ultimate environmental compliance strategy, including potential unit retirement and replacement decisions, and future environmental capital expenditures will be affected by the final requirements of new or revised environmental regulations and regulations relating to global climate change that are promulgated, including the proposed environmental regulations described below; the outcome of any legal challenges to the environmental rules; the cost, availability, and existing inventory of emissions allowances; and the Company's fuel mix. Compliance costs may arise from existing unit retirements, installation of additional environmental controls, upgrades to the transmission system, and adding or changing fuel sources for certain existing units. The ultimate outcome of these matters cannot be determined at this time. See "PSC Matters – Integrated Resource Plans" herein for additional information on planned unit retirements and fuel conversions.

Southern Electric Generating Company (SEGCO), a subsidiary of the Company, is jointly owned with Alabama Power. As part of its environmental compliance strategy, SEGCO plans to add natural gas as the primary fuel source for its generating units in 2015. The capacity of SEGCO's units is sold equally to the Company and Alabama Power through a PPA. The impact of SEGCO's ultimate compliance strategy on such PPA costs cannot be determined at this time; however, if such costs cannot continue to be recovered through retail rates, they could have a material financial impact on the Company's financial statements. See Note 4 to the Company's financial statements for additional information.

Compliance with any new federal or state legislation or regulations relating to air quality, water, coal combustion byproducts, global climate change, or other environmental and health concerns could significantly affect the Company. Although new or revised environmental legislation or regulations could affect many areas of the Company's operations, the full impact of any such changes cannot be determined at this time. Additionally, many of the Company's commercial and industrial customers may also be affected by existing and future environmental requirements, which for some may have the potential to ultimately affect their demand for electricity.

Air Quality

Compliance with the Clean Air Act and resulting regulations has been and will continue to be a significant focus for the Company. Since 1990, the Company has spent approximately $3.6 billion in reducing and monitoring emissions pursuant to the Clean Air Act. Additional controls are currently planned or under consideration to further reduce air emissions, maintain compliance with existing regulations, and meet new requirements.

The EPA regulates ground level ozone concentrations through implementation of an eight-hour ozone air quality standard. In 2008, the EPA adopted a more stringent eight-hour ozone National Ambient Air Quality Standard, which it began to implement in September 2011. On May 21, 2012, the EPA published its final determination of nonattainment areas based on the 2008 eight-hour ozone air quality standards. The only area within the Company's service territory designated as a nonattainment area is a 15-county area within metropolitan Atlanta.

The EPA regulates fine particulate matter concentrations on an annual and 24-hour average basis. All areas within the Company's service territory have achieved attainment with the 1997 and 2006 particulate matter National Ambient Air Quality Standards. Redesignation requests for nonattainment areas in Georgia are still pending with the EPA. On January 15, 2013, the EPA published a final rule that increases the stringency of the annual fine particulate matter standard. The new standard could result in the designation of new nonattainment areas within the Company's service territory.

Final revisions to the National Ambient Air Quality Standard for sulfur dioxide (SO_2), including the establishment of a new one-hour standard, became effective in 2010 (SO_2 Rule). The EPA plans to issue area designations under this new standard in June 2013, and areas within the Company's service territory could ultimately be designated as nonattainment. Implementation of the revised SO_2 standard could require additional reductions in SO_2 emissions and increased compliance and operational costs.

Revisions to the National Ambient Air Quality Standard for nitrogen dioxide (NO_2), which established a new one-hour standard, became effective in 2010. On February 29, 2012, the new NO_2 standard became effective. The EPA designated the entire country as "unclassifiable/attainment" under the new standard, with no nonattainment areas designated. However, the new NO_2 standard could result in significant additional compliance and operational costs for units that require new source permitting.

The Company's service territory is subject to the requirements of the Clean Air Interstate Rule (CAIR), which calls for phased reductions in SO_2 and nitrogen oxide (NO_x) emissions from power plants in 28 eastern states. In 2008, the U.S. Court of Appeals for the District of Columbia Circuit issued decisions invalidating CAIR, but left CAIR compliance requirements in place while the EPA developed a new rule. In August 2011, the EPA adopted the Cross State Air Pollution Rule (CSAPR) to replace CAIR effective January 1, 2012. However, in December 2011, the U.S. Court of Appeals for the District of Columbia Circuit stayed the rule and, on August 21, 2012, vacated CSAPR in its entirety and directed the EPA to continue to administer CAIR pending the EPA's development of a valid replacement. On January 24, 2013, the U.S. Court of Appeals for the District of Columbia Circuit denied requests by the EPA and other parties for rehearing.

The EPA finalized the Clean Air Visibility Rule (CAVR) in 2005, with a goal of restoring natural visibility conditions in certain areas (primarily national parks and wilderness areas) by 2064. The rule involves the application of best available retrofit technology (BART) to certain sources built between 1962 and 1977 and any additional emissions reductions necessary for each designated area to achieve reasonable progress toward the natural visibility conditions goal by 2018 and for each 10-year period thereafter. In 2005, the EPA determined that compliance with CAIR satisfies BART obligations under CAVR, but, on June 7, 2012, the EPA issued a final rule replacing CAIR with CSAPR as an alternative means of satisfying BART obligations. The vacatur of CSAPR creates additional uncertainty with respect to whether additional controls may be required for CAVR and BART compliance.

On February 16, 2012, the EPA published the final MATS rule, which imposes stringent emissions limits for acid gases, mercury, and particulate matter on coal - and oil-fired electric utility steam generating units. Compliance for existing sources is required by April 16, 2015, unless a one-year compliance extension is granted by the state or local air permitting agency.

Numerous petitions for administrative reconsideration of the MATS rule, including a petition by the Company, have been filed with the EPA. On November 30, 2012, the EPA proposed a reconsideration of certain new source and startup/shutdown issues. The EPA plans to complete its reconsideration rulemaking by March 2013. Challenges to the final rule have also been filed in the U.S. District Court for the District of Columbia by numerous states, environmental organizations, industry groups, and others.

On August 29, 2012, the EPA published proposed revisions to the New Source Performance Standard (NSPS) for Stationary Combustion Turbines (CTs). If finalized as proposed, the revisions would apply the NSPS to all new, reconstructed, and modified CTs (including CTs at combined cycle units), during all periods of operation, including startup and shutdown, and alter the criteria for determining when an existing CT has been reconstructed.

On January 31, 2013, the EPA published the final Industrial Boiler Maximum Achievable Control Technology (IB MACT) rule establishing emissions limits and/or work practice standards for various hazardous air pollutants emitted from industrial boilers, including biomass boilers and start-up boilers. Compliance for existing sources will be required by early 2016. Compliance for new sources will begin upon startup. The Company is evaluating the impact of this final rule and other environmental regulations on the possible conversion of Plant Mitchell Unit 3 from coal to biomass.

On February 12, 2013, the EPA proposed a rule that would require certain states to revise the provisions of their State Implementation Plans (SIPs) relating to the regulation of excess emissions at industrial facilities, including fossil fuel-fired generating facilities, during periods of startup, shut-down, or malfunction (SSM). The EPA proposes a determination that the SSM provisions in the SIPs for 36 states, including Georgia, Alabama, and Florida, do not meet the requirements of the Clean Air Act and must be revised within 18 months of the date on which the EPA publishes the final rule. If finalized as proposed, this new requirement could result in significant additional compliance and operational costs.

The Company has developed and continually updates a comprehensive environmental compliance strategy to assess compliance obligations associated with the existing and new environmental requirements discussed above. The impacts of the eight-hour ozone, fine particulate matter, SO_2 and NO_2 standards, CAIR and any future replacement rule, CAVR, the MATS rule, the NSPS for CTs, the IB MACT rule, and the SSM rule on the Company cannot be determined at this time and will depend on the specific provisions of recently finalized and future rules, the resolution of pending and future legal challenges, and the development and implementation of rules at the state level. These regulations could result in significant additional compliance costs that could affect future unit retirement and replacement decisions and results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates. Further, higher costs that are recovered through regulated rates could contribute to reduced demand for electricity, which could negatively impact results of operations, cash flows, and financial condition.

In addition to the federal air quality laws described above, the Company is also subject to the requirements of the 2007 State of Georgia Multi-Pollutant Rule. The Multi-Pollutant Rule is designed to reduce emissions of mercury, SO_2, and NOx state-wide by requiring the installation of specified control technologies at certain coal-fired generating units by specific dates between December 31, 2008 and December 31, 2015. The State of Georgia also adopted a companion rule that requires a 95% reduction in SO2 emissions from the controlled units on the same or similar timetable. Through December 31, 2012, the Company had installed the required controls on 11 of its largest coal-fired generating units and is in the process of installing the required controls on two additional units. On February 21, 2013, the State of Georgia released proposed revisions for both the Multi-Pollutant Rule and the SO_2 Rule revising the compliance dates for those units yet to be controlled to make them consistent with the April 2015 compliance date for the MATS rule. According to the State of Georgia, the proposed revisions would also allow the units at Plant Yates to use natural gas as the primary fuel as an alternative to installing controls under the Multi-Pollutant Rule. The revisions to the Multi-Pollutant Rule and the SO_2 Rule are expected to be finalized in April 2013.

The ultimate outcome of these matters cannot be determined at this time.

Water Quality

In April 2011, the EPA published a proposed rule that establishes standards for reducing effects on fish and other aquatic life caused by cooling water intake structures at existing power plants and manufacturing facilities. The rule also addresses cooling water intake structures for new units at existing facilities. Compliance with the proposed rule could require changes to existing cooling water intake structures at certain of the Company's generating facilities, and new generating units constructed at existing plants would be required to install closed cycle cooling towers. The EPA has entered into an amended settlement agreement to extend the deadline for issuing a final rule until June 27, 2013. If finalized as proposed, some of the Company's facilities may be subject to significant additional capital expenditures and compliance costs that could affect future unit retirement and replacement decisions. Also, results of operations, cash flows, and financial condition could be significantly impacted if such costs are not recovered through regulated rates. The ultimate outcome of this rulemaking will depend on the final rule and the outcome of any legal challenges and cannot be determined at this time.

The EPA has announced its determination that revision of the current effluent guidelines for steam electric power plants is warranted and has stated that it intends to propose such revisions by April 2013 and finalize the revisions by May 2014. New advanced wastewater treatment requirements are expected and may result in the installation of additional controls on certain of the Company's facilities, which could result in significant additional capital expenditures and compliance costs that could affect future unit retirement and replacement decisions. The impact of the revised guidelines will depend on the specific technology requirements of the final rule and, therefore, cannot be determined at this time.

Coal Combustion Byproducts

The Company currently operates 11 electric generating plants with on-site coal combustion byproducts, including coal ash and gypsum storage facilities. In addition to on-site storage, the Company also sells a portion of its coal combustion byproducts to third parties for beneficial reuse. Historically, individual states have regulated coal combustion byproducts and the States of Georgia and Alabama have their own separate regulatory parameters. The Company has a routine and robust inspection program in place to ensure the integrity of its coal ash surface impoundments and compliance with applicable regulations.

The EPA continues to evaluate the regulatory program for coal combustion byproducts, including coal ash and gypsum, under federal solid and hazardous waste laws. In 2010, the EPA published a proposed rule that requested comments on two potential regulatory options for the management and disposal of coal combustion byproducts: regulation as a solid waste or regulation as if the materials technically constituted a hazardous waste. Adoption of either option could require closure of, or significant change to, existing storage facilities and construction of lined landfills, as well as additional waste management and groundwater monitoring requirements. Under both options, the EPA proposes to exempt the beneficial reuse of coal combustion byproducts from regulation; however, a hazardous or other designation indicative of heightened risk could limit or eliminate beneficial reuse options. Environmental groups and other parties have filed lawsuits in the U.S. District Court for the District of Columbia seeking to require the EPA to complete its rulemaking process and issue final regulations pertaining to the regulation of coal combustion byproducts.

While the ultimate outcome of this matter cannot be determined at this time and will depend on the final form of any rules adopted and the outcome of any legal challenges, additional regulation of coal combustion byproducts could have a material impact on the generation, management, beneficial use, and disposal of such byproducts. Any material changes are likely to result in substantial additional compliance, operational, and capital costs that could affect future unit retirement and replacement decisions. Moreover, the Company could incur additional material asset retirement obligations with respect to closing existing storage facilities. The Company's results of operations, cash flows, and financial condition could be significantly impacted if such costs are not recovered through regulated rates. Further, higher costs that are recovered through regulated rates could contribute to reduced demand for electricity, which could negatively impact results of operations, cash flows, and financial condition.

Environmental Remediation

The Company must comply with other environmental laws and regulations that cover the handling and disposal of waste and releases of hazardous substances. Under these various laws and regulations, the Company may also incur substantial costs to clean up properties. The Company conducts studies to determine the extent of any required cleanup and has recognized in its financial statements the costs to clean up known impacted sites. Amounts for cleanup and ongoing monitoring costs were not material for any year presented. The Company may be liable for some or all required cleanup costs for additional sites that may require environmental remediation. See Notes 1 and 3 to the financial statements under "Environmental Remediation Recovery" and "Environmental Matters – Environmental Remediation," respectively, for additional information.

Global Climate Issues

The EPA currently regulates greenhouse gases under the Prevention of Significant Deterioration and Title V operating permit programs of the Clean Air Act. In addition, over the past several years, the U.S. Congress has considered many proposals to reduce greenhouse gas emissions, mandate renewable or clean energy, and impose energy efficiency standards. Such proposals are expected to continue to be considered by the U.S. Congress. International climate change negotiations under the United Nations Framework Convention on Climate Change are also continuing.

On April 13, 2012, the EPA published proposed regulations to establish standards of performance for greenhouse gas emissions from new fossil fuel steam electric generating units. The EPA has also announced plans to develop federal guidelines for states to establish greenhouse gas emissions performance standards for existing sources. The impact of this rulemaking will depend on the scope and specific requirements of the final rule and the outcome of any legal challenges and, therefore, cannot be determined at this time.

Although the outcome of federal, state, and international initiatives cannot be determined at this time, additional restrictions on the Company's greenhouse gas emissions or requirements relating to renewable energy or energy efficiency at the federal or state level could result in significant additional compliance costs, including capital expenditures. These costs could affect future unit retirement and replacement decisions and could result in the retirement of additional coal-fired generating units. Also, additional compliance costs and costs related to unit retirements could affect results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates. Further, higher costs that are recovered through regulated rates could contribute to reduced demand for electricity, which could negatively impact results of operations, cash flows, and financial condition.

The EPA's greenhouse gas reporting rule requires annual reporting of carbon dioxide equivalent emissions in metric tons for a company's operational control of facilities. Based on ownership or financial control of facilities, the Company reported 2011 greenhouse gas emissions of approximately 47 million metric tons of carbon dioxide equivalent. The preliminary estimate of the Company's 2012 greenhouse gas emissions on the same basis is approximately 33 million metric tons of carbon dioxide equivalent. The level of greenhouse gas emissions from year to year will depend on the level of generation and mix of fuel sources, which is determined primarily by demand, the unit cost of fuel consumed, and the availability of generating units.

PSC Matters

Rate Plans

The economic recession significantly reduced the Company's revenues upon which retail rates were set under the 2007 Retail Rate Plan. In 2009, despite stringent efforts to reduce expenses, the Company's projected retail return on common equity (ROE) for both 2009 and 2010 was below 10.25%. However, in lieu of a full base rate case to increase customer rates as allowed under the 2007 Retail Rate Plan, in 2009, the Georgia PSC approved the Company's request for an accounting order. Under the terms of the accounting order, the Company could amortize up to $108 million of the regulatory liability related to other cost of removal obligations in 2009 and up to $216 million in 2010, limited to the amount needed to earn no more than a 9.75% and 10.15% retail ROE in 2009 and 2010, respectively. For the years ended December 31, 2009 and 2010, the Company amortized $41 million and $174 million, respectively, of the regulatory liability related to other cost of removal obligations.

In 2010, the Georgia PSC approved the 2010 ARP, which became effective January 1, 2011. The terms of the 2010 ARP reflect a settlement agreement among the Company, the Georgia PSC Public Interest Advocacy Staff, and eight other intervenors. Under the terms of the 2010 ARP, the Company is amortizing approximately $92 million of its remaining regulatory liability related to other cost of removal obligations over the three years ending December 31, 2013.

Also under the terms of the 2010 ARP, effective January 1, 2011, the Company increased its (1) traditional base tariff rates by approximately $347 million; (2) Demand-Side Management (DSM) tariff rates by approximately $31 million; (3) ECCR tariff rate by approximately $168 million; and (4) Municipal Franchise Fee (MFF) tariff rate by approximately $16 million, for a total increase in base revenues of approximately $562 million.

Under the 2010 ARP, the following additional base rate adjustments have been made to the Company's tariffs in 2012 and 2013:

- Effective January 1, 2012 and 2013, the DSM tariffs increased by $17 million and $14 million, respectively;
- Effective April 1, 2012 and January 1, 2013, the traditional base tariffs increased by an estimated $122 million and $58 million, respectively, to recover the revenue requirements for Plant McDonough-Atkinson Units 4, 5, and 6 for the period through December 31, 2013; and
- The MFF tariff increased consistently with the adjustments above, as well as those related to the interim fuel rider (IFR) and NCCR tariff adjustments described herein under "Fuel Cost Recovery" and "Nuclear Construction."

Under the 2010 ARP, the Company's allowed retail ROE is set at 11.15%, and earnings will be evaluated against a retail ROE range of 10.25% to 12.25%. Two-thirds of any earnings above 12.25% will be directly refunded to customers, with the remaining one-third retained by the Company. There were no refunds related to earnings for 2011 or 2012. The Company is required to file a general base rate case by July 1, 2013, in response to which the Georgia PSC would be expected to determine whether the 2010 ARP should be continued, modified, or discontinued.

Integrated Resource Plans

See "Environmental Matters – Environmental Statutes and Regulations – Air Quality," "– Water Quality," and "– Coal Combustion Byproducts" and "Rate Plans" herein for additional information regarding proposed and final EPA rules and regulations, including the MATS rule for coal- and oil-fired electric utility steam generating units, revisions to effluent guidelines for steam electric power plants, and additional regulation of coal combustion byproducts; the State of Georgia's Multi-Pollutant Rule; the Company's analysis of the potential costs and benefits of installing the required controls on its fossil generating units in light of these regulations; and the 2010 ARP.

On March 20, 2012, the Georgia PSC approved the Company's request to decertify and retire Plant Branch Units 1 and 2 as of December 31, 2013 and October 31, 2013, the compliance dates for the respective units under the Georgia Multi-Pollutant Rule, and an oil-fired unit at Plant Mitchell as of March 26, 2012, as requested in the 2011 IRP. The Georgia PSC also approved three PPAs totaling 998 MWs with Southern Power for capacity and energy that will commence in 2015 and end in 2030. On November 21, 2012, the FERC accepted the PPAs.

Separately, on March 20, 2012, the Georgia PSC certified 495 MWs of wholesale capacity to be returned to retail service in 2015 and 2016 under a 2010 agreement, subject to the decertification of any related generating units including 243 MWs of the 16 units described below.

Separately, on October 16, 2012, the Georgia PSC approved a 50 MW PPA with a small power production facility (80 MWs or less) that is a qualifying facility under the Public Utility Regulatory Policies Act of 1978 for capacity and energy that will commence in 2015 and end in 2035.

In addition, on November 20, 2012, the Georgia PSC approved the Company's advanced solar initiative. The Company may acquire up to 210 MWs of additional solar capacity over a three-year period through long-term contracts.

On January 31, 2013, the Company filed its triennial IRP (2013 IRP). The filing included the Company's request to decertify 16 coal- and oil-fired units totaling 2,093 MWs. Several factors, including the cost to comply with existing and future environmental regulations, recent and forecasted economic conditions, and lower natural gas prices, contributed to the decision to close these units.

The Company requested the decertification of Plant Boulevard Units 2 and 3 (28 MWs) upon approval of the 2013 IRP and the decertification of Plant Bowen Unit 6 (32 MWs) by April 16, 2013. Plant Branch Units 3 and 4 (1,016 MWs), Plant Yates Units 1 through 5 (579 MWs), and Plant McManus Units 1 and 2 (122 MWs) will be retired by April 16, 2015, the compliance date of the MATS rule. The Company has also requested a revision to the decertification date of Plant Branch Unit 1 from December 31, 2013 to April 16, 2015. To allow for necessary transmission reliability improvements, the Company expects to seek a one-year extension of the MATS rule compliance date for Plant Kraft Units 1 through 4 (316 MWs) and to retire these units by April 16, 2016.

The filing also included the Company's request to switch the primary fuel source for Plant Yates Units 6 and 7 from coal to natural gas. Additionally, the Company plans to switch the primary fuel source for Plant McIntosh Unit 1 from Central Appalachian coal to Powder River Basin (PRB) coal following further evaluation, including a successful test burn of the PRB fuel.

Under the terms of the 2010 ARP, any costs associated with changes to the Company's approved environmental operating or capital budgets resulting from new or revised environmental regulations through 2013 that are approved by the Georgia PSC in connection with an updated IRP will be deferred as a regulatory asset to be recovered over a time period deemed appropriate by the Georgia PSC. In connection with the retirement decisions, the Company reclassified the retail portion of the net carrying value of Plant Branch Units 1 through 4 from plant in service, net of depreciation, to other utility plant, net. The Company is continuing to depreciate these units using the current composite straight-line rates previously approved by the Georgia PSC. Upon actual retirement, the Georgia PSC approved the continued deferral and amortization of the remaining net carrying values for Plant Branch Units 1 and 2 in its order for the 2011 IRP and the Company has requested similar treatment for Plant Branch Units 3 and 4 in the 2013 IRP. The Company also reclassified the construction work in progress (CWIP) balances totaling $65 million related to environmental controls for Plant Branch Units 1 through 4 and Plant Yates Units 6 and 7 that will not be completed as a result of the retirement decisions to regulatory assets and ceased accruing AFUDC. The Georgia PSC approved a three-year amortization period beginning January 2014 for the $13 million balance relating to Plant Branch Units 1 and 2 in its order for the 2011 IRP and the Company has requested similar treatment for the balances related to Plant Branch Units 3 and 4 and Plant Yates Units 6 and 7 in the 2013 IRP. The Company has also requested that the Georgia PSC approve the deferral of the costs associated with material and supplies remaining at the unit retirement dates to a regulatory asset, to be amortized over a time period deemed appropriate by the Georgia PSC. As a result of this regulatory treatment, the decertification of these units is not expected to have a material impact on the Company's financial statements. The Georgia PSC is scheduled to vote on the 2013 IRP by July 2013.

Fuel Cost Recovery

The Company has established fuel cost recovery rates approved by the Georgia PSC. The Georgia PSC approved reductions in the Company's total annual billings of approximately $43 million effective June 1, 2011, $567 million effective June 1, 2012, and $122 million effective January 1, 2013. In addition, the Georgia PSC has authorized an IFR, which allows the Company to adjust its fuel cost recovery rates prior to the next fuel case if the under or over recovered fuel balance exceeds $215 million through February 2013 and $200 million thereafter. The Company's fuel cost recovery includes costs associated with a natural gas hedging program as revised and approved by the Georgia PSC on February 7, 2013. See FINANCIAL CONDITION AND LIQUIDITY – "Market Price Risk" herein and Note 10 to the financial statements under "Energy-Related Derivatives" for additional information. The Company expects to file its next fuel case by March 1, 2014.

The Company's over recovered fuel balance totaled approximately $230 million at December 31, 2012 and is included in current liabilities and other deferred credits and liabilities.

Fuel cost recovery revenues as recorded on the financial statements are adjusted for differences in actual recoverable fuel costs and amounts billed in current regulated rates. Accordingly, changes in the billing factor will not have a significant effect on the Company's revenues or net income, but will affect cash flow. See Note 3 to the financial statements under "Retail Regulatory Matters – Fuel Cost Recovery" for additional information.

Storm Damage Recovery

The Company defers and recovers certain costs related to damages from major storms as mandated by the Georgia PSC. As of December 31, 2012, the balance in the regulatory asset related to storm damage was $38 million. As a result of this regulatory treatment, the costs related to storms are generally not expected to have a material impact on the Company's financial statements. See Note 1 to the financial statements under "Storm Damage Recovery" for additional information.

Nuclear Construction

In 2008, the Company, acting for itself and as agent for Oglethorpe Power Corporation (OPC), the Municipal Electric Authority of Georgia (MEAG Power), and the City of Dalton, Georgia (Dalton), acting by and through its Board of Water, Light, and Sinking Fund Commissioners (collectively, Owners), entered into an agreement with a consortium consisting of Westinghouse Electric Company LLC (Westinghouse) and Stone & Webster, Inc. (collectively, Contractor), pursuant to which the Contractor agreed to design, engineer, procure, construct, and test two AP1000 nuclear units (with electric generating capacity of approximately 1,100 MWs each) and related facilities at Plant Vogtle (Vogtle 3 and 4 Agreement). Under the terms of the Vogtle 3 and 4 Agreement, the Owners agreed to pay a purchase price that is subject to certain price escalations and adjustments, including fixed escalation amounts and index-based adjustments, as well as adjustments for change orders, and performance bonuses for early completion and unit performance. Each Owner is severally (and not jointly) liable for its proportionate share, based on its ownership interest, of all amounts owed to the Contractor under the Vogtle 3 and 4 Agreement. The Company's proportionate share is 45.7%. The Vogtle 3 and 4 Agreement provides for liquidated damages upon the Contractor's failure to fulfill the schedule and performance guarantees. The Contractor's liability to the Owners for schedule and performance liquidated damages and warranty claims is subject to a cap.

Certain payment obligations of Westinghouse and Stone & Webster, Inc. under the Vogtle 3 and 4 Agreement are guaranteed by Toshiba Corporation and The Shaw Group, Inc., respectively. In the event of certain credit rating downgrades of any Owner, such Owner will be required to provide a letter of credit or other credit enhancement. The Owners may terminate the Vogtle 3 and 4 Agreement at any time for their convenience, provided that the Owners will be required to pay certain termination costs and, at certain stages of the work, cancellation fees to the Contractor. The Contractor may terminate the Vogtle 3 and 4 Agreement under certain circumstances, including certain Owner suspension or delays of work, action by a governmental authority to permanently stop work, certain breaches of the Vogtle 3 and 4 Agreement by the Owners, Owner insolvency, and certain other events.

In 2009, the Georgia PSC originally certified construction costs of $6.4 billion to place Plant Vogtle Units 3 and 4 into service in April 2016 and April 2017, respectively, and approved inclusion of the related CWIP accounts in rate base. Also in 2009, the State of Georgia enacted the Georgia Nuclear Energy Financing Act, which allows the Company to recover financing costs for nuclear construction projects through annual adjustments to an NCCR tariff by including the related CWIP accounts in rate base during the construction period. With respect to Plant Vogtle Units 3 and 4, this legislation allowed the Company, beginning in 2011, to recover an estimated $1.7 billion of related financing costs during the construction period. As a result, in 2009, the Georgia PSC also revised the certified in-service capital cost to approximately $4.4 billion.

The Georgia PSC approved increases to the NCCR tariff of approximately $223 million, $35 million, and $50 million, effective January 1, 2011, 2012, and 2013, respectively. Through the NCCR tariff, the Company is collecting and amortizing to earnings approximately $91 million of financing costs, capitalized in 2009 and 2010, over the five-year period ending December 31, 2015, in addition to the ongoing financing costs. At December 31, 2012, approximately $55 million of these 2009 and 2010 costs remained unamortized in CWIP. At December 31, 2012, the Company's CWIP balance for Plant Vogtle Units 3 and 4 totaled $2.3 billion.

In 2009, the Nuclear Regulatory Commission (NRC) issued an Early Site Permit and Limited Work Authorization which allowed limited work to begin on Plant Vogtle Units 3 and 4. The NRC certified the Westinghouse Design Control Document, as amended (DCD), for the AP1000 nuclear reactor design, effective December 30, 2011, and issued combined construction and operating licenses (COLs) on February 10, 2012. Receipt of the COLs allowed full construction to begin.

On February 16, 2012, separate groups of petitioners filed petitions in the U.S. Court of Appeals for the District of Columbia Circuit seeking judicial review of the NRC's issuance of the COLs and certification of the DCD. These petitions were consolidated on April 3, 2012. On April 18, 2012, another group of petitioners filed a motion to stay the effectiveness of the COLs with the U.S. District Court for the District of Columbia. On July 11, 2012, the U.S. Court of Appeals for the District of Columbia Circuit denied the petitioners' motion to stay the effectiveness of the COLs. The Company has intervened in, and

intends to vigorously contest, these petitions. Additional technical and procedural challenges to the construction and licensing of Plant Vogtle Units 3 and 4, at the federal and state level, are expected as construction proceeds.

The Company is required to file semi-annual Vogtle Construction Monitoring (VCM) reports with the Georgia PSC by February 28 and August 31 each year. On February 19, 2013, the Georgia PSC voted to approve the Company's seventh VCM report, including construction capital costs incurred through June 30, 2012 of approximately $2.0 billion. The Company's eighth VCM report requests approval for an additional $0.2 billion of construction capital costs incurred through December 31, 2012. If the projected certified construction capital costs to be borne by the Company increase by 5% or the projected in-service dates are significantly extended, the Company is required to seek an amendment to the Plant Vogtle Units 3 and 4 certificate from the Georgia PSC. Accordingly, the eighth VCM also requests an amendment to the certificate to increase the estimated in-service capital cost of Plant Vogtle Units 3 and 4 to $4.8 billion and to extend the estimated in-service dates to fourth quarter 2017 and fourth quarter 2018 for Plant Vogtle Units 3 and 4, respectively. Associated financing costs during the construction period are estimated to total approximately $2.0 billion.

In July 2012, the Owners and the Contractor began negotiations regarding the costs associated with design changes to the DCD and the delays in the timing of approval of the DCD and issuance of the COLs, including the assertion by the Contractor that the Owners are responsible for these costs under the terms of the Vogtle 3 and 4 Agreement. The Contractor has claimed that its estimated adjustment attributable to the Company (based on the Company's ownership interest) is approximately $425 million (in 2008 dollars) with respect to these issues. The Contractor also has asserted it is entitled to further schedule extensions. The Company has not agreed with either the proposed cost or schedule adjustments or that the Owners have any responsibility for costs related to these issues. On November 1, 2012, the Company and the other Owners filed suit against the Contractor in the U.S. District Court for the Southern District of Georgia seeking a declaratory judgment that the Owners are not responsible for these costs. Also on November 1, 2012, the Contractor filed suit against the Company and the other Owners in the U.S. District Court for the District of Columbia alleging the Owners are responsible for these costs. While litigation has commenced and the Company intends to vigorously defend its positions, the Company expects negotiations with the Contractor to continue with respect to cost and schedule during which negotiations the parties may reach a mutually acceptable compromise of their positions.

In addition, there are processes in place that are designed to assure compliance with the requirements specified in the DCD and the COLs, including rigorous inspections by Southern Nuclear and the NRC that occur throughout construction. During the fourth quarter 2012, certain details of the rebar design for the Plant Vogtle Unit 3 nuclear island were evaluated for consistency with the DCD and a few non-safety-related deviations were identified. On January 15, 2013 and January 18, 2013, Southern Nuclear submitted two license amendment requests to conform the rebar design details to NRC requirements. On January 29, 2013, the NRC issued "no objection" letters in response to the related preliminary amendment requests, enabling completion of final work supporting the pouring of base mat concrete, which is expected to occur following approval of the license amendment requests in March 2013. Various design and other issues are expected to arise as construction proceeds, which may result in additional license amendments or require other resolution. If any license amendment requests are not resolved in a timely manner, there may be delays in the project schedule that could result in increased costs either to the Owners, the Contractor, or both.

As construction continues, additional delays in the fabrication and assembly of structural modules, the failure of such modules to meet applicable standards, or other issues may further impact project schedule and cost. Additional claims by the Contractor or the Company (on behalf of the Owners) are also likely to arise throughout construction. These claims may be resolved through formal and informal dispute resolution procedures under the Vogtle 3 and 4 Agreement, but also may be resolved through litigation.

The ultimate outcome of these matters cannot be determined at this time.

Income Tax Matters

Bonus Depreciation

In 2010, the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010 (Tax Relief Act) was signed into law. Major tax incentives in the Tax Relief Act include 100% bonus depreciation for property placed in service after September 8, 2010 and through 2011 (and for certain long-term production-period projects placed in service in 2012) and 50% bonus depreciation for property placed in service in 2012 (and for certain long-term production-period projects to be placed in service in 2013), which will have a positive impact on the Company's 2013 cash flows.

On January 2, 2013, the American Taxpayer Relief Act of 2012 (ATRA) was signed into law. The ATRA retroactively extended several tax credits through 2013 and extended 50% bonus depreciation for property to be placed in service in 2013 (and for certain long-term production-period projects to be placed in service in 2014). The extension of 50% bonus depreciation will have a positive impact on the future cash flows of the Company through 2014.

Consequently, the Company's positive cash flow benefit is estimated to be between $170 million and $190 million in 2013.

Other Matters

The Company is involved in various other matters being litigated and regulatory matters that could affect future earnings. In addition, the Company is subject to certain claims and legal actions arising in the ordinary course of business. The Company's business activities are subject to extensive governmental regulation related to public health and the environment, such as regulation of air emissions and water discharges. Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements such as air quality and water standards, has increased generally throughout the U.S. In particular, personal injury, property damage, and other claims for damages alleged to have been caused by carbon dioxide and other emissions, coal combustion byproducts, and alleged exposure to hazardous materials, and/or requests for injunctive relief in connection with such matters, have become more frequent.

The ultimate outcome of such pending or potential litigation against the Company cannot be predicted at this time; however, for current proceedings not specifically reported herein or in Note 3 to the financial statements, management does not anticipate that the ultimate liabilities, if any, arising from such current proceedings would have a material effect on the Company's financial statements. See Note 3 to the financial statements for a discussion of various other contingencies, regulatory matters, and other matters being litigated which may affect future earnings potential.

In March 2011, a major earthquake and tsunami struck Japan and caused substantial damage to the nuclear generating units at the Fukushima Daiichi generating plant. The events in Japan have created uncertainties that may affect future costs for operating nuclear plants. Specifically, the NRC is performing additional operational and safety reviews of nuclear facilities in the U.S., which could potentially impact future operations and capital requirements. On March 12, 2012, the NRC issued three orders and a request for information based on the July 2011 NRC task force report recommendations that included, among other items, additional mitigation strategies for beyond-design-basis events, enhanced spent fuel pool instrumentation capabilities, hardened vents for certain classes of containment structures, including the one in use at Plant Hatch, site specific evaluations for seismic and flooding hazards, and various plant evaluations to ensure adequate coping capabilities during station blackout and other conditions. On August 29, 2012, the NRC staff issued the final interim staff guidance document, which offers acceptable approaches to meeting the requirements of the NRC's orders before the December 31, 2016 compliance deadline. The interim staff guidance is not mandatory, but licensees would be required to obtain NRC approval for taking an approach other than as outlined in the interim staff guidance. The final form and the resulting impact of any changes to safety requirements for nuclear reactors will be dependent on further review and action by the NRC and cannot be determined at this time; however, management does not currently anticipate that the associated compliance costs would have a material impact on the Company's financial statements.

ACCOUNTING POLICIES

Application of Critical Accounting Policies and Estimates

The Company prepares its financial statements in accordance with generally accepted accounting principles (GAAP). Significant accounting policies are described in Note 1 to the financial statements. In the application of these policies, certain estimates are made that may have a material impact on the Company's results of operations and related disclosures. Different assumptions and measurements could produce estimates that are significantly different from those recorded in the financial statements. Senior management has reviewed and discussed the following critical accounting policies and estimates with the Audit Committee of Southern Company's Board of Directors.

Electric Utility Regulation

The Company is subject to retail regulation by the Georgia PSC and wholesale regulation by the FERC. These regulatory agencies set the rates the Company is permitted to charge customers based on allowable costs. As a result, the Company applies accounting standards which require the financial statements to reflect the effects of rate regulation. Through the ratemaking process, the regulators may require the inclusion of costs or revenues in periods different than when they would be recognized by a non-regulated company. This treatment may result in the deferral of expenses and the recording of related regulatory assets based on anticipated future recovery through rates or the deferral of gains or creation of liabilities and the recording of related regulatory liabilities. The application of the accounting standards has a further effect on the Company's financial statements as a result of the estimates of allowable costs used in the ratemaking process. These estimates may differ from those actually incurred by the Company; therefore, the accounting estimates inherent in specific costs such as depreciation, nuclear decommissioning, and pension and postretirement benefits have less of a direct impact on the Company's results of operations and financial condition than they would on a non-regulated company.

As reflected in Note 1 to the financial statements, significant regulatory assets and liabilities have been recorded. Management reviews the ultimate recoverability of these regulatory assets and any requirement to refund these regulatory liabilities based on applicable regulatory guidelines and GAAP. However, adverse legislative, judicial, or regulatory actions could materially impact the amounts of such regulatory assets and liabilities and could adversely impact the Company's financial statements.

Contingent Obligations

The Company is subject to a number of federal and state laws and regulations, as well as other factors and conditions that subject it to environmental, litigation, income tax, and other risks. See FUTURE EARNINGS POTENTIAL herein and Note 3 to the financial statements for more information regarding certain of these contingencies. The Company periodically evaluates its exposure to such risks and, in accordance with GAAP, records reserves for those matters where a non-tax-related loss is considered probable and reasonably estimable and records a tax asset or liability if it is more likely than not that a tax position will be sustained. The adequacy of reserves can be significantly affected by external events or conditions that can be unpredictable; thus, the ultimate outcome of such matters could materially affect the Company's financial statements.

Pension and Other Postretirement Benefits

The Company's calculation of pension and other postretirement benefits expense is dependent on a number of assumptions. These assumptions include discount rates, healthcare cost trend rates, expected long-term return on plan assets, mortality rates, expected salary and wage increases, and other factors. Components of pension and other postretirement benefits expense include interest and service cost on the pension and other postretirement benefit plans, expected return on plan assets, and amortization of certain unrecognized costs and obligations. Actual results that differ from the assumptions utilized are accumulated and amortized over future periods and, therefore, generally affect recognized expense and the recorded obligation in future periods. While the Company believes that the assumptions used are appropriate, differences in actual experience or significant changes in assumptions would affect its pension and other postretirement benefits costs and obligations.

Key elements in determining the Company's pension and other postretirement benefit expense in accordance with GAAP are the expected long-term return on plan assets and the discount rate used to measure the benefit plan obligations and the periodic benefit plan expense for future periods. The expected long-term return on postretirement benefit plan assets is based on the Company's investment strategy, historical experience, and expectations for long-term rates of return that consider external actuarial advice. The Company determines the long-term return on plan assets by applying the long-term rate of expected returns on various asset classes to the Company's target asset allocation. The Company discounts the future cash flows related to its postretirement benefit plans using a single-point discount rate developed from the weighted average of market-observed yields for high quality fixed income securities with maturities that correspond to expected benefit payments.

A 25 basis point change in any significant assumption (discount rate, salaries, or long-term return on plan assets) would result in a $14 million or less change in total annual benefit expense and a $175 million or less change in projected obligations.

FINANCIAL CONDITION AND LIQUIDITY

Overview

The Company's financial condition remained stable at December 31, 2012. The Company's cash requirements primarily consist of funding ongoing operations, common stock dividends, capital expenditures, and debt maturities. Capital expenditures and other investing activities include investments to meet projected long-term demand requirements, to comply with environmental regulations, and for restoration following major storms. Operating cash flows provide a substantial portion of the Company's cash needs. For the three-year period from 2013 through 2015, the Company's projected common stock dividends, capital expenditures, and debt maturities are expected to exceed operating cash flows. Projected capital expenditures in that period include investments to build new generation facilities, to add environmental equipment for existing generating units, and to expand and improve transmission and distribution facilities. The Company plans to finance future cash needs in excess of its operating cash flows primarily through debt and equity issuances. The Company intends to continue to monitor its access to short-term and long-term capital markets as well as its bank credit arrangements to meet future capital and liquidity needs. See "Sources of Capital," "Financing Activities," and "Capital Requirements and Contractual Obligations" herein for additional information.

The Company's investments in the qualified pension plan and the nuclear decommissioning trust funds increased in value as of December 31, 2012 as compared to December 31, 2011. No contributions to the qualified pension plan were made in 2012. The Company funded approximately $2 million to its nuclear decommissioning trust funds in 2012.

Net cash provided from operating activities totaled $2.3 billion in 2012, a decrease of $337 million from 2011, primarily due to higher fuel inventory additions in 2012 and lower deferred taxes due to the effect of bonus depreciation in 2011, partially offset by higher recovery of retail fuel costs. Net cash provided from operating activities totaled $2.6 billion in 2011, an increase of $785 million from 2010, primarily due to higher retail operating revenues, increased deferred income taxes in 2011 primarily due to bonus depreciation, and contributions to the qualified pension plan in 2010.

Net cash used for investing activities totaled $2.0 billion, $1.8 billion, and $2.2 billion in 2012, 2011, and 2010, respectively, due to gross property additions primarily related to installation of equipment to comply with environmental standards; construction of generation, transmission, and distribution facilities; and purchase of nuclear fuel. The majority of funds needed for gross property additions for the last several years has been provided from operating activities, capital contributions from Southern Company, and the issuance of debt.

Net cash (used for)/provided from financing activities totaled $(290) million, $(836) million, and $391 million for 2012, 2011, and 2010, respectively. The decrease in cash used in 2012 compared to 2011 was primarily due to additional debt issuances in 2012 to support the ongoing construction program. The increase in cash used in 2011 compared to 2010 was primarily a reflection of lower capital contributions from Southern Company, higher common stock dividends paid to Southern Company, and lower debt issuances due to the availability of more internally generated cash in 2011. See "Financing Activities" herein for additional information. Fluctuations in cash flow from financing activities vary from year to year based on capital needs and the maturity or redemption of securities.

Significant balance sheet changes in 2012 include increases of $1.2 billion in total property, plant, and equipment and $688 million in debt, as well as a $367 million change in under/over recovered fuel.

The Company's ratio of common equity to total capitalization, including short-term debt, was 48.3% in 2012 and 49.4% in 2011. See Note 6 to the financial statements for additional information.

Sources of Capital

Except as described below with respect to potential U.S. Department of Energy (DOE) loan guarantees, the Company plans to obtain the funds required for construction and other purposes from sources similar to those used in the past, which were primarily from operating cash flows, short-term debt, security issuances, term loans, and equity contributions from Southern Company. However, the amount, type, and timing of any future financings, if needed, will depend upon regulatory approvals, prevailing market conditions, and other factors.

In 2010, the Company reached an agreement with the DOE to accept terms for a conditional commitment for federal loan guarantees that would apply to future borrowings by the Company related to the construction of Plant Vogtle Units 3 and 4. Any borrowings guaranteed by the DOE would be full recourse to the Company and secured by a first priority lien on the Company's 45.7% undivided ownership interest in Plant Vogtle Units 3 and 4. Total guaranteed borrowings would not exceed the lesser of 70% of eligible project costs, or approximately $3.46 billion, and are expected to be funded by the Federal Financing Bank. Final approval and issuance of loan guarantees by the DOE are subject to negotiation of definitive agreements, completion of due diligence by the DOE, receipt of any necessary regulatory approvals, and satisfaction of other conditions. In the event that the DOE does not issue a loan guarantee or the Company determines that the final terms and conditions of the loan guarantee by the DOE are not in the best interest of its customers, the Company expects to finance the construction of Plant Vogtle Units 3 and 4 through traditional capital markets financings. There can be no assurance that the DOE will issue loan guarantees for the Company. The conditional commitment will expire on June 30, 2013, unless further extended by the DOE. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Nuclear Construction" herein and Note 3 to the financial statements under "Retail Regulatory Matters – Nuclear Construction" for more information on Plant Vogtle Units 3 and 4.

The issuance of long-term securities by the Company is subject to the approval of the Georgia PSC. In addition, the issuance of short-term debt securities by the Company is subject to regulatory approval by the FERC. Additionally, with respect to the public offering of securities, the Company files registration statements with the Securities and Exchange Commission (SEC) under the Securities Act of 1933, as amended. The amounts of securities authorized by the Georgia PSC and the FERC are continuously monitored and appropriate filings are made to ensure flexibility in the capital markets.

The Company obtains financing separately without credit support from any affiliate. See Note 6 to the financial statements under "Bank Credit Arrangements" for additional information. The Southern Company system does not maintain a centralized cash or money pool. Therefore, funds of the Company are not commingled with funds of any other company in the Southern Company system.

The Company's current liabilities frequently exceed current assets because of the continued use of short-term debt as a funding source to meet scheduled maturities of long-term debt, as well as cash needs, which can fluctuate significantly due to the seasonality of the Company's business. The Company has substantial cash flow from operating activities and access to the capital markets to meet liquidity needs. At December 31, 2012, the Company had approximately $45 million of cash and cash equivalents. Committed credit arrangements with banks at December 31, 2012 were as follows:

Expires[a]			
2014	2016	Total	Unused
		(in millions)	
$250	$1,500	$1,750	$1,740

(a) No credit arrangements expire in 2013 or 2015.

See Note 6 to the financial statements under "Bank Credit Arrangements" for additional information. These arrangements contain covenants that limit debt levels and contain cross default provisions that are restricted only to the indebtedness of the Company. The Company is currently in compliance with all such covenants. The Company expects to renew its credit arrangements, as needed, prior to expiration.

These credit arrangements provide liquidity support to the Company's variable rate pollution control revenue bonds and commercial paper borrowings. The amount of variable rate pollution control revenue bonds outstanding requiring liquidity support as of December 31, 2012 was approximately $865 million.

The Company may also meet short-term cash needs through a Southern Company subsidiary organized to issue and sell commercial paper at the request and for the benefit of the Company and the other traditional operating companies. Proceeds from such issuances for the benefit of the Company are loaned directly to the Company. The obligations of each company under these arrangements are several and there is no cross affiliate credit support.

Details of short-term borrowings were as follows:

	Short-term Debt at the End of the Period[a]		Short-term Debt During the Period [b]		
	Amount Outstanding	Weighted Average Interest Rate	Average Outstanding	Weighted Average Interest Rate	Maximum Amount Outstanding
	(in millions)		*(in millions)*		*(in millions)*
December 31, 2012:					
Commercial paper	$ —	—%	$ 78	0.2%	$ 517
Short-term bank debt	—	—%	116	1.2%	300
Total	$ —	—%	$ 194	0.8%	
December 31, 2011:					
Commercial paper	$ 313	0.2%	$ 208	0.3%	$ 681
Short-term bank debt	200	1.2%	9	1.2%	200
Total	$ 513	0.5%	$ 217	0.3%	
December 31, 2010:					
Commercial paper	$ 575	0.3%	$ 167	0.3%	$ 575

(a) Excludes notes payable related to other energy service contracts of $2 million in 2012 and 2011 and $1 million in 2010.
(b) Average and maximum amounts are based upon daily balances during the twelve-month periods ended December 31, 2012, 2011, and 2010.

Management believes that the need for working capital can be adequately met by utilizing commercial paper programs, lines of credit, and cash.

Financing Activities

In addition to any financings that may be necessary to meet capital requirements and contractual obligations, the Company plans to continue, when economically feasible, a program to retire higher-cost securities and replace these obligations with lower-cost capital if market conditions permit.

Pollution Control Revenue Bonds

In May 2012, the Development Authority of Monroe County issued $48.72 million aggregate principal amount of Pollution Control Revenue Bonds (Georgia Power Company Plant Scherer Project), First Series 2012 for the benefit of the Company. The proceeds were used in June 2012 to redeem $48.72 million aggregate principal amount of Development Authority of Monroe County Pollution Control Revenue Bonds (Georgia Power Company Plant Scherer Project), First Series 2006.

In June 2012, the Development Authority of Burke County issued $85 million aggregate principal amount of Pollution Control Revenue Bonds (Georgia Power Company Plant Vogtle Project), First Series 2012 and $100 million aggregate principal amount of Pollution Control Revenue Bonds (Georgia Power Company Plant Vogtle Project), Second Series 2012 for the benefit of the Company. The proceeds were used in July 2012 to redeem $85 million aggregate principal amount of Development Authority of Burke County (Georgia) Pollution Control Revenue Bonds (Georgia Power Company Plant Vogtle Project), First Series 2005 and $100 million aggregate principal amount of Development Authority of Burke County (Georgia) Pollution Control Revenue Bonds (Georgia Power Company Plant Vogtle Project), Second Series 2005.

In November 2012, the Development Authority of Burke County issued $50 million aggregate principal amount of Pollution Control Revenue Bonds (Georgia Power Company Plant Vogtle Project), Third Series 2012 for the benefit of the Company. The proceeds were used in December 2012 to redeem $50 million aggregate principal amount of Development Authority of Burke County (Georgia) Pollution Control Revenue Bonds (Georgia Power Company Plant Vogtle Project), Second Series 1997.

Senior Notes

In March 2012 and May 2012, the Company issued $750 million and $350 million, respectively, aggregate principal amount of Series 2012A 4.30% Senior Notes due March 15, 2042. Also in May 2012, the Company issued $400 million aggregate principal amount of Series 2012B 2.85% Senior Notes due May 15, 2022. In August 2012, the Company issued $400 million aggregate principal amount of Series 2012C 0.75% Senior Notes due August 10, 2015. The net proceeds from these issuances were used to repay a portion of the Company's short-term debt and the bank loans described below under "Other," for the redemption in July 2012 of $300 million aggregate principal amount of the Company's Series 2007D 6.375% Senior Notes due June 15, 2047, the redemption in September 2012 of $250 million aggregate principal amount of the Company's Series 2007E 6.00% Senior Insured Monthly Notes due September 1, 2040, and for general corporate purposes, including the Company's continuous construction program.

In November 2012, the Company's $200 million aggregate principal amount of Series K 5.125% Senior Monthly Notes due November 15, 2012 matured. Also in November 2012, the Company issued $400 million aggregate principal amount of Series 2012D 0.625% Senior Notes due November 15, 2015. The proceeds were used to redeem $100 million aggregate principal amount of the Company's Series 2007F 6.05% Senior Monthly Notes due December 1, 2038, and for general corporate purposes, including the Company's continuous construction program.

Other

In January 2012, the Company entered into a six-month floating rate bank loan in an aggregate amount of $100 million, bearing interest based on one-month London Interbank Offered Rate (LIBOR). The proceeds were used for general corporate purposes, including the Company's continuous construction program. This bank loan was repaid on June 11, 2012.

In March 2012, the Company repaid at maturity two bank loans, each in an aggregate principal amount of $125 million, each bearing interest at a floating rate based on one-month LIBOR.

Credit Rating Risk

The Company does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. There are certain contracts that could require collateral, but not accelerated payment, in the event of a credit rating change to BBB- and/or Baa3 or below. These contracts are for physical electricity purchases and sales, fuel purchases, fuel transportation and storage, energy price risk management, and construction of new generation. The maximum potential collateral requirements under these contracts at December 31, 2012 were as follows:

Credit Ratings	Maximum Potential Collateral Requirements
	(in millions)
At BBB- and/or Baa3	$ 65
Below BBB- and/or Baa3	1,284

Included in these amounts are certain agreements that could require collateral in the event that one or more Southern Company system power pool participants has a credit rating change to below investment grade. Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. Additionally, any credit rating downgrade could impact the Company's ability to access capital markets, particularly the short-term debt market and the variable rate pollution control revenue bond market.

Market Price Risk

Due to cost-based rate regulation and other various cost recovery mechanisms, the Company continues to have limited exposure to market volatility in interest rates, commodity fuel prices, and prices of electricity. To manage the volatility attributable to these exposures, the Company nets the exposures, where possible, to take advantage of natural offsets and enters into various derivative transactions for the remaining exposures pursuant to the Company's policies in areas such as counterparty exposure and risk management practices. The Company's policy is that derivatives are to be used primarily for hedging purposes and mandates strict adherence to all applicable risk management policies. Derivative positions are monitored using techniques including, but not limited to, market valuation, value at risk, stress testing, and sensitivity analysis.

To mitigate future exposure to changes in interest rates, the Company may enter into derivatives designated as hedges. The weighted average interest rate on $1.5 billion of outstanding variable rate long-term debt at January 1, 2013 was 0.36%. If the Company sustained a 100 basis point change in interest rates for all unhedged variable rate long-term debt , the change would affect annualized interest expense by approximately $15 million at January 1, 2013. See Note 1 to the financial statements under "Financial Instruments" and Note 11 to the financial statements for additional information.

To mitigate residual risks relative to movements in electricity prices, the Company enters into physical fixed-price contracts for the purchase and sale of electricity through the wholesale electricity market and, to a lesser extent, financial hedge contracts for natural gas purchases. The Company continues to manage a fuel hedging program implemented per the guidelines of the Georgia PSC. The Company had no material change in market risk exposure for the year ended December 31, 2012 when compared to the December 31, 2011 reporting period.

The changes in fair value of energy-related derivative contracts, substantially all of which are composed of regulatory hedges, for the years ended December 31 were as follows:

	2012 Changes	2011 Changes
	Fair Value	
	(in millions)	
Contracts outstanding at the beginning of the period, assets (liabilities), net	$ (82)	$ (100)
Contracts realized or settled	71	92
Current period changes[a]	(23)	(74)
Contracts outstanding at the end of the period, assets (liabilities), net	$ (34)	$ (82)

(a) Current period changes also include the changes in fair value of new contracts entered into during the period, if any.

The changes in the fair value positions of the energy-related derivative contracts, which are substantially all attributable to both the volume and the price of natural gas, for the years ended December 31 were as follows:

	2012 Changes	2011 Changes
	Fair Value	
	(in millions)	
Natural gas swaps	$ 44	$ 18
Natural gas options	4	—
Other energy-related derivatives	—	—
Total changes	$ 48	$ 18

The net hedge volumes of energy-related derivative contracts for the years ended December 31 were as follows:

	2012	2011
	mmBtu* Volume	
	(in millions)	
Commodity – Natural gas swaps	12	29
Commodity – Natural gas options	93	44
Total hedge volume	105	73

*million British thermal units (mmBtu)

The weighted average swap contract cost above market prices was approximately $1.09 per mmBtu as of December 31, 2012 and $1.65 per mmBtu as of December 31, 2011. The change in option fair value is primarily attributable to the volatility of the market and the underlying change in the natural gas price. All natural gas hedge gains and losses are recovered through the Company's fuel cost recovery mechanism.

At December 31, 2012 and 2011, substantially all of the Company's energy-related derivative contracts were designated as regulatory hedges and are related to the Company's fuel hedging program, which has a 48-month time horizon. The Georgia PSC recently approved changes to the Company's hedging program requiring it to use options and hedges within a 24-month time horizon. Therefore, gains and losses are initially recorded as regulatory liabilities and assets, respectively, and then are included in fuel expense as they are recovered through the fuel cost recovery mechanism. Gains and losses on energy-related derivative contracts that are not designated or fail to qualify as hedges are recognized in the statements of income as incurred and were not material for any year presented.

The Company uses over-the-counter contracts that are not exchange traded but are fair valued using prices which are market observable, and thus fall into Level 2. See Note 10 to the financial statements for further discussion of fair value measurements. The maturities of the energy-related derivative contracts, which are all Level 2 of the fair value hierarchy, at December 31, 2012 were as follows:

	Fair Value Measurements December 31, 2012		
	Total	Maturity	
	Fair Value	Year 1	Years 2&3
	(in millions)		
Level 1	$ —	$ —	$ —
Level 2	(34)	(24)	(10)
Level 3	—	—	—
Fair value of contracts outstanding at end of period	$ (34)	$ (24)	$ (10)

The Company is exposed to market price risk in the event of nonperformance by counterparties to the energy-related and interest rate derivative contracts. The Company only enters into agreements and material transactions with counterparties that have investment grade credit ratings by Moody's Investors Service, Inc. and Standard & Poor's Ratings Services, a division of The

McGraw Hill Companies, Inc., or with counterparties who have posted collateral to cover potential credit exposure. Therefore, the Company does not anticipate market risk exposure from nonperformance by the counterparties. For additional information, see Note 1 to the financial statements under "Financial Instruments" and Note 11 to the financial statements.

Capital Requirements and Contractual Obligations

The construction program of the Company is currently estimated to be $2.2 billion for 2013, $2.4 billion for 2014, and $2.2 billion for 2015. Capital expenditures to comply with existing environmental statutes and regulations included in these estimated amounts are $476 million, $441 million, and $392 million for 2013, 2014, and 2015, respectively. These amounts include capital expenditures related to contractual purchase commitments for nuclear fuel and capital expenditures covered under long-term service agreements, as well as capital expenditures and compliance costs associated with the MATS rule.

See FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations" for additional information.

The construction program is subject to periodic review and revision, and actual construction costs may vary from these estimates because of numerous factors. These factors include: changes in business conditions; changes in load projections; changes in environmental statutes and regulations; the outcome of any legal challenges to the environmental rules; changes in generating plants, including unit retirements and replacements and adding or changing fuel sources at existing units, to meet regulatory requirements; changes in FERC rules and regulations; Georgia PSC approvals; changes in the expected environmental compliance program; changes in legislation; the cost and efficiency of construction labor, equipment, and materials; project scope and design changes; storm impacts; and the cost of capital. In addition, there can be no assurance that costs related to capital expenditures will be fully recovered. See Note 3 to the financial statements under "Retail Regulatory Matters – Nuclear Construction" for additional information.

As a result of requirements by the NRC, the Company has established external trust funds for nuclear decommissioning costs. For additional information, see Note 1 to the financial statements under "Nuclear Decommissioning."

In addition, as discussed in Note 2 to the financial statements, the Company provides postretirement benefits to substantially all employees and funds trusts to the extent required by the Georgia PSC and the FERC.

Other funding requirements related to obligations associated with scheduled maturities of long-term debt, as well as the related interest, derivative obligations, preferred and preference stock dividends, leases, and other purchase commitments are detailed in the contractual obligations table that follows. See Notes 1, 2, 5, 6, 7, and 11 to the financial statements for additional information.

Contractual Obligations

	2013	2014-2015	2016-2017	After 2017	Uncertain Timing[d]	Total
			(in millions)			
Long-term debt[a] —						
Principal	$ 1,675	$ 1,050	$ 704	$ 6,205	$ —	$ 9,634
Interest	338	593	547	4,389	—	5,867
Preferred and preference stock dividends[b]	17	35	35	—	—	87
Financial derivative obligations[c]	30	14	1	—	—	45
Operating leases[d]	30	41	16	3	—	90
Capital leases[d]	5	11	13	21	—	50
Unrecognized tax benefits[e]	—	—	—	—	23	23
Purchase commitments —						
Capital[f]	1,980	4,119	—	—	—	6,099
Fuel[g]	1,967	2,456	1,253	2,123	—	7,799
Purchased power	240	549	627	2,886	—	4,302
Other[h]	52	172	55	452	—	731
Trusts —						
Nuclear decommissioning[i]	2	4	4	31	—	41
Pension and other postretirement benefit plans[j]	40	70	—	—	—	110
Total	$ 6,376	$ 9,114	$ 3,255	$ 16,110	$ 23	$ 34,878

(a) All amounts are reflected based on final maturity dates. The Company plans to continue to retire higher-cost securities and replace these obligations with lower-cost capital if market conditions permit. Variable rate interest obligations are estimated based on rates as of January 1, 2013, as reflected in the statements of capitalization. Fixed rates include, where applicable, the effects of interest rate derivatives employed to manage interest rate risk. Long-term debt excludes capital lease amounts (shown separately).

(b) Preferred and preference stock do not mature; therefore, amounts provided are for the next five years only.

(c) For additional information, see Notes 1 and 11 to the financial statements.

(d) Excludes PPAs that are accounted for as leases and are included in purchased power.

(e) The timing related to the realization of $23 million in unrecognized tax benefits cannot be reasonably and reliably estimated due to uncertainties in the timing of the effective settlement of tax positions. See Note 5 to the financial statements under "Unrecognized Tax Benefits" for additional information.

(f) The Company provides estimated capital expenditures for a three-year period, including capital expenditures and compliance costs associated with existing environmental regulations, including the MATS rule. These amounts exclude contractual purchase commitments for nuclear fuel and capital expenditures covered under long-term service agreements which are reflected separately. At December 31, 2012, significant purchase commitments were outstanding in connection with the construction program. See FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations" herein for additional information.

(g) Includes commitments to purchase coal, nuclear fuel, and natural gas, as well as the related transportation and storage. In most cases, these contracts contain provisions for price escalation, minimum purchase levels, and other financial commitments. Natural gas purchase commitments are based on various indices at the time of delivery. Amounts reflected for natural gas purchase commitments have been estimated based on the New York Mercantile Exchange future prices at December 31, 2012.

(h) Includes long-term service agreements and contracts for the procurement of limestone. Long-term service agreements include price escalation based on inflation indices.

(i) Projections of nuclear decommissioning trust fund contributions are based on the 2010 ARP. See Note 1 to the financial statements under "Nuclear Decommissioning" for additional information.

(j) The Company forecasts contributions to the pension and other postretirement benefit plans over a three-year period. The Company anticipates no mandatory contributions to the qualified pension plan during the next three years. Amounts presented represent estimated benefit payments for the nonqualified pension plans, estimated non-trust benefit payments for the other postretirement benefit plans, and estimated contributions to the other postretirement benefit plan trusts, all of which will be made from the Company's corporate assets. See Note 2 to the financial statements for additional information related to the pension and other postretirement benefit plans, including estimated benefit payments. Certain benefit payments will be made through the related benefit plans. Other benefit payments will be made from the Company's corporate assets.

Cautionary Statement Regarding Forward-Looking Statements

The Company's 2012 Annual Report contains forward-looking statements. Forward-looking statements include, among other things, statements concerning retail sales, retail rates, customer growth, economic recovery, fuel and environmental cost recovery and other rate actions, current and proposed environmental regulations and related estimated expenditures, access to sources of capital, projections for the qualified pension plan, postretirement benefit plan, and nuclear decommissioning trust fund contributions, financing activities, plans and estimated costs for new generation resources, start and completion dates of construction projects, filings with state and federal regulatory authorities, impact of the Tax Relief Act, impact of the ATRA, estimated sales and purchases under new power sale and purchase agreements, and estimated construction and other expenditures. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "could," "should," "expects," "plans," "anticipates," "believes," "estimates," "projects," "predicts," "potential," or "continue" or the negative of these terms or other similar terminology. There are various factors that could cause actual results to differ materially from those suggested by the forward-looking statements; accordingly, there can be no assurance that such indicated results will be realized. These factors include:

- the impact of recent and future federal and state regulatory changes, including legislative and regulatory initiatives regarding deregulation and restructuring of the electric utility industry, environmental laws including regulation of water, coal combustion byproducts, and emissions of sulfur, nitrogen, carbon, soot, particulate matter, hazardous air pollutants, including mercury, and other substances, financial reform legislation, and also changes in tax and other laws and regulations to which the Company is subject, as well as changes in application of existing laws and regulations;
- current and future litigation, regulatory investigations, proceedings, or inquiries, including the pending EPA civil action against the Company and Internal Revenue Service and state tax audits;
- the effects, extent, and timing of the entry of additional competition in the markets in which the Company operates;
- variations in demand for electricity, including those relating to weather, the general economy and recovery from the recent recession, population and business growth (and declines), the effects of energy conservation measures, and any potential economic impacts resulting from federal fiscal decisions;
- available sources and costs of fuels;
- effects of inflation;
- ability to control costs and avoid cost overruns during the development and construction of facilities, including the development and construction of facilities with designs that have not been finalized or previously constructed, to construct facilities in accordance with the requirements of permits and licenses, and to satisfy any operational and environmental performance standards, including the requirements of tax credits and other incentives;
- investment performance of the Company's employee benefit plans and nuclear decommissioning trust funds;
- advances in technology;
- state and federal rate regulations and the impact of pending and future rate cases and negotiations, including rate cases related to fuel and other cost recovery mechanisms;
- regulatory approvals and actions related to Plant Vogtle Units 3 and 4, including Georgia PSC approvals, NRC actions, and potential DOE loan guarantees;
- the inherent risks involved in operating and constructing nuclear generating facilities, including environmental, health, regulatory, natural disaster, terrorism, or financial risks;
- internal restructuring or other restructuring options that may be pursued;
- potential business strategies, including acquisitions or dispositions of assets or businesses, which cannot be assured to be completed or beneficial to the Company;
- the ability of counterparties of the Company to make payments as and when due and to perform as required;
- the ability to obtain new short- and long-term contracts with wholesale customers;
- the direct or indirect effect on the Company's business resulting from terrorist incidents and the threat of terrorist incidents, including cyber intrusion;
- interest rate fluctuations and financial market conditions and the results of financing efforts, including the Company's credit ratings;
- the impacts of any potential U.S. credit rating downgrade or other sovereign financial issues, including impacts on interest rates, access to capital markets, impacts on currency exchange rates, counterparty performance, and the economy in general, as well as potential impacts on the availability or benefits of proposed DOE loan guarantees;

- the ability of the Company to obtain additional generating capacity at competitive prices;
- catastrophic events such as fires, earthquakes, explosions, floods, hurricanes, droughts, pandemic health events such as influenzas, or other similar occurrences;
- the direct or indirect effects on the Company's business resulting from incidents affecting the U.S. electric grid or operation of generating resources;
- the effect of accounting pronouncements issued periodically by standard setting bodies; and
- other factors discussed elsewhere herein and in other reports (including the Form 10-K) filed by the Company from time to time with the SEC.

The Company expressly disclaims any obligation to update any forward-looking statements.

STATEMENTS OF INCOME
For the Years Ended December 31, 2012, 2011, and 2010
Georgia Power Company 2012 Annual Report

	2012	2011	2010
		(in millions)	
Operating Revenues:			
Retail revenues	$ 7,362	$ 8,099	$ 7,608
Wholesale revenues, non-affiliates	281	341	380
Wholesale revenues, affiliates	20	32	53
Other revenues	335	328	308
Total operating revenues	7,998	8,800	8,349
Operating Expenses:			
Fuel	2,051	2,789	3,102
Purchased power, non-affiliates	315	390	368
Purchased power, affiliates	666	713	578
Other operations and maintenance	1,644	1,777	1,734
Depreciation and amortization	745	715	558
Taxes other than income taxes	374	369	344
Total operating expenses	5,795	6,753	6,684
Operating Income	2,203	2,047	1,665
Other Income and (Expense):			
Allowance for equity funds used during construction	53	96	147
Interest expense, net of amounts capitalized	(366)	(343)	(375)
Other income (expense), net	(17)	(13)	(17)
Total other income and (expense)	(330)	(260)	(245)
Earnings Before Income Taxes	1,873	1,787	1,420
Income taxes	688	625	453
Net Income	1,185	1,162	967
Dividends on Preferred and Preference Stock	17	17	17
Net Income After Dividends on Preferred and Preference Stock	$ 1,168	$ 1,145	$ 950

The accompanying notes are an integral part of these financial statements.

STATEMENTS OF COMPREHENSIVE INCOME
For the Years Ended December 31, 2012, 2011, and 2010
Georgia Power Company 2012 Annual Report

	2012	2011	2010
		(in millions)	
Net Income	**$ 1,185**	$ 1,162	$ 967
Other comprehensive income (loss):			
Qualifying hedges:			
Reclassification adjustment for amounts included in net income, net of tax of $1, $2, and $6, respectively	**2**	2	10
Total other comprehensive income (loss)	**2**	2	10
Comprehensive Income	**$ 1,187**	$ 1,164	$ 977

The accompanying notes are an integral part of these financial statements.

STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2012, 2011, and 2010
Georgia Power Company 2012 Annual Report

	2012	2011	2010
		(in millions)	
Operating Activities:			
Net income	**$ 1,185**	$ 1,162	$ 967
Adjustments to reconcile net income to net cash provided from operating activities —			
Depreciation and amortization, total	**912**	867	724
Deferred income taxes	**377**	500	342
Allowance for equity funds used during construction	**(53)**	(96)	(147)
Retail fuel cost over recovery—long-term	**123**	—	—
Pension, postretirement, and other employee benefits	**21**	(15)	21
Pension and postretirement funding	**(12)**	(15)	(195)
Other, net	**(12)**	(22)	(93)
Changes in certain current assets and liabilities —			
-Receivables	**205**	235	168
-Fossil fuel stock	**(269)**	(99)	103
-Prepaid income taxes	**(7)**	72	(36)
-Other current assets	**(53)**	(21)	(9)
-Accounts payable	**(165)**	44	(99)
-Accrued taxes	**(76)**	(36)	31
-Accrued compensation	**(18)**	7	62
-Retail fuel cost over-recovery—short-term	**107**	—	—
-Other current liabilities	**30**	49	8
Net cash provided from operating activities	**2,295**	2,632	1,847
Investing Activities:			
Property additions	**(1,723)**	(1,861)	(2,190)
Investment in restricted cash from pollution control bonds	**(284)**	—	—
Distribution of restricted cash from pollution control bonds	**284**	—	—
Nuclear decommissioning trust fund purchases	**(852)**	(1,845)	(1,772)
Nuclear decommissioning trust fund sales	**850**	1,841	1,768
Cost of removal, net of salvage	**(82)**	(42)	(67)
Change in construction payables, net of joint owner portion	**(149)**	123	36
Other investing activities	**(17)**	(7)	(19)
Net cash used for investing activities	**(1,973)**	(1,791)	(2,244)
Financing Activities:			
Increase (decrease) in notes payable, net	**(513)**	(61)	252
Proceeds —			
Capital contributions from parent company	**42**	214	688
Pollution control revenue bonds issuances and remarketings	**284**	604	—
Senior notes issuances	**2,300**	550	1,950
Other long-term debt issuances	**—**	250	—
Redemptions and repurchases —			
Pollution control revenue bonds	**(284)**	(339)	(516)
Senior notes	**(850)**	(427)	(1,112)
Other long-term debt	**(250)**	(303)	—
Long-term debt to affiliate trust	**—**	(206)	—
Payment of preferred and preference stock dividends	**(17)**	(17)	(18)
Payment of common stock dividends	**(983)**	(1,096)	(820)
Other financing activities	**(19)**	(5)	(33)
Net cash provided from (used for) financing activities	**(290)**	(836)	391
Net Change in Cash and Cash Equivalents	**32**	5	**(6)**
Cash and Cash Equivalents at Beginning of Year	**13**	8	14
Cash and Cash Equivalents at End of Year	**$ 45**	$ 13	$ 8
Supplemental Cash Flow Information:			
Cash paid during the period for —			
Interest (net of $21, $37 and $54 capitalized, respectively)	**$ 337**	$ 346	$ 339
Income taxes (net of refunds)	**312**	54	149
Noncash transactions - accrued property additions at year-end	**261**	391	310

The accompanying notes are an integral part of these financial statements.

BALANCE SHEETS
At December 31, 2012 and 2011
Georgia Power Company 2012 Annual Report

Assets	2012	2011
	(in millions)	
Current Assets:		
Cash and cash equivalents	$ 45	$ 13
Receivables —		
Customer accounts receivable	484	571
Unbilled revenues	217	172
Under recovered regulatory clause revenues	—	137
Joint owner accounts receivable	51	87
Other accounts and notes receivable	68	61
Affiliated companies	23	26
Accumulated provision for uncollectible accounts	(6)	(13)
Fossil fuel stock, at average cost	992	723
Materials and supplies, at average cost	452	406
Vacation pay	85	82
Prepaid income taxes	164	71
Other regulatory assets, current	72	108
Other current assets	104	106
Total current assets	2,751	2,550
Property, Plant, and Equipment:		
In service	29,244	27,804
Less accumulated provision for depreciation	10,431	10,296
Plant in service, net of depreciation	18,813	17,508
Other utility plant, net	263	55
Nuclear fuel, at amortized cost	497	443
Construction work in progress	2,893	3,274
Total property, plant, and equipment	22,466	21,280
Other Property and Investments:		
Equity investments in unconsolidated subsidiaries	45	63
Nuclear decommissioning trusts, at fair value	698	667
Miscellaneous property and investments	44	44
Total other property and investments	787	774
Deferred Charges and Other Assets:		
Deferred charges related to income taxes	733	756
Other regulatory assets, deferred	1,798	1,604
Other deferred charges and assets	268	187
Total deferred charges and other assets	2,799	2,547
Total Assets	$ 28,803	$ 27,151

The accompanying notes are an integral part of these financial statements.

BALANCE SHEETS
At December 31, 2012 and 2011
Georgia Power Company 2012 Annual Report

Liabilities and Stockholder's Equity	2012	2011
		(in millions)
Current Liabilities:		
Securities due within one year	$ 1,680	$ 455
Notes payable	2	515
Accounts payable —		
Affiliated	417	337
Other	436	686
Customer deposits	237	213
Accrued taxes —		
Accrued income taxes	6	50
Other accrued taxes	260	304
Accrued interest	100	92
Accrued vacation pay	61	60
Accrued compensation	113	125
Liabilities from risk management activities	30	68
Other regulatory liabilities, current	73	65
Nuclear decommissioning trust securities lending collateral	9	32
Over recovered regulatory clause revenues, current	107	—
Other current liabilities	137	139
Total current liabilities	3,668	3,141
Long-Term Debt (See accompanying statements)	7,994	8,018
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	4,861	4,388
Deferred credits related to income taxes	115	122
Accumulated deferred investment tax credits	208	220
Employee benefit obligations	950	905
Asset retirement obligations	1,097	734
Other cost of removal obligations	63	110
Other deferred credits and liabilities	308	224
Total deferred credits and other liabilities	7,602	6,703
Total Liabilities	19,264	17,862
Preferred Stock (See accompanying statements)	45	45
Preference Stock (See accompanying statements)	221	221
Common Stockholder's Equity (See accompanying statements)	9,273	9,023
Total Liabilities and Stockholder's Equity	$ 28,803	$ 27,151
Commitments and Contingent Matters (See notes)		

The accompanying notes are an integral part of these financial statements.

STATEMENTS OF CAPITALIZATION
At December 31, 2012 and 2011
Georgia Power Company 2012 Annual Report

	2012	2011	2012	2011
	(in millions)		*(percent of total)*	
Long-Term Debt:				
Long-term notes payable —				
Variable rate (0.85% to 0.95% at 1/1/12) due 2012	$ —	$ 250		
Variable rate (0.58% to 0.63% at 1/1/13) due 2013	**650**	650		
5.125% due 2012	—	200		
1.30% to 6.00% due 2013	**1,025**	1,025		
0.625% to 5.25% due 2015	**1,050**	250		
3.00% due 2016	**250**	250		
5.70% due 2017	**450**	450		
2.85% to 8.20% due 2018-2048	**4,425**	3,575		
Total long-term notes payable	**7,850**	6,650		
Other long-term debt —				
Pollution control revenue bonds:				
0.80% to 5.75% due 2022-2049	**919**	916		
Variable rate (0.17% at 1/1/13) due 2016	**4**	4		
Variable rate (0.12% to 0.24% at 1/1/13) due 2018-2052	**861**	864		
Total other long-term debt	**1,784**	1,784		
Capitalized lease obligations	**50**	55		
Unamortized debt discount	**(10)**	(16)		
Total long-term debt (annual interest requirement — $338 million)	**9,674**	8,473		
Less amount due within one year	**1,680**	455		
Long-term debt excluding amount due within one year	**7,994**	8,018	**45.6%**	46.4%
Preferred and Preference Stock:				
Non-cumulative preferred stock				
$25 par value — 6.125%				
Authorized: 50,000,000 shares				
Outstanding: 1,800,000 shares	**45**	45		
Non-cumulative preference stock				
$100 par value — 6.50%				
Authorized: 15,000,000 shares				
Outstanding: 2,250,000 shares	**221**	221		
Total preferred and preference stock (annual dividend requirement — $17 million)	**266**	266	**1.5**	1.5
Common Stockholder's Equity:				
Common stock, without par value —				
Authorized: 20,000,000 shares				
Outstanding: 9,261,500 shares	**398**	398		
Paid-in capital	**5,585**	5,522		
Retained earnings	**3,297**	3,112		
Accumulated other comprehensive loss	**(7)**	(9)		
Total common stockholder's equity	**9,273**	9,023	**52.9**	52.1
Total Capitalization	**$ 17,533**	$ 17,307	**100.0%**	100.0%

The accompanying notes are an integral part of these financial statements.

STATEMENTS OF COMMON STOCKHOLDER'S EQUITY
For the Years Ended December 31, 2012, 2011, and 2010
Georgia Power Company 2012 Annual Report

	Number of Common Shares Issued	Common Stock	Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
			(in millions)			
Balance at December 31, 2009	9	$ 398	$ 4,593	$ 2,933	$ (21)	$ 7,903
Net income after dividends on preferred and preference stock	—	—	—	950	—	950
Capital contributions from parent company	—	—	698	—	—	698
Other comprehensive income (loss)	—	—	—	—	10	10
Cash dividends on common stock	—	—	—	(820)	—	(820)
Balance at December 31, 2010	9	398	5,291	3,063	(11)	8,741
Net income after dividends on preferred and preference stock	—	—	—	1,145	—	1,145
Capital contributions from parent company	—	—	231	—	—	231
Other comprehensive income (loss)	—	—	—	—	2	2
Cash dividends on common stock	—	—	—	(1,096)	—	(1,096)
Balance at December 31, 2011	**9**	**398**	**5,522**	**3,112**	**(9)**	**9,023**
Net income after dividends on preferred and preference stock	—	—	—	**1,168**	—	**1,168**
Capital contributions from parent company	—	—	**63**	—	—	**63**
Other comprehensive income (loss)	—	—	—	—	**2**	**2**
Cash dividends on common stock	—	—	—	**(983)**	—	**(983)**
Balance at December 31, 2012	**9**	**$ 398**	**$ 5,585**	**$ 3,297**	**$ (7)**	**$ 9,273**

The accompanying notes are an integral part of these financial statements.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

General

Georgia Power Company (the Company) is a wholly owned subsidiary of The Southern Company (Southern Company), which is the parent company of the Company and three other traditional operating companies, as well as Southern Power Company (Southern Power), Southern Company Services, Inc. (SCS), Southern Communications Services, Inc. (SouthernLINC Wireless), Southern Company Holdings, Inc. (Southern Holdings), Southern Nuclear Operating Company, Inc. (Southern Nuclear), and other direct and indirect subsidiaries. The traditional operating companies – the Company, Alabama Power Company (Alabama Power), Gulf Power Company (Gulf Power), and Mississippi Power Company – are vertically integrated utilities providing electric service in four Southeastern states. The Company operates as a vertically integrated utility providing electricity to retail customers within its traditional service area located within the State of Georgia and to wholesale customers in the Southeast. Southern Power constructs, acquires, owns, and manages generation assets, including renewable energy projects, and sells electricity at market-based rates in the wholesale market. SCS, the system service company, provides, at cost, specialized services to Southern Company and its subsidiary companies. SouthernLINC Wireless provides digital wireless communications for use by Southern Company and its subsidiary companies and also markets these services to the public, and provides fiber cable services within the Southeast. Southern Holdings is an intermediate holding company subsidiary, primarily for Southern Company's investments in leveraged leases. Southern Nuclear operates and provides services to the Southern Company system's nuclear power plants, including the Company's Plant Hatch and Plant Vogtle.

The equity method is used for subsidiaries in which the Company has significant influence but does not control.

The Company is subject to regulation by the Federal Energy Regulatory Commission (FERC) and the Georgia Public Service Commission (PSC). The Company follows generally accepted accounting principles (GAAP) in the U.S. and complies with the accounting policies and practices prescribed by its regulatory commissions. The preparation of financial statements in conformity with GAAP requires the use of estimates, and the actual results may differ from those estimates. Certain prior years' data presented in the financial statements have been reclassified to conform to the current year presentation.

Affiliate Transactions

The Company has an agreement with SCS under which the following services are rendered to the Company at direct or allocated cost: general and design engineering, operations, purchasing, accounting, finance and treasury, tax, information technology, marketing, auditing, insurance and pension administration, human resources, systems and procedures, digital wireless communications, and other services with respect to business and operations and power pool transactions. Costs for these services amounted to $540 million in 2012, $550 million in 2011, and $552 million in 2010. Cost allocation methodologies used by SCS prior to the repeal of the Public Utility Holding Company Act of 1935, as amended, were approved by the Securities and Exchange Commission (SEC). Subsequently, additional cost allocation methodologies have been reported to the FERC and management believes they are reasonable. The FERC permits services to be rendered at cost by system service companies.

The Company has an agreement with Southern Nuclear under which the following nuclear-related services are rendered to the Company at cost: general executive and advisory services, general operations, management and technical services, administrative services including procurement, accounting, employee relations, systems and procedures services, strategic planning and budgeting services, and other services with respect to business, operations, and construction management. Costs for these services amounted to $574 million in 2012, $537 million in 2011, and $473 million in 2010.

The Company has entered into several power purchase agreements (PPA) with Southern Power for capacity and energy. Expenses associated with these PPAs were $147 million, $171 million, and $199 million in 2012, 2011, and 2010, respectively. Additionally, the Company had $15 million and $16 million of prepaid capacity expenses included in deferred charges and other assets in the balance sheets at December 31, 2012 and 2011, respectively. See Note 7 under "Fuel and Purchased Power Agreements" for additional information.

The Company has an agreement with Gulf Power under which Gulf Power jointly owns a portion of Plant Scherer Unit 3. Under this agreement, the Company operates Plant Scherer Unit 3 and Gulf Power reimburses the Company for its 25% proportionate share of the related non-fuel expenses, which were $7 million in 2012, $7 million in 2011, and $9 million in 2010. See Note 4 for additional information.

The Company provides incidental services to and receives such services from other Southern Company subsidiaries which are generally minor in duration and amount. Except as described herein, the Company neither provided nor received any material services to or from affiliates in 2012, 2011, or 2010.

See Note 4 for information regarding the Company's ownership in and a PPA with Southern Electric Generating Company (SEGCO). SEGCO plans to add natural gas as the primary fuel source for its generating units in 2015. SEGCO has entered into a joint ownership agreement with Alabama Power, which owns and operates a generating unit adjacent to the SEGCO units, for the ownership of the gas pipeline. SEGCO will own 86% of the pipeline with the remaining 14% owned by Alabama Power.

The traditional operating companies, including the Company, and Southern Power may jointly enter into various types of wholesale energy, natural gas, and certain other contracts, either directly or through SCS as agent. Each participating company may be jointly and severally liable for the obligations incurred under these agreements. See Note 7 under "Fuel and Purchased Power Agreements" for additional information.

New Accounting Pronouncements

In June 2011, the Financial Accounting Standards Board (FASB) issued guidance, ASU 2011-05, *Presentation of Comprehensive Income*, requiring companies to present the total of comprehensive income, the components of net income, and the components of other comprehensive income, in a single continuous statement of comprehensive income or in two separate but consecutive statements. In October 2012, the FASB issued additional guidance, ASU 2012-04, *Technical Corrections and Improvements* (ASU 2012-04), in which it clarified that those companies presenting consecutive statements must begin the statement of comprehensive income with net income. The Company retroactively adopted the guidance in ASU 2012-04 beginning with its financial statements for the three years ended December 31, 2012, 2011, and 2010.

Regulatory Assets and Liabilities

The Company is subject to the provisions of the FASB in accounting for the effects of rate regulation. Regulatory assets represent probable future revenues associated with certain costs that are expected to be recovered from customers through the ratemaking process. Regulatory liabilities represent probable future reductions in revenues associated with amounts that are expected to be credited to customers through the ratemaking process.

Regulatory assets and (liabilities) reflected in the balance sheets at December 31 relate to:

	2012	2011	Note
	(in millions)		
Retiree benefit plans	$ 1,331	$ 1,197	(a, j)
Deferred income tax charges	695	713	(b)
Deferred income tax charges — Medicare subsidy	43	47	(c)
Loss on reacquired debt	190	178	(d)
Asset retirement obligations	131	108	(b, j)
Fuel hedging (realized and unrealized) losses	49	104	(e)
Vacation pay	85	82	(f, j)
Building leases	40	43	(g)
Cancelled construction projects	65	12	(h)
Other regulatory assets	100	108	(c)
Other cost of removal obligations	(94)	(141)	(b)
Deferred income tax credits	(115)	(122)	(b)
State income tax credits	(36)	(62)	(i)
Other regulatory liabilities	(13)	(13)	(d, e)
Total regulatory assets (liabilities), net	$ 2,471	$ 2,254	

Note: The recovery and amortization periods for these regulatory assets and (liabilities) are as follows:

(a) Recovered and amortized over the average remaining service period which may range up to 14 years. See Note 2 under "Pension Plans" and "Other Postretirement Benefits" for additional information.

(b) Asset retirement and other cost of removal obligations and deferred income tax assets are recovered, and deferred income tax liabilities are amortized over the related property lives, which may range up to 65 years. Asset retirement and removal liabilities will be settled and trued up following completion of the related activities. At December 31, 2012, other cost of removal obligations included $31 million that will be amortized during 2013 in accordance with the Company's Alternate Rate Plan for the years 2011 through 2013 (2010 ARP). See Note 3 under "Retail Regulatory Matters – Rate Plans" for additional information.

(c) Recorded and recovered or amortized as approved by the Georgia PSC over periods generally not exceeding 10 years.

(d) Recovered over either the remaining life of the original issue or, if refinanced, over the life of the new issue, which may range up to 50 years.

(e) Fuel hedging assets and liabilities are recorded over the life of the underlying hedged purchase contracts, which generally do not exceed three years. Upon final settlement, actual costs incurred are recovered through the Company's fuel cost recovery mechanism.

(f) Recorded as earned by employees and recovered as paid, generally within one year. This includes both vacation and banked holiday pay.

(g) See Note 6 under "Capital Leases." Recovered over the remaining lives of the buildings through 2026.

(h) Costs associated with construction of environmental controls that will not be completed as a result of unit retirements and deferred in accordance with the 2010 ARP. Amortization is expected to begin January 1, 2014, subject to approval by the Georgia PSC.

(i) Additional tax benefits resulting from the Georgia state income tax credit settlement that are being amortized over a 21-month period that began in April 2012, in accordance with a Georgia PSC order. See Note 5 under "Current and Deferred Income Taxes" for additional information.

(j) Not earning a return as offset in rate base by a corresponding asset or liability.

In the event that a portion of the Company's operations is no longer subject to applicable accounting rules for rate regulation, the Company would be required to write off to income or reclassify to accumulated other comprehensive income (OCI) related regulatory assets and liabilities that are not specifically recoverable through regulated rates. In addition, the Company would be required to determine if any impairment to other assets, including plant, exists and write down the assets, if impaired, to their fair values. All regulatory assets and liabilities are reflected in rate base. See Note 3 under "Retail Regulatory Matters" for additional information.

Revenues

Wholesale capacity revenues are generally recognized on a levelized basis over the appropriate contract period. Energy and other revenues are recognized as services are provided. Unbilled revenues related to retail sales are accrued at the end of each fiscal period. Electric rates for the Company include provisions to adjust billings for fluctuations in fuel costs, the energy component of purchased power costs, and certain other costs. Revenues are adjusted for differences between the actual recoverable costs and amounts billed in current regulated rates.

The Company has a diversified base of customers. No single customer or industry comprises 10% or more of revenues. For all periods presented, uncollectible accounts averaged less than 1% of revenues.

Fuel Costs

Fuel costs are expensed as the fuel is used. Fuel expense includes fuel transportation costs and the cost of purchased emissions allowances as they are used. Fuel expense also includes the amortization of the cost of nuclear fuel and a charge, based on nuclear generation, for the permanent disposal of spent nuclear fuel. See Note 3 under "Nuclear Fuel Disposal Costs" for additional information.

Income and Other Taxes

The Company uses the liability method of accounting for deferred income taxes and provides deferred income taxes for all significant income tax temporary differences. Investment tax credits utilized are deferred and amortized to income as a credit to reduce depreciation over the average life of the related property. Taxes that are collected from customers on behalf of governmental agencies to be remitted to these agencies are presented net on the statements of income.

In accordance with accounting standards related to the uncertainty in income taxes, the Company recognizes tax positions that are "more likely than not" of being sustained upon examination by the appropriate taxing authorities. See Note 5 under "Unrecognized Tax Benefits" for additional information.

Property, Plant, and Equipment

Property, plant, and equipment is stated at original cost less any regulatory disallowances and impairments. Original cost includes: materials; labor; minor items of property; appropriate administrative and general costs; payroll-related costs such as taxes, pensions, and other benefits; and the cost of equity and debt funds used during construction.

The Company's property, plant, and equipment in service consisted of the following at December 31:

		2012		2011
		(in millions)		
Generation	$	**14,567**	$	13,675
Transmission		**4,581**		4,355
Distribution		**8,373**		8,125
General		**1,695**		1,621
Plant acquisition adjustment		**28**		28
Total plant in service	$	**29,244**	$	27,804

The cost of replacements of property, exclusive of minor items of property, is capitalized. The cost of maintenance, repairs, and replacement of minor items of property is charged to other operations and maintenance expense as incurred or performed with the exception of certain generating plant maintenance costs. As mandated by the Georgia PSC, the Company defers and amortizes nuclear refueling outage costs over the unit's operating cycle. The refueling cycles are 18 and 24 months for Plant Vogtle Units 1 and 2 and Plant Hatch Units 1 and 2, respectively. Also, in accordance with a Georgia PSC order, the Company defers the costs of certain significant inspection costs for the combustion turbines at Plant McIntosh and amortizes such costs over 10 years, which approximates the expected maintenance cycle.

Depreciation and Amortization

Depreciation of the original cost of utility plant in service is provided primarily by using composite straight-line rates, which approximated 2.9% in 2012, 2.8% in 2011, and 3.0% in 2010. Depreciation studies are conducted periodically to update the composite rates that are approved by the Georgia PSC and the FERC. When property subject to depreciation is retired or otherwise disposed of in the normal course of business, its original cost, together with the cost of removal, less salvage, is charged to accumulated depreciation. For other property dispositions, the applicable cost and accumulated depreciation are removed from the balance sheet accounts, and a gain or loss is recognized. Minor items of property included in the original cost of the plant are retired when the related property unit is retired.

In 2009, the Georgia PSC approved an accounting order allowing the Company to amortize a portion of its regulatory liability related to other cost of removal obligations. Under the terms of the 2010 ARP, the Company is amortizing approximately $31 million annually of the remaining regulatory liability related to other cost of removal obligations over the three years ending December 31, 2013. See Note 3 under "Retail Regulatory Matters – Rate Plans" for additional information.

Asset Retirement Obligations and Other Costs of Removal

Asset retirement obligations are computed as the present value of the ultimate costs for an asset's future retirement and are recorded in the period in which the liability is incurred. The costs are capitalized as part of the related long-lived asset and depreciated over the asset's useful life. The Company has received accounting guidance from the Georgia PSC allowing the continued accrual of other future retirement costs for long-lived assets that the Company does not have a legal obligation to retire. Accordingly, the accumulated removal costs for these obligations are reflected in the balance sheets as a regulatory liability. See Note 3 under "Retail Regulatory Matters – Rate Plans" for additional information related to the Company's cost of removal regulatory liability.

The asset retirement obligation liability relates to the decommissioning of the Company's nuclear facilities, which include the Company's ownership interests in Plant Hatch and Plant Vogtle Units 1 and 2, as well as various landfill sites, ash ponds, underground storage tanks, and asbestos removal. The Company also has identified retirement obligations related to certain transmission and distribution facilities, including the disposal of polychlorinated biphenyls in certain transformers; leasehold improvements; equipment on customer property; and property associated with the Company's rail lines. However, liabilities for the removal of these assets have not been recorded because the range of time over which the Company may settle these obligations is unknown and cannot be reasonably estimated. The Company will continue to recognize in the statements of income the allowed removal costs in accordance with its regulatory treatment. Any difference between costs recognized in accordance with accounting standards related to asset retirement and environmental obligations and those reflected in rates are recognized as either a regulatory asset or liability in the balance sheets as ordered by the Georgia PSC. See "Nuclear Decommissioning" herein for additional information on amounts included in rates.

Details of the asset retirement obligations included in the balance sheets are as follows:

	2012	2011
	(in millions)	
Balance at beginning of year	$ 757	$ 712
Liabilities incurred	24	—
Liabilities settled	(15)	(9)
Accretion	72	45
Cash flow revisions	267	9
Balance at end of year	$ 1,105	$ 757

Nuclear Decommissioning

The Nuclear Regulatory Commission (NRC) requires licensees of commercial nuclear power reactors to establish a plan for providing reasonable assurance of funds for future decommissioning. The Company has external trust funds (Funds) to comply with the NRC's regulations. Use of the Funds is restricted to nuclear decommissioning activities. The Funds are managed and invested in accordance with applicable requirements of various regulatory bodies, including the NRC, the FERC, and the Georgia PSC, as well as the Internal Revenue Service (IRS). The Funds are required to be held by one or more trustees with an individual net worth of at least $100 million. The FERC requires the Funds' managers to exercise the standard of care in investing that a "prudent investor" would use in the same circumstances. The FERC regulations also require that the Funds' managers may not

invest in any securities of the utility for which it manages funds or its affiliates, except for investments tied to market indices or other mutual funds. While the Company is allowed to prescribe an overall investment policy to the Funds' managers, the Company and its affiliates are not allowed to engage in the day-to-day management of the Funds or to mandate individual investment decisions. Day-to-day management of the investments in the Funds is delegated to unrelated third party managers with oversight by the management of the Company. The Funds' managers are authorized, within certain investment guidelines, to actively buy and sell securities at their own discretion in order to maximize the return on the Funds' investments. The Funds are invested in a tax-efficient manner in a diversified mix of equity and fixed income securities and are reported as trading securities.

The Company records the investment securities held in the Funds at fair value, as discussed in Note 10, as management believes that fair value best represents the nature of the Funds. Gains and losses, whether realized or unrealized, are recorded in the regulatory liability for asset retirement obligations in the balance sheets and are not included in net income or OCI. Fair value adjustments and realized gains and losses are determined on a specific identification basis.

The Funds participate in a securities lending program through the managers of the Funds. Under this program, the Funds' investment securities are loaned to institutional investors for a fee. Securities so loaned are fully collateralized by cash, letters of credit, and securities issued or guaranteed by the U.S. government, its agencies, and the instrumentalities. As of December 31, 2012 and 2011, approximately $91 million and $39 million, respectively, of the fair market value of the Funds' securities were on loan and pledged to creditors under the Funds' managers' securities lending program. The fair value of the collateral received was approximately $93 million and $42 million at December 31, 2012 and 2011, respectively, and can only be sold by the borrower upon the return of the loaned securities. The collateral received is treated as a non-cash item in the statements of cash flows.

At December 31, 2012, investment securities in the Funds totaled $698 million, consisting of equity securities of $280 million, debt securities of $408 million, and $10 million of other securities. At December 31, 2011, investment securities in the Funds totaled $666 million, consisting of equity securities of $244 million, debt securities of $397 million, and $25 million of other securities. These amounts include the investment securities pledged to creditors and collateral received, and exclude receivables related to investment income and pending investment sales, and payables related to pending investment purchases and the lending pool.

Sales of the securities held in the Funds resulted in cash proceeds of $850 million, $1.8 billion, and $1.8 billion in 2012, 2011, and 2010, respectively, all of which were reinvested. For 2012, fair value increases, including reinvested interest and dividends and excluding the Funds' expenses, were $67 million, of which $25 million related to unrealized gains on securities held in the Funds at December 31, 2012. For 2011, fair value increases, including reinvested interest and dividends and excluding the Funds' expenses, were $23 million, of which $9 million related to unrealized losses on securities held in the Funds at December 31, 2011. For 2010, fair value increases, including reinvested interest and dividends and excluding the Funds' expenses, were $74 million, of which $25 million related to unrealized losses on securities held in the Funds at December 31, 2010. While the investment securities held in the Funds are reported as trading securities, the Funds continue to be managed with a long-term focus. Accordingly, all purchases and sales within the Funds are presented separately in the statements of cash flows as investing cash flows, consistent with the nature of and purpose for which the securities were acquired.

The NRC's minimum external funding requirements are based on a generic estimate of the cost to decommission only the radioactive portions of a nuclear unit based on the size and type of reactor. The Company has filed plans with the NRC designed to ensure that, over time, the deposits and earnings of the Funds will provide the minimum funding amounts prescribed by the NRC.

Site study cost is the estimate to decommission a specific facility as of the site study year. The estimated costs of decommissioning are based on the most current study performed in 2012. The site study costs and external trust funds for decommissioning as of December 31, 2012 based on the Company's ownership interests were as follows:

	Plant Hatch	Plant Vogtle Units 1 and 2
Decommissioning periods:		
Beginning year	2034	2047
Completion year	2068	2072
	(in millions)	
Site study costs:		
Radiated structures	$ 549	$ 453
Spent fuel management	131	115
Non-radiated structures	51	76
Total site study costs	$ 731	$ 644
External trust funds	$ 435	$ 256

The decommissioning periods and site study costs for Plant Vogtle Units 1 and 2 reflect the extended operating license approved by the NRC in 2009. The decommissioning cost estimates are based on prompt dismantlement and removal of the plant from service. The actual decommissioning costs may vary from these estimates because of changes in the assumed date of decommissioning, changes in NRC requirements, or changes in the assumptions used in making these estimates.

For ratemaking purposes, the Company's decommissioning costs are based on the NRC generic estimate to decommission the radioactive portion of the facilities and the site study estimate for spent fuel management as of 2009. The Georgia PSC approved annual decommissioning costs for ratemaking of $2 million annually for Plant Hatch for 2011 through 2013. Significant assumptions used to determine the costs for ratemaking include an estimated inflation rate of 2.4% and an estimated trust earnings rate of 4.4%. The Company expects the Georgia PSC to periodically review and adjust, if necessary, the amounts collected in rates for nuclear decommissioning costs.

Allowance for Funds Used During Construction

In accordance with regulatory treatment, the Company records allowance for funds used during construction (AFUDC), which represents the estimated debt and equity costs of capital funds that are necessary to finance the construction of new facilities. While cash is not realized currently from such allowance, AFUDC increases the revenue requirement over the service life of the plant through a higher rate base and higher depreciation. The equity component of AFUDC is not included in calculating taxable income. For the years 2012, 2011, and 2010, the average AFUDC rates were 6.8%, 7.5%, and 8.0%, respectively, and AFUDC capitalized was $75 million, $134 million, and $201 million, respectively. AFUDC, net of income taxes, was 5.7%, 10.4%, and 19.0% of net income after dividends on preferred and preference stock for 2012, 2011, and 2010, respectively. See Note 3 under "Construction – Nuclear" for additional information on the inclusion of construction costs related to the construction of two new nuclear generating units at Plant Vogtle (Plant Vogtle Units 3 and 4) in rate base effective January 1, 2011.

Impairment of Long-Lived Assets and Intangibles

The Company evaluates long-lived assets for impairment when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. The determination of whether an impairment has occurred is based on either a specific regulatory disallowance or an estimate of undiscounted future cash flows attributable to the assets, as compared with the carrying value of the assets. If an impairment has occurred, the amount of the impairment recognized is determined by either the amount of regulatory disallowance or by estimating the fair value of the assets and recording a loss if the carrying value is greater than the fair value. For assets identified as held for sale, the carrying value is compared to the estimated fair value less the cost to sell in order to determine if an impairment loss is required. Until the assets are disposed of, their estimated fair value is re-evaluated when circumstances or events change.

Storm Damage Recovery

The Company defers and recovers certain costs related to damages from major storms as mandated by the Georgia PSC. Under the 2010 ARP effective January 1, 2011, the Company recovers $18 million annually. In 2010, the Company recovered $21 million annually as mandated by the retail rate plan effective January 1, 2008 (2007 Retail Rate Plan). At December 31, 2012, the Company's regulatory asset related to storm damage was $38 million, with approximately $18 million included in other regulatory assets, current and approximately $20 million included as other regulatory assets, deferred. The Company expects the Georgia PSC to periodically review and adjust, if necessary, the amounts collected in rates for storm damage costs.

Environmental Remediation Recovery

The Company maintains a reserve for environmental remediation as mandated by the Georgia PSC. Under the 2010 ARP, effective January 1, 2011, the Company recovers approximately $3 million annually through the environmental compliance cost recovery (ECCR) tariff. In 2010, the Company recovered $1 million annually in accordance with the 2007 Retail Rate Plan. The Company recognizes a liability for environmental remediation costs only when it determines a loss is probable and reduces the reserve as expenditures are incurred. Any difference between the liabilities accrued and cost recovered through rates is deferred as a regulatory asset or liability. The annual recovery amount is expected to be reviewed by the Georgia PSC and adjusted in future regulatory proceedings. As a result of this regulatory treatment, environmental remediation liabilities generally are not expected to have a material impact on the Company's financial statements. As of December 31, 2012, the balance of the environmental remediation liability was $19 million, with approximately $3 million included in other regulatory assets, current and approximately $11 million included as other regulatory assets, deferred. See Note 3 under "Environmental Matters – Environmental Remediation" for additional information.

Cash and Cash Equivalents

For purposes of the financial statements, temporary cash investments are considered cash equivalents. Temporary cash investments are securities with original maturities of 90 days or less.

Materials and Supplies

Generally, materials and supplies include the average cost of transmission, distribution, and generating plant materials. Materials are charged to inventory when purchased and then expensed or capitalized to plant, as appropriate, at weighted average cost when installed.

Fuel Inventory

Fuel inventory includes the average cost of coal, natural gas, oil, transportation, and emissions allowances. Fuel is charged to inventory when purchased and then expensed, at weighted average cost, as used and recovered by the Company through fuel cost recovery rates approved by the Georgia PSC. Emissions allowances granted by the Environmental Protection Agency (EPA) are included in inventory at zero cost.

Financial Instruments

The Company uses derivative financial instruments to limit exposure to fluctuations in interest rates, the prices of certain fuel purchases, and electricity purchases and sales. All derivative financial instruments are recognized as either assets or liabilities (included in "Other" or shown separately as "Risk Management Activities") and are measured at fair value. See Note 10 for additional information. Substantially all of the Company's bulk energy purchases and sales contracts that meet the definition of a derivative are excluded from fair value accounting requirements because they qualify for the "normal" scope exception, and are accounted for under the accrual method. Other derivative contracts qualify as cash flow hedges of anticipated transactions or are recoverable through the Georgia PSC-approved fuel hedging program. This results in the deferral of related gains and losses in OCI or regulatory assets and liabilities, respectively, until the hedged transactions occur. Any ineffectiveness arising from cash flow hedges is recognized currently in net income. Other derivative contracts are marked to market through current period income and are recorded on a net basis in the statements of income. See Note 11 for additional information.

The Company does not offset fair value amounts recognized for multiple derivative instruments executed with the same counterparty under a master netting arrangement. Additionally, the Company had no outstanding collateral repayment obligations or rights to reclaim collateral arising from derivative instruments recognized at December 31, 2012.

The Company is exposed to losses related to financial instruments in the event of counterparties' nonperformance. The Company has established controls to determine and monitor the creditworthiness of counterparties in order to mitigate the Company's exposure to counterparty credit risk.

Comprehensive Income

The objective of comprehensive income is to report a measure of all changes in common stock equity of an enterprise that result from transactions and other economic events of the period other than transactions with owners. Comprehensive income consists of net income, changes in the fair value of qualifying cash flow hedges, and reclassifications for amounts included in net income.

2. RETIREMENT BENEFITS

The Company has a defined benefit, trusteed, pension plan covering substantially all employees. This qualified pension plan is funded in accordance with requirements of the Employee Retirement Income Security Act of 1974, as amended (ERISA). No contributions to the qualified pension plan were made for the year ended December 31, 2012. No mandatory contributions to the qualified pension plan are anticipated for the year ending December 31, 2013. The Company also provides certain defined benefit pension plans for a selected group of management and highly compensated employees. Benefits under these non-qualified pension plans are funded on a cash basis. In addition, the Company provides certain medical care and life insurance benefits for retired employees through other postretirement benefit plans. The Company funds its other postretirement trusts to the extent required by the Georgia PSC and the FERC. For the year ending December 31, 2013, other postretirement trust contributions are expected to total approximately $24 million.

Actuarial Assumptions

The weighted average rates assumed in the actuarial calculations used to determine both the benefit obligations as of the measurement date and the net periodic costs for the pension and other postretirement benefit plans for the following year are presented below. Net periodic benefit costs were calculated in 2009 for the 2010 plan year using discount rates for the pension plans and the other postretirement benefit plans of 5.93% and 5.83%, respectively, and an annual salary increase of 4.18%.

	2012	2011	2010
Discount rate:			
Pension plans	**4.27%**	4.98%	5.52%
Other postretirement benefit plans	**4.04**	4.87	5.40
Annual salary increase	**3.59**	3.84	3.84
Long-term return on plan assets:			
Pension plans	**8.20**	8.45	8.45
Other postretirement benefit plans	**7.24**	7.25	7.24

The Company estimates the expected rate of return on pension plan and other postretirement benefit plan assets using a financial model to project the expected return on each current investment portfolio. The analysis projects an expected rate of return on each of seven different asset classes in order to arrive at the expected return on the entire portfolio relying on each trust's target asset allocation and reasonable capital market assumptions. The financial model is based on four key inputs: anticipated returns by asset class (based in part on historical returns), each trust's target asset allocation, an anticipated inflation rate, and the projected impact of a periodic rebalancing of each trust's portfolio.

An additional assumption used in measuring the accumulated other postretirement benefit obligations (APBO) is the weighted average medical care cost trend rate. The weighted average medical care cost trend rates used in measuring the APBO as of December 31, 2012 were as follows:

	Initial Cost Trend Rate	**Ultimate Cost Trend Rate**	**Year That Ultimate Rate Is Reached**
Pre-65	8.00%	5.00%	2020
Post-65 medical	6.00	5.00	2020
Post-65 prescription	6.00	5.00	2020

An annual increase or decrease in the assumed medical care cost trend rate of 1% would affect the APBO and the service and interest cost components at December 31, 2012 as follows:

	1 Percent Increase	1 Percent Decrease
	(in millions)	
Benefit obligation	$ 61	$ (52)
Service and interest costs	3	(3)

Pension Plans

The total accumulated benefit obligation for the pension plans was $3.1 billion at December 31, 2012 and $2.7 billion at December 31, 2011. Changes in the projected benefit obligations and the fair value of plan assets during the plan years ended December 31, 2012 and 2011 were as follows:

	2012	2011
	(in millions)	
Change in benefit obligation		
Benefit obligation at beginning of year	**$ 2,909**	$ 2,674
Service cost	**60**	57
Interest cost	**141**	144
Benefits paid	**(136)**	(132)
Actuarial loss	**338**	166
Balance at end of year	**3,312**	2,909
Change in plan assets		
Fair value of plan assets at beginning of year	**2,575**	2,621
Actual return on plan assets	**377**	76
Employer contributions	**11**	10
Benefits paid	**(136)**	(132)
Fair value of plan assets at end of year	**2,827**	2,575
Accrued liability	**$ (485)**	$ (334)

At December 31, 2012, the projected benefit obligations for the qualified and non-qualified pension plans were $3.1 billion and $165 million, respectively. All pension plan assets are related to the qualified pension plan.

Amounts recognized in the balance sheets at December 31, 2012 and 2011 related to the Company's pension plans consist of the following:

	2012	2011
	(in millions)	
Other regulatory assets, deferred	**$ 1,132**	$ 995
Current liabilities, other	**(11)**	(10)
Employee benefit obligations	**(474)**	(324)

Presented below are the amounts included in regulatory assets at December 31, 2012 and 2011 related to the defined benefit pension plans that had not yet been recognized in net periodic pension cost along with the estimated amortization of such amounts for 2013.

	2012	2011	Estimated Amortization in 2013
		(in millions)	
Prior service cost	**$ 37**	$ 48	**$ 10**
Net (gain) loss	**1,095**	947	**74**
Other regulatory assets, deferred	**$ 1,132**	$ 995	

The changes in the balance of regulatory assets related to the defined benefit pension plans for the years ended December 31, 2012 and 2011 are presented in the following table:

	Regulatory Assets
	(in millions)
Balance at December 31, 2010	$ 689
Net (gain) loss	324
Change in prior service costs	—
Reclassification adjustments:	
Amortization of prior service costs	(12)
Amortization of net gain (loss)	(6)
Total reclassification adjustments	(18)
Total change	306
Balance at December 31, 2011	$ 995
Net (gain) loss	**182**
Change in prior service costs	—
Reclassification adjustments:	
Amortization of prior service costs	**(12)**
Amortization of net gain (loss)	**(33)**
Total reclassification adjustments	**(45)**
Total change	**137**
Balance at December 31, 2012	**$ 1,132**

Components of net periodic pension cost (income) were as follows:

	2012	2011	2010
		(in millions)	
Service cost	**$ 60**	$ 57	$ 54
Interest cost	**141**	144	145
Expected return on plan assets	**(221)**	(234)	(220)
Recognized net loss	**33**	6	2
Net amortization	**12**	12	13
Net periodic pension cost (income)	**$ 25**	$ (15)	$ (6)

Net periodic pension cost (income) is the sum of service cost, interest cost, and other costs netted against the expected return on plan assets. The expected return on plan assets is determined by multiplying the expected rate of return on plan assets and the market-related value of plan assets. In determining the market-related value of plan assets, the Company has elected to amortize changes in the market value of all plan assets over five years rather than recognize the changes immediately. As a result, the accounting value of plan assets that is used to calculate the expected return on plan assets differs from the current fair value of the plan assets.

Future benefit payments reflect expected future service and are estimated based on assumptions used to measure the projected benefit obligation for the pension plans. At December 31, 2012, estimated benefit payments were as follows:

	Benefit Payments
	(in millions)
2013	$ 148
2014	154
2015	160
2016	166
2017	173
2018 to 2022	952

Other Postretirement Benefits

Changes in the APBO and in the fair value of plan assets during the plan years ended December 31, 2012 and 2011 were as follows:

	2012	2011
	(in millions)	
Change in benefit obligation		
Benefit obligation at beginning of year	$ 774	$ 786
Service cost	7	7
Interest cost	37	41
Benefits paid	(46)	(48)
Actuarial (gain) loss	25	(4)
Plan amendments	—	(12)
Retiree drug subsidy	3	4
Balance at end of year	800	774
Change in plan assets		
Fair value of plan assets at beginning of year	365	393
Actual return (loss) on plan assets	43	(4)
Employer contributions	17	20
Benefits paid	(43)	(44)
Fair value of plan assets at end of year	382	365
Accrued liability	$ (418)	$ (409)

Amounts recognized in the balance sheets at December 31, 2012 and 2011 related to the Company's other postretirement benefit plans consist of the following:

	2012	2011
	(in millions)	
Regulatory assets	**$ 187**	$ 186
Employee benefit obligations	**(418)**	(409)

Presented below are the amounts included in regulatory assets at December 31, 2012 and 2011 related to the other postretirement benefit plans that had not yet been recognized in net periodic other postretirement benefit cost along with the estimated amortization of such amounts for 2013.

	2012	2011	Estimated Amortization in 2013
		(in millions)	
Prior service cost	**$ (4)**	$ (4)	**$ —**
Net (gain) loss	**186**	179	**7**
Transition obligation	**5**	11	**4**
Regulatory assets	**$ 187**	$ 186	

The changes in the balance of regulatory assets related to the other postretirement benefit plans for the plan years ended December 31, 2012 and 2011 are presented in the following table:

	Regulatory Assets
	(in millions)
Balance at December 31, 2010	$ 179
Net (gain) loss	29
Change in prior service costs/transition obligation	(12)
Reclassification adjustments:	
Amortization of transition obligation	(6)
Amortization of prior service costs	(1)
Amortization of net gain (loss)	(3)
Total reclassification adjustments	(10)
Total change	7
Balance at December 31, 2011	$ 186
Net (gain) loss	**11**
Change in prior service costs/transition obligation	**—**
Reclassification adjustments:	
Amortization of transition obligation	**(6)**
Amortization of prior service costs	**—**
Amortization of net gain (loss)	**(4)**
Total reclassification adjustments	**(10)**
Total change	**1**
Balance at December 31, 2012	**$ 187**

Components of the other postretirement benefit plans' net periodic cost were as follows:

	2012	2011	2010
		(in millions)	
Service cost	$ 7	$ 7	$ 9
Interest cost	37	41	44
Expected return on plan assets	(29)	(30)	(30)
Net amortization	10	11	10
Net postretirement cost	$ 25	$ 29	$ 33

Future benefit payments, including prescription drug benefits, reflect expected future service and are estimated based on assumptions used to measure the APBO for the other postretirement benefit plans. Estimated benefit payments are reduced by drug subsidy receipts expected as a result of the Medicare Prescription Drug, Improvement, and Modernization Act of 2003 as follows:

	Benefit Payments	Subsidy Receipts	Total
		(in millions)	
2013	$ 49	$ (5)	$ 44
2014	51	(5)	46
2015	53	(5)	48
2016	55	(6)	49
2017	56	(7)	49
2018 to 2022	282	(36)	246

Benefit Plan Assets

Pension plan and other postretirement benefit plan assets are managed and invested in accordance with all applicable requirements, including ERISA and the Internal Revenue Code of 1986, as amended (Internal Revenue Code). The Company's investment policies for both the pension plan and the other postretirement benefit plans cover a diversified mix of assets, including equity and fixed income securities, real estate, and private equity. Derivative instruments are used primarily to gain efficient exposure to the various asset classes and as hedging tools. The Company minimizes the risk of large losses primarily through diversification but also monitors and manages other aspects of risk.

The composition of the Company's pension plan and other postretirement benefit plan assets as of December 31, 2012 and 2011, along with the targeted mix of assets for each plan, is presented below:

	Target	2012	2011
Pension plan assets:			
Domestic equity	26%	**28%**	29%
International equity	25	**24**	25
Fixed income	23	**27**	23
Special situations	3	**1**	—
Real estate investments	14	**13**	14
Private equity	9	**7**	9
Total	100%	**100%**	100%
Other postretirement benefit plan assets:			
Domestic equity	41%	**34%**	39%
International equity	21	**27**	22
Domestic fixed income	24	**27**	26
Global fixed income	8	**7**	8
Special situations	1	**—**	—
Real estate investments	3	**3**	3
Private equity	2	**2**	2
Total	100%	**100%**	100%

The investment strategy for plan assets related to the Company's qualified pension plan is to be broadly diversified across major asset classes. The asset allocation is established after consideration of various factors that affect the assets and liabilities of the pension plan including, but not limited to, historical and expected returns, volatility, correlations of asset classes, the current level of assets and liabilities, and the assumed growth in assets and liabilities. Because a significant portion of the liability of the pension plan is long-term in nature, the assets are invested consistent with long-term investment expectations for return and risk. To manage the actual asset class exposures relative to the target asset allocation, the Company employs a formal rebalancing program. As additional risk management, external investment managers and service providers are subject to written guidelines to ensure appropriate and prudent investment practices.

Investment Strategies

Detailed below is a description of the investment strategies for each major asset category for the pension and other postretirement benefit plans disclosed above:

- ***Domestic equity.*** A mix of large and small capitalization stocks with generally an equal distribution of value and growth attributes, managed both actively and through passive index approaches.
- ***International equity.*** A mix of growth stocks and value stocks with both developed and emerging market exposure, managed both actively and through passive index approaches.
- ***Fixed income.*** A mix of domestic and international bonds.
- ***Trust-owned life insurance (TOLI).*** Investments of the Company's taxable trusts aimed at minimizing the impact of taxes on the portfolio.
- ***Special situations.*** Investments in opportunistic strategies with the objective of diversifying and enhancing returns and exploiting short-term inefficiencies as well as investments in promising new strategies of a longer-term nature.
- ***Real estate investments.*** Investments in traditional private market, equity-oriented investments in real properties (indirectly through pooled funds or partnerships) and in publicly traded real estate securities.
- ***Private equity.*** Investments in private partnerships that invest in private or public securities typically through privately-negotiated and/or structured transactions, including leveraged buyouts, venture capital, and distressed debt.

Benefit Plan Asset Fair Values

Following are the fair value measurements for the pension plan and the other postretirement benefit plan assets as of December 31, 2012 and 2011. The fair values presented are prepared in accordance with GAAP. For purposes of determining the fair value of the pension plan and other postretirement benefit plan assets and the appropriate level designation, management relies on information provided by the plan's trustee. This information is reviewed and evaluated by management with changes made to the trustee information as appropriate.

Valuation methods of the primary fair value measurements disclosed in the following tables are as follows:

- **Investments in equity securities:** Investments in equity securities such as common stocks, American depositary receipts, and real estate investment trusts that trade on a public exchange are classified as Level 1 investments and are valued at the closing price in the active market. Equity investments with unpublished prices (i.e. pooled funds) are valued as Level 2, when the underlying holdings used to value the investment are comprised of Level 1 or Level 2 equity securities.
- **Investments in fixed income securities:** Investments in fixed income securities are generally classified as Level 2 investments and are valued based on prices reported in the market place. Additionally, the value of fixed income securities takes into consideration certain items such as broker quotes, spreads, yield curves, interest rates, and discount rates that apply to the term of a specific instrument.
- **Investments in TOLI**: Investments in TOLI policies are classified as Level 2 investments and are valued based on the underlying investments held in the policy's separate account. The underlying assets are equity and fixed income pooled funds that are comprised of Level 1 and Level 2 securities.
- **Investments in private equity and real estate:** Investments in private equity and real estate are generally classified as Level 3 as the underlying assets typically do not have observable inputs. The fund manager values the assets using various inputs and techniques depending on the nature of the underlying investments. In the case of private equity, techniques may include purchase multiples for comparable transactions, comparable public company trading multiples, and discounted cash flow analysis. Real estate managers generally use prevailing market capitalization rates, recent sales of comparable investments, and independent third-party appraisals to value underlying real estate investments. The fair value of partnerships is determined by aggregating the value of the underlying assets.

The fair values of pension plan assets as of December 31, 2012 and 2011 are presented below. These fair value measurements exclude cash, receivables related to investment income, pending investments sales, and payables related to pending investment purchases. Assets that are considered special situations investments, primarily real estate investments and private equities, are presented in the tables below based on the nature of the investment.

	Fair Value Measurements Using			
As of December 31, 2012:	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
		(in millions)		
Assets:				
Domestic equity*	$ 413	$ 238	$ —	$ 651
International equity*	324	348	—	672
Fixed income:				
U.S. Treasury, government, and agency bonds	—	183	—	183
Mortgage- and asset-backed securities	—	45	—	45
Corporate bonds	—	312	1	313
Pooled funds	—	142	—	142
Cash equivalents and other	2	195	—	197
Real estate investments	92	—	299	391
Private equity	—	—	211	211
Total	$ 831	$ 1,463	$ 511	$ 2,805

* Level 1 securities consist of actively traded stocks while Level 2 securities consist of pooled funds. Management believes that the portfolio is well-diversified with no significant concentrations of risk.

As of December 31, 2011:	Fair Value Measurements Using: Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
		(in millions)		
Assets:				
Domestic equity*	$ 437	$ 202	$ —	$ 639
International equity*	449	129	—	578
Fixed income:				
U.S. Treasury, government, and agency bonds	—	164	—	164
Mortgage- and asset-backed securities	—	51	—	51
Corporate bonds	—	316	1	317
Pooled funds	—	144	—	144
Cash equivalents and other	—	53	—	53
Real estate investments	83	—	296	379
Private equity	—	—	220	220
Total	$ 969	$ 1,059	$ 517	$ 2,545

* Level 1 securities consist of actively traded stocks while Level 2 securities consist of pooled funds. Management believes that the portfolio is well-diversified with no significant concentrations of risk.

Changes in the fair value measurement of the Level 3 items in the pension plan assets valued using significant unobservable inputs for the years ended December 31, 2012 and 2011 were as follows:

	2012		2011	
	Real Estate Investments	Private Equity	Real Estate Investments	Private Equity
		(in millions)		
Beginning balance	**$ 296**	**$ 220**	$ 258	$ 245
Actual return on investments:				
Related to investments held at year end	**2**	—	24	(5)
Related to investments sold during the year	**1**	**2**	8	14
Total return on investments	**3**	**2**	32	9
Purchases, sales, and settlements	**—**	**(11)**	6	(34)
Transfers into/out of Level 3	**—**	**—**	—	—
Ending balance	**$ 299**	**$ 211**	$ 296	$ 220

The fair values of other postretirement benefit plan assets as of December 31, 2012 and 2011 are presented below. These fair value measurements exclude cash, receivables related to investment income, pending investments sales, and payables related to pending investment purchases. Assets that are considered special situations investments, primarily real estate investments and private equities, are presented in the tables below based on the nature of the investment.

	Fair Value Measurements Using			
As of December 31, 2012:	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
		(in millions)		
Assets:				
Domestic equity*	$ 65	$ 27	$ —	$ 92
International equity*	10	51	—	61
Fixed income:				
U.S. Treasury, government, and agency bonds	—	6	—	6
Mortgage- and asset-backed securities	—	1	—	1
Corporate bonds	—	10	—	10
Pooled funds	—	32	—	32
Cash equivalents and other	—	18	—	18
Trust-owned life insurance	—	142	—	142
Real estate investments	3	—	10	13
Private equity	—	—	7	7
Total	$ 78	$ 287	$ 17	$ 382

* Level 1 securities consist of actively traded stocks while Level 2 securities consist of pooled funds. Management believes that the portfolio is well-diversified with no significant concentrations of risk.

As of December 31, 2011:	Fair Value Measurements Using: Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
		(in millions)		
Assets:				
Domestic equity*	$ 85	$ 24	$ —	$ 109
International equity*	15	31	—	46
Fixed income:				
U.S. Treasury, government, and agency bonds	—	5	—	5
Mortgage- and asset-backed securities	—	1	—	1
Corporate bonds	—	10	—	10
Pooled funds	—	38	—	38
Cash equivalents and other	—	26	—	26
Trust-owned life insurance	—	131	—	131
Real estate investments	3	—	9	12
Private equity	—	—	7	7
Total	$ 103	$ 266	$ 16	$ 385

* Level 1 securities consist of actively traded stocks while Level 2 securities consist of pooled funds. Management believes that the portfolio is well-diversified with no significant concentrations of risk.

Changes in the fair value measurement of the Level 3 items in the other postretirement benefit plan assets valued using significant unobservable inputs for the years ended December 31, 2012 and 2011 were as follows:

	2012		2011	
	Real Estate Investments	Private Equity	Real Estate Investments	Private Equity
		(in millions)		
Beginning balance	$ 9	$ 7	$ 8	$ 8
Actual return on investments:				
Related to investments held at year end	1	—	1	—
Related to investments sold during the year	—	—	—	—
Total return on investments	1	—	1	—
Purchases, sales, and settlements	—	—	—	(1)
Transfers into/out of Level 3	—	—	—	—
Ending balance	$ 10	$ 7	$ 9	$ 7

Employee Savings Plan

The Company also sponsors a 401(k) defined contribution plan covering substantially all employees. The Company provides an 85% matching contribution on up to 6% of an employee's base salary. Total matching contributions made to the plan for 2012, 2011, and 2010 were $24 million, $24 million, and $23 million, respectively.

3. CONTINGENCIES AND REGULATORY MATTERS

General Litigation Matters

The Company is subject to certain claims and legal actions arising in the ordinary course of business. In addition, the Company's business activities are subject to extensive governmental regulation related to public health and the environment, such as regulation of air emissions and water discharges. Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements such as air quality and water standards, has increased generally throughout the U.S. In particular, personal injury, property damage, and other claims for damages alleged to have been caused by carbon dioxide and other emissions, coal combustion byproducts, and alleged exposure to hazardous materials, and/or requests for injunctive relief in connection with such matters, have become more frequent. The ultimate outcome of such pending or potential litigation against the Company cannot be predicted at this time; however, for current proceedings not specifically reported herein, management does not anticipate that the ultimate liabilities, if any, arising from such current proceedings would have a material effect on the Company's financial statements.

Environmental Matters

New Source Review Actions

In 1999, the EPA brought a civil action in the U.S. District Court for the Northern District of Georgia against certain Southern Company subsidiaries, including the Company, alleging that these subsidiaries had violated the New Source Review (NSR) provisions of the Clean Air Act and related state laws at certain coal-fired generating facilities. The EPA alleged NSR violations at three coal-fired generating facilities operated by the Company and five coal-fired generating facilities operated by Alabama Power. The civil action sought penalties and injunctive relief, including an order requiring installation of the best available control technology at the affected units. The case against the Company was administratively closed in 2001 and has not been reopened.

The Company believes it complied with applicable laws and regulations in effect at the time the work in question took place. The Clean Air Act authorizes maximum civil penalties of $25,000 to $37,500 per day, per violation, depending on the date of the alleged violation. An adverse outcome could require substantial capital expenditures that cannot be determined at this time and could possibly require payment of substantial penalties. Such expenditures could affect future results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates. The ultimate outcome of this matter cannot be determined at this time.

Climate Change Litigation

Kivalina Case

In 2008, the Native Village of Kivalina and the City of Kivalina filed a lawsuit in the U.S. District Court for the Northern District of California against several electric utilities (including Southern Company), several oil companies, and a coal company. The plaintiffs allege that the village is being destroyed by erosion allegedly caused by global warming that the plaintiffs attribute to emissions of greenhouse gases by the defendants. The plaintiffs assert claims for public and private nuisance and contend that some of the defendants (including Southern Company) acted in concert and are therefore jointly and severally liable for the plaintiffs' damages. The suit seeks damages for lost property values and for the cost of relocating the village, which is alleged to be $95 million to $400 million. In 2009, the U.S. District Court for the Northern District of California granted the defendants' motions to dismiss the case. On September 21, 2012, the U.S. Court of Appeals for the Ninth Circuit upheld the U.S. District Court for the Northern District of California's dismissal of the case. On November 27, 2012, the U.S. Court of Appeals for the Ninth Circuit denied the plaintiffs' request for review of the decision. On February 25, 2013, the plaintiffs filed a petition for writ of certiorari with the U.S. Supreme Court. Southern Company believes that these claims are without merit. While Southern Company believes the likelihood of loss is remote based on existing case law, it is not possible to predict with certainty whether the Company will incur any liability in connection with this matter. The ultimate outcome of this matter cannot be determined at this time.

Hurricane Katrina Case

In 2005, immediately following Hurricane Katrina, a lawsuit was filed in the U.S. District Court for the Southern District of Mississippi by Ned Comer on behalf of Mississippi residents seeking recovery for property damage and personal injuries caused by Hurricane Katrina. In 2006, the plaintiffs amended the complaint to include Southern Company and many other electric utilities, oil companies, chemical companies, and coal producers. The plaintiffs allege that the defendants contributed to climate change, which contributed to the intensity of Hurricane Katrina. In 2007, the U.S. District Court for the Southern District of Mississippi dismissed the case. On appeal to the U.S. Court of Appeals for the Fifth Circuit, a three-judge panel reversed the U.S. District Court for the Southern District of Mississippi, holding that the case could proceed, but, on rehearing, the full U.S. Court of Appeals for the Fifth Circuit dismissed the plaintiffs' appeal, resulting in reinstatement of the decision of the U.S. District Court for the Southern District of Mississippi in favor of the defendants. In May 2011, the plaintiffs filed an amended version of their class action complaint, arguing that the earlier dismissal was on procedural grounds and under Mississippi law the plaintiffs have a right to re-file. The amended complaint was also filed against numerous chemical, coal, oil, and utility companies, including the Company. On March 20, 2012, the U.S. District Court for the Southern District of Mississippi dismissed the plaintiffs' amended complaint. On April 16, 2012, the plaintiffs appealed the case to the U.S. Court of Appeals for the Fifth Circuit. The Company believes that these claims are without merit. While the Company believes the likelihood of loss is remote based on existing case law, it is not possible to predict with certainty whether the Company will incur any liability in connection with this matter. The ultimate outcome of this matter cannot be determined at this time.

Environmental Remediation

The Company must comply with environmental laws and regulations that cover the handling and disposal of waste and releases of hazardous substances. Under these various laws and regulations, the Company may also incur substantial costs to clean up properties. See Note 1 under "Environmental Remediation Recovery" for additional information.

The Company has been designated or identified as a potentially responsible party (PRP) at sites governed by the Georgia Hazardous Site Response Act and/or by the federal Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA), including a large site in Brunswick, Georgia on the CERCLA National Priorities List (NPL). The parties have completed the removal of wastes from the Brunswick site as ordered by the EPA. Additional cleanup and claims for recovery of natural resource damages at this site or for the assessment and potential cleanup of other sites on the Georgia Hazardous Sites Inventory and the CERCLA NPL are anticipated.

The Company and numerous other entities have been designated by the EPA as PRPs at the Ward Transformer Superfund site located in Raleigh, North Carolina. In September 2011, the EPA issued a Unilateral Administrative Order (UAO) to the Company and 22 other parties, ordering specific remedial action of certain areas at the site. In November 2011, the Company filed a response with the EPA stating it has sufficient cause to believe it is not a liable party under CERCLA. The EPA notified the Company in November 2011 that it is considering enforcement options against the Company and other non-complying UAO recipients. If the court determines that a respondent failed to comply with the UAO without sufficient cause, the EPA may also seek civil penalties of up to $37,500 per day for the violation and punitive damages of up to three times the costs incurred by the EPA as a result of the party's failure to comply with the UAO.

In addition to the EPA's action at this site, the Company, along with many other parties, was sued in a private action by several existing PRPs for cost recovery related to the removal action. On February 1, 2013, the court granted the Company's summary judgment motion ruling that the Company has no liability in the private action. The plaintiffs may appeal the court's order to the U.S. Court of Appeals for the Fourth Circuit.

The ultimate outcome of these matters will depend upon the success of defenses asserted, the ultimate number of PRPs participating in the cleanup, and numerous other factors and cannot be determined at this time; however, as a result of the regulatory treatment described in Note 1 under "Environmental Remediation Recovery," these matters are not expected to have a material impact on the Company's financial statements.

Nuclear Fuel Disposal Costs

Acting through the U.S. Department of Energy (DOE) and pursuant to the Nuclear Waste Policy Act of 1982, the U.S. government entered into contracts with the Company that require the DOE to dispose of spent nuclear fuel and high level radioactive waste generated at Plant Hatch and Plant Vogtle Units 1 and 2. The DOE failed to timely perform and has yet to commence the performance of its contractual and statutory obligation to dispose of spent nuclear fuel beginning no later than January 31, 1998. Consequently, the Company has pursued and continues to pursue legal remedies against the U.S. government for its partial breach of contract.

As a result of its first lawsuit, the Company recovered approximately $27 million, based on its ownership interests, representing

substantially all of the Company's direct costs of the expansion of spent nuclear fuel storage facilities at Plant Hatch and Plant Vogtle Units 1 and 2 from 1998 through 2004. The proceeds were received in July 2012 and credited to the Company accounts where the original costs were charged and were used to reduce rate base, fuel, and cost of service for the benefit of customers.

In 2008, the Company filed a second lawsuit against the U.S. government for the costs of continuing to store spent nuclear fuel at Plant Hatch and Plant Vogtle Units 1 and 2. Damages are being sought for the period from January 1, 2005 through December 31, 2010. Damages will continue to accrue until the issue is resolved or storage is provided. No amounts have been recognized in the financial statements as of December 31, 2012 for any potential recoveries from the second lawsuit. The final outcome of this matter cannot be determined at this time; however, no material impact on the Company's net income is expected as a significant portion of any damage amounts collected from the government is expected to be credited to the Company accounts where the original costs were charged and used to reduce rate base, fuel, and cost of service for the benefit of the customers.

Sufficient pool storage capacity for spent fuel is available at Plant Vogtle Units 1 and 2 to maintain full-core discharge capability for both units into 2014. Construction of an on-site dry storage facility at Plant Vogtle Units 1 and 2 has begun. The facility is expected to begin operation in sufficient time to maintain full-core discharge capability, with additional on-site dry storage to be added as needed. At Plant Hatch, an on-site dry spent fuel storage facility is operational and can be expanded to accommodate spent fuel through the expected life of the plant.

Retail Regulatory Matters

Rate Plans

The economic recession significantly reduced the Company's revenues upon which retail rates were set under the 2007 Retail Rate Plan. In 2009, despite stringent efforts to reduce expenses, the Company's projected retail return on common equity (ROE) for both 2009 and 2010 was below 10.25%. However, in lieu of a full base rate case to increase customer rates as allowed under the 2007 Retail Rate Plan, in 2009, the Georgia PSC approved the Company's request for an accounting order. Under the terms of the accounting order, the Company could amortize up to $108 million of the regulatory liability related to other cost of removal obligations in 2009 and up to $216 million in 2010, limited to the amount needed to earn no more than a 9.75% and 10.15% retail ROE in 2009 and 2010, respectively. For the years ended December 31, 2009 and 2010, the Company amortized $41 million and $174 million, respectively, of the regulatory liability related to other cost of removal obligations.

In 2010, the Georgia PSC approved the 2010 ARP, which became effective January 1, 2011. The terms of the 2010 ARP reflect a settlement agreement among the Company, the Georgia PSC Public Interest Advocacy Staff, and eight other intervenors. Under the terms of the 2010 ARP, the Company is amortizing approximately $92 million of its remaining regulatory liability related to other cost of removal obligations over the three years ending December 31, 2013.

Also under the terms of the 2010 ARP, effective January 1, 2011, the Company increased its (1) traditional base tariff rates by approximately $347 million; (2) Demand-Side Management (DSM) tariff rates by approximately $31 million; (3) ECCR tariff rate by approximately $168 million; and (4) Municipal Franchise Fee (MFF) tariff rate by approximately $16 million, for a total increase in base revenues of approximately $562 million.

Under the 2010 ARP, the following additional base rate adjustments have been made to the Company's tariffs in 2012 and 2013:

- Effective January 1, 2012 and 2013, the DSM tariffs increased by $17 million and $14 million, respectively;
- Effective April 1, 2012 and January 1, 2013, the traditional base tariffs increased by an estimated $122 million and $58 million, respectively, to recover the revenue requirements for Plant McDonough-Atkinson Units 4, 5, and 6 for the period through December 31, 2013; and
- The MFF tariff increased consistently with the adjustments above, as well as those related to the interim fuel rider (IFR) and Nuclear Construction Cost Recovery (NCCR) tariff adjustments described herein under "Fuel Cost Recovery" and "Nuclear Construction."

Under the 2010 ARP, the Company's allowed retail ROE is set at 11.15%, and earnings will be evaluated against a retail ROE range of 10.25% to 12.25%. Two-thirds of any earnings above 12.25% will be directly refunded to customers, with the remaining one-third retained by the Company. There were no refunds related to earnings for 2011 or 2012. The Company is required to file a general base rate case by July 1, 2013, in response to which the Georgia PSC would be expected to determine whether the 2010 ARP should be continued, modified, or discontinued.

Integrated Resource Plans

On March 20, 2012, the Georgia PSC approved the Company's request to decertify and retire Plant Branch Units 1 and 2 as of December 31, 2013 and October 31, 2013, the compliance dates for the respective units under the Georgia Multi-Pollutant Rule,

and an oil-fired unit at Plant Mitchell as of March 26, 2012, as requested in the 2011 Integrated Resource Plan (IRP). The Georgia PSC also approved three PPAs totaling 998 MWs with Southern Power for capacity and energy that will commence in 2015 and end in 2030. On November 21, 2012, the FERC accepted the PPAs.

Separately, on March 20, 2012, the Georgia PSC certified 495 MWs of wholesale capacity to be returned to retail service in 2015 and 2016 under a 2010 agreement, subject to the decertification of any related generating units including 243 MWs of the 16 units described below.

Separately, on October 16, 2012, the Georgia PSC approved a 50 MW PPA with a small power production facility (80 MWs or less) that is a qualifying facility under the Public Utility Regulatory Policies Act of 1978 for capacity and energy that will commence in 2015 and end in 2035.

In addition, on November 20, 2012, the Georgia PSC approved the Company's advanced solar initiative. The Company may acquire up to 210 MWs of additional solar capacity over a three-year period through long-term contracts.

On January 31, 2013, the Company filed its triennial IRP (2013 IRP). The filing included the Company's request to decertify 16 coal- and oil-fired units totaling 2,093 MWs. Several factors, including the cost to comply with existing and future environmental regulations, recent and forecasted economic conditions, and lower natural gas prices, contributed to the decision to close these units.

The Company requested the decertification of Plant Boulevard Units 2 and 3 (28 MWs) upon approval of the 2013 IRP and the decertification of Plant Bowen Unit 6 (32 MWs) by April 16, 2013. Plant Branch Units 3 and 4 (1,016 MWs), Plant Yates Units 1 through 5 (579 MWs), and Plant McManus Units 1 and 2 (122 MWs) will be retired by April 16, 2015, the compliance date of the EPA's final Mercury and Air Toxics Standards (MATS) rule. The Company has also requested a revision to the decertification date of Plant Branch Unit 1 from December 31, 2013 to April 16, 2015. To allow for necessary transmission reliability improvements, the Company expects to seek a one-year extension of the MATS rule compliance date for Plant Kraft Units 1 through 4 (316 MWs) and to retire these units by April 16, 2016.

The filing also included the Company's request to switch the primary fuel source for Plant Yates Units 6 and 7 from coal to natural gas. Additionally, the Company plans to switch the primary fuel source for Plant McIntosh Unit 1 from Central Appalachian coal to Powder River Basin (PRB) coal following further evaluation, including a successful test burn of the PRB fuel.

Under the terms of the 2010 ARP, any costs associated with changes to the Company's approved environmental operating or capital budgets resulting from new or revised environmental regulations through 2013 that are approved by the Georgia PSC in connection with an updated IRP will be deferred as a regulatory asset to be recovered over a time period deemed appropriate by the Georgia PSC. In connection with the retirement decisions, the Company reclassified the retail portion of the net carrying value of Plant Branch Units 1 through 4 from plant in service, net of depreciation, to other utility plant, net. The Company is continuing to depreciate these units using the current composite straight-line rates previously approved by the Georgia PSC. Upon actual retirement, the Georgia PSC approved the continued deferral and amortization of the remaining net carrying values for Plant Branch Units 1 and 2 in its order for the 2011 IRP and the Company has requested similar treatment for Plant Branch Units 3 and 4 in the 2013 IRP. The Company also reclassified the construction work in progress (CWIP) balances totaling $65 million related to environmental controls for Plant Branch Units 1 through 4 and Plant Yates Units 6 and 7 that will not be completed as a result of the retirement decisions to regulatory assets and ceased accruing AFUDC. The Georgia PSC approved a three-year amortization period beginning January 2014 for the $13 million balance relating to Plant Branch Units 1 and 2 in its order for the 2011 IRP and the Company has requested similar treatment for the balances related to Plant Branch Units 3 and 4 and Plant Yates Units 6 and 7 in the 2013 IRP. The Company has also requested that the Georgia PSC approve the deferral of the costs associated with material and supplies remaining at the unit retirement dates to a regulatory asset, to be amortized over a time period deemed appropriate by the Georgia PSC. As a result of this regulatory treatment, the decertification of these units is not expected to have a material impact on the Company's financial statements. The Georgia PSC is scheduled to vote on the 2013 IRP by July 2013.

Fuel Cost Recovery

The Company has established fuel cost recovery rates approved by the Georgia PSC. The Georgia PSC approved reductions in the Company's total annual billings of approximately $43 million effective June 1, 2011, $567 million effective June 1, 2012, and $122 million effective January 1, 2013. In addition, the Georgia PSC has authorized an IFR, which allows the Company to adjust its fuel cost recovery rates prior to the next fuel case if the under or over recovered fuel balance exceeds $215 million through February 2013 and $200 million thereafter. The Company's fuel cost recovery includes costs associated with a natural gas hedging program as revised and approved by the Georgia PSC on February 7, 2013, requiring it to use options and hedges within a 24-month time horizon. See Note 11 under "Energy-Related Derivatives" for additional information. The Company expects to file its next fuel case by March 1, 2014.

The Company's over recovered fuel balance totaled approximately $230 million at December 31, 2012 and is included in current liabilities and other deferred credits and liabilities.

Fuel cost recovery revenues as recorded on the financial statements are adjusted for differences in actual recoverable fuel costs and amounts billed in current regulated rates. Accordingly, changes in the billing factor will not have a significant effect on the Company's revenues or net income, but will affect cash flow.

Nuclear Construction

In 2008, the Company, acting for itself and as agent for Oglethorpe Power Corporation (OPC), the Municipal Electric Authority of Georgia (MEAG Power), and the City of Dalton, Georgia (Dalton), acting by and through its Board of Water, Light, and Sinking Fund Commissioners (collectively, Owners), entered into an agreement with a consortium consisting of Westinghouse Electric Company LLC (Westinghouse) and Stone & Webster, Inc. (collectively, Contractor), pursuant to which the Contractor agreed to design, engineer, procure, construct, and test two AP1000 nuclear units (with electric generating capacity of approximately 1,100 MWs each) and related facilities at Plant Vogtle (Vogtle 3 and 4 Agreement). Under the terms of the Vogtle 3 and 4 Agreement, the Owners agreed to pay a purchase price that is subject to certain price escalations and adjustments, including fixed escalation amounts and index-based adjustments, as well as adjustments for change orders, and performance bonuses for early completion and unit performance. Each Owner is severally (and not jointly) liable for its proportionate share, based on its ownership interest, of all amounts owed to the Contractor under the Vogtle 3 and 4 Agreement. The Company's proportionate share is 45.7%. The Vogtle 3 and 4 Agreement provides for liquidated damages upon the Contractor's failure to fulfill the schedule and performance guarantees. The Contractor's liability to the Owners for schedule and performance liquidated damages and warranty claims is subject to a cap.

Certain payment obligations of Westinghouse and Stone & Webster, Inc. under the Vogtle 3 and 4 Agreement are guaranteed by Toshiba Corporation and The Shaw Group, Inc., respectively. In the event of certain credit rating downgrades of any Owner, such Owner will be required to provide a letter of credit or other credit enhancement. The Owners may terminate the Vogtle 3 and 4 Agreement at any time for their convenience, provided that the Owners will be required to pay certain termination costs and, at certain stages of the work, cancellation fees to the Contractor. The Contractor may terminate the Vogtle 3 and 4 Agreement under certain circumstances, including certain Owner suspension or delays of work, action by a governmental authority to permanently stop work, certain breaches of the Vogtle 3 and 4 Agreement by the Owners, Owner insolvency, and certain other events.

In 2009, the Georgia PSC originally certified construction costs of $6.4 billion to place Plant Vogtle Units 3 and 4 into service in April 2016 and April 2017, respectively, and approved inclusion of the related CWIP accounts in rate base. Also in 2009, the State of Georgia enacted the Georgia Nuclear Energy Financing Act, which allows the Company to recover financing costs for nuclear construction projects through annual adjustments to an NCCR tariff by including the related CWIP accounts in rate base during the construction period. With respect to Plant Vogtle Units 3 and 4, this legislation allowed the Company, beginning in 2011, to recover an estimated $1.7 billion of related financing costs during the construction period. As a result, in 2009, the Georgia PSC also revised the certified in-service capital cost to approximately $4.4 billion.

The Georgia PSC approved increases to the NCCR tariff of approximately $223 million, $35 million, and $50 million, effective January 1, 2011, 2012, and 2013, respectively. Through the NCCR tariff, the Company is collecting and amortizing to earnings approximately $91 million of financing costs, capitalized in 2009 and 2010, over the five-year period ending December 31, 2015, in addition to the ongoing financing costs. At December 31, 2012, approximately $55 million of these 2009 and 2010 costs remained unamortized in CWIP. At December 31, 2012, the Company's CWIP balance for Plant Vogtle Units 3 and 4 totaled $2.3 billion.

In 2009, the NRC issued an Early Site Permit and Limited Work Authorization which allowed limited work to begin on Plant Vogtle Units 3 and 4. The NRC certified the Westinghouse Design Control Document, as amended (DCD), for the AP1000 nuclear reactor design, effective December 30, 2011, and issued combined construction and operating licenses (COLs) on February 10, 2012. Receipt of the COLs allowed full construction to begin.

On February 16, 2012, separate groups of petitioners filed petitions in the U.S. Court of Appeals for the District of Columbia Circuit seeking judicial review of the NRC's issuance of the COLs and certification of the DCD. These petitions were consolidated on April 3, 2012. On April 18, 2012, another group of petitioners filed a motion to stay the effectiveness of the COLs with the U.S. District Court for the District of Columbia. On July 11, 2012, the U.S. Court of Appeals for the District of Columbia Circuit denied the petitioners' motion to stay the effectiveness of the COLs. The Company has intervened in, and intends to vigorously contest, these petitions. Additional technical and procedural challenges to the construction and licensing of Plant Vogtle Units 3 and 4, at the federal and state level, are expected as construction proceeds.

The Company is required to file semi-annual Vogtle Construction Monitoring (VCM) reports with the Georgia PSC by February 28 and August 31 each year. On February 19, 2013, the Georgia PSC voted to approve the Company's seventh VCM report, including construction capital costs incurred through June 30, 2012 of approximately $2.0 billion. The Company's eighth VCM report requests approval for an additional $0.2 billion of construction capital costs incurred through December 31, 2012. If the projected certified construction capital costs to be borne by the Company increase by 5% or the projected in-service dates are significantly extended, the Company is required to seek an amendment to the Plant Vogtle Units 3 and 4 certificate from the Georgia PSC. Accordingly, the eighth VCM also requests an amendment to the certificate to increase the estimated in-service capital cost of Plant Vogtle Units 3 and 4 to $4.8 billion and to extend the estimated in-service dates to fourth quarter 2017 and fourth quarter 2018 for Plant Vogtle Units 3 and 4, respectively. Associated financing costs during the construction period are estimated to total approximately $2.0 billion.

In July 2012, the Owners and the Contractor began negotiations regarding the costs associated with design changes to the DCD and the delays in the timing of approval of the DCD and issuance of the COLs, including the assertion by the Contractor that the Owners are responsible for these costs under the terms of the Vogtle 3 and 4 Agreement. The Contractor has claimed that its estimated adjustment attributable to the Company (based on the Company's ownership interest) is approximately $425 million (in 2008 dollars) with respect to these issues. The Contractor also has asserted it is entitled to further schedule extensions. The Company has not agreed with either the proposed cost or schedule adjustments or that the Owners have any responsibility for costs related to these issues. On November 1, 2012, the Company and the other Owners filed suit against the Contractor in the U.S. District Court for the Southern District of Georgia seeking a declaratory judgment that the Owners are not responsible for these costs. Also on November 1, 2012, the Contractor filed suit against the Company and the other Owners in the U.S. District Court for the District of Columbia alleging the Owners are responsible for these costs. While litigation has commenced and the Company intends to vigorously defend its positions, the Company expects negotiations with the Contractor to continue with respect to cost and schedule during which negotiations the parties may reach a mutually acceptable compromise of their positions.

In addition, there are processes in place that are designed to assure compliance with the requirements specified in the DCD and the COLs, including rigorous inspections by Southern Nuclear and the NRC that occur throughout construction. During the fourth quarter 2012, certain details of the rebar design for the Plant Vogtle Unit 3 nuclear island were evaluated for consistency with the DCD and a few non-safety-related deviations were identified. On January 15, 2013 and January 18, 2013, Southern Nuclear submitted two license amendment requests to conform the rebar design details to NRC requirements. On January 29, 2013, the NRC issued "no objection" letters in response to the related preliminary amendment requests, enabling completion of final work supporting the pouring of base mat concrete, which is expected to occur following approval of the license amendment requests in March 2013. Various design and other issues are expected to arise as construction proceeds, which may result in additional license amendments or require other resolution. If any license amendment requests are not resolved in a timely manner, there may be delays in the project schedule that could result in increased costs either to the Owners, the Contractor, or both.

As construction continues, additional delays in the fabrication and assembly of structural modules, the failure of such modules to meet applicable standards, or other issues may further impact project schedule and cost. Additional claims by the Contractor or the Company (on behalf of the Owners) are also likely to arise throughout construction. These claims may be resolved through formal and informal dispute resolution procedures under the Vogtle 3 and 4 Agreement, but also may be resolved through litigation.

The ultimate outcome of these matters cannot be determined at this time.

4. JOINT OWNERSHIP AGREEMENTS

The Company and Alabama Power own equally all of the outstanding capital stock of SEGCO, which owns electric generating units with a total rated capacity of 1,020 MWs, as well as associated transmission facilities. The capacity of these units is sold equally to the Company and Alabama Power under a power contract. The Company and Alabama Power make payments sufficient to provide for the operating expenses, taxes, interest expense, and a return on equity. The Company's share of purchased power totaled $107 million in 2012, $141 million in 2011, and $100 million in 2010 and is included in purchased power, affiliates in the statements of income. The Company accounts for SEGCO using the equity method.

The Company owns undivided interests in Plants Vogtle, Hatch, Wansley, and Scherer in varying amounts jointly with OPC, MEAG Power, Dalton, Florida Power & Light Company, Jacksonville Electric Authority, and Gulf Power. Under these agreements, the Company has been contracted to operate and maintain the plants as agent for the co-owners and is jointly and severally liable for third party claims related to these plants. In addition, the Company jointly owns the Rocky Mountain pumped storage hydroelectric plant with OPC who is the operator of the plant. The Company and Florida Power Corporation (Progress Energy Florida) jointly own a combustion turbine unit (Intercession City) operated by Progress Energy Florida.

At December 31, 2012, the Company's percentage ownership and investment (exclusive of nuclear fuel) in jointly-owned facilities in commercial operation with the above entities were as follows:

Facility (Type)	Company Ownership	Plant in Service	Accumulated Depreciation	CWIP
		(in millions)		
Plant Vogtle (nuclear)				
Units 1 and 2	45.7%	$ 3,327	$ 1,996	$ 67
Plant Hatch (nuclear)	50.1	1,037	551	49
Plant Wansley (coal)	53.5	801	240	8
Plant Scherer (coal)				
Units 1 and 2	8.4	161	78	77
Unit 3	75.0	1,127	387	28
Rocky Mountain (pumped storage)	25.4	181	116	—
Intercession City (combustion-turbine)	33.3	12	4	1

The Company's proportionate share of its plant operating expenses is included in the corresponding operating expenses in the statements of income and the Company is responsible for providing its own financing.

The Company also owns 45.7% of Plant Vogtle Units 3 and 4 that are currently under construction. See Note 3 to the financial statements under "Retail Regulatory Matters – Nuclear Construction" for additional information.

5. INCOME TAXES

On behalf of the Company, Southern Company files a consolidated federal income tax return and combined state income tax returns for the States of Alabama, Georgia, and Mississippi. Under a joint consolidated income tax allocation agreement, each subsidiary's current and deferred tax expense is computed on a stand-alone basis and no subsidiary is allocated more current expense than would be paid if it filed a separate income tax return. In accordance with IRS regulations, each company is jointly and severally liable for the federal tax liability.

Current and Deferred Income Taxes

Details of income tax provisions are as follows:

	2012	2011	2010
		(in millions)	
Federal –			
Current	$ 273	$ 106	$ 147
Deferred	370	479	312
	643	585	459
State –			
Current	38	19	(36)
Deferred	7	21	30
	45	40	(6)
Total	$ 688	$ 625	$ 453

The tax effects of temporary differences between the carrying amounts of assets and liabilities in the financial statements and their respective tax bases, which give rise to deferred tax assets and liabilities, are as follows:

	2012	2011
	(in millions)	
Deferred tax liabilities –		
Accelerated depreciation	$ 4,201	$ 3,687
Property basis differences	757	804
Employee benefit obligations	255	257
Under-recovered fuel costs	—	56
Premium on reacquired debt	77	72
Regulatory assets associated with employee benefit obligations	536	481
Asset retirement obligations	446	299
Other	93	103
Total	6,365	5,759
Deferred tax assets –		
Federal effect of state deferred taxes	142	157
Employee benefit obligations	644	585
Other property basis differences	100	106
Other deferred costs	39	55
Cost of removal obligations	29	40
State tax credit carry forward	86	52
Over-recovered fuel costs	89	—
Unbilled fuel revenue	39	45
Asset retirement obligations	446	299
Other	42	63
Total	1,656	1,402
Total deferred tax liabilities, net	4,709	4,357
Portion included in current assets/(liabilities), net	152	31
Accumulated deferred income taxes	$ 4,861	$ 4,388

At December 31, 2012, tax-related regulatory assets were $738 million. These assets are primarily attributable to tax benefits that flowed through to customers in prior years, to deferred taxes previously recognized at rates lower than the current enacted tax law, and to taxes applicable to capitalized interest.

At December 31, 2012, tax-related regulatory liabilities to be credited to customers were $151 million. These liabilities are primarily attributable to deferred taxes previously recognized at rates higher than current enacted tax law and to unamortized investment tax credits. In 2011, the Company recorded a regulatory liability of $62 million related to a settlement with the Georgia Department of Revenue resolving claims for certain tax credits in 2005 through 2009. Amortization of the regulatory liability is occurring ratably over the period from April 2012 through December 2013.

In accordance with regulatory requirements, deferred investment tax credits are amortized over the life of the related property with such amortization normally applied as a credit to reduce depreciation in the statements of income. Credits amortized in this manner amounted to $13 million in 2012, $9 million in 2011, and $13 million in 2010. At December 31, 2012, all investment tax credits available to reduce federal income taxes payable had been utilized, and the Company has $86 million in state investment tax credits that will expire by 2021.

In 2010, the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010 (Tax Relief Act) was signed into law. Major tax incentives in the Tax Relief Act include 100% bonus depreciation for property placed in service after September 8, 2010 and through 2011 (and for certain long-term production-period projects placed in service in 2012) and 50% bonus depreciation for property placed in service in 2012 (and for certain long-term production-period projects to be placed in

service in 2013). The application of the bonus depreciation provisions in the Tax Relief Act significantly increased deferred tax liabilities related to accelerated depreciation.

Effective Tax Rate

A reconciliation of the federal statutory income tax rate to the effective income tax rate is as follows:

	2012	2011	2010
Federal statutory rate	**35.0%**	35.0%	35.0%
State income tax, net of federal deduction	**1.6**	1.5	(0.3)
Non-deductible book depreciation	**1.2**	0.8	1.0
AFUDC equity	**(1.0)**	(1.9)	(3.6)
Other	**(0.1)**	(0.5)	(0.2)
Effective income tax rate	**36.7%**	34.9%	31.9%

The increase in the Company's 2012 effective tax rate is primarily the result of an increase in non-deductible book depreciation and a decrease in non-taxable AFUDC equity. The increase in the Company's 2011 effective tax rate is primarily the result of decreases in non-taxable AFUDC equity and state tax credits.

Unrecognized Tax Benefits

For 2012, the total amount of unrecognized tax benefits decreased by $24 million, resulting in a balance of $23 million as of December 31, 2012.

Changes during the year in unrecognized tax benefits were as follows:

	2012	2011	2010
		(in millions)	
Unrecognized tax benefits at beginning of year	**$ 47**	$ 237	$ 181
Tax positions from current periods	**3**	9	52
Tax positions increase from prior periods	**3**	—	27
Tax positions decrease from prior periods	**(19)**	(87)	(23)
Reductions due to settlements	**(8)**	(112)	—
Reductions due to expired statute of limitations	**(3)**	—	—
Balance at end of year	**$ 23**	$ 47	$ 237

The tax positions from current periods for 2012 relate primarily to the tax accounting method change for repairs-generation assets. See "Tax Method of Accounting for Repairs" herein for additional information. The American Jobs Creation Act of 2004 created a tax deduction for a portion of income attributable to U.S. production activities as defined in Section 199 of the Internal Revenue Code (production activities deduction). The tax positions decrease from prior periods and reductions due to settlements for 2012 primarily relate to Georgia's manufacturer's investment tax credits and the production activities deduction.

In addition, the tax reductions due to expired statute of limitations for 2012 relate to the Georgia jobs and retraining tax credits and the Georgia manufacturer's investment tax credits.

The impact on the Company's effective tax rate, if recognized, was as follows:

	2012	2011	2010
		(in millions)	
Tax positions impacting the effective tax rate	**$ —**	$ 28	$ 202
Tax positions not impacting the effective tax rate	**23**	19	35
Balance of unrecognized tax benefits	**$ 23**	$ 47	$ 237

The tax positions not impacting the effective tax rate for 2012 relate to the timing difference associated with the tax accounting method change for repairs-generation assets. See "Tax Method of Accounting for Repairs" herein for additional information. These amounts are presented on a gross basis without considering the related federal or state income tax impact.

Accrued interest for unrecognized tax benefits was as follows:

	2012	2011	2010
		(in millions)	
Interest accrued at beginning of year	$ 6	$ 27	$ 20
Interest reclassified due to settlements	(6)	(24)	—
Interest accrued during the year	—	3	7
Balance at end of year	$ —	$ 6	$ 27

The Company classifies interest on tax uncertainties as interest expense. The Company did not accrue any penalties on uncertain tax positions.

It is reasonably possible that the amount of the unrecognized tax benefits associated with a majority of the Company's unrecognized tax positions will significantly increase or decrease within 12 months. The resolution of the tax accounting method change for repairs - generation assets, as well as the conclusion or settlement of state audits, could impact the balances significantly. At this time, an estimate of the range of reasonably possible outcomes cannot be determined.

The IRS has audited and closed all of Southern Company's consolidated federal income tax returns prior to 2009 and has settled its audits of Southern Company's consolidated federal income tax returns for 2009 and 2010 in principle, pending final approval. Additionally, the IRS has audited and closed Southern Company's 2011 consolidated federal income tax return. For tax years 2010 through 2013, Southern Company is a participant in the Compliance Assurance Process of the IRS. The audits for the Company's state income tax returns have either been concluded, or the statute of limitations has expired, for years prior to 2007.

Tax Method of Accounting for Repairs

Southern Company submitted a tax accounting method change related to the deductibility of repair costs associated with its subsidiaries' generation, transmission, and distribution systems effective for the 2009 consolidated federal income tax return in 2010. In August 2011, the IRS issued a revenue procedure, which provides a safe harbor method of accounting that taxpayers may use to determine eligible repair costs for transmission and distribution property. The IRS continues to work with the utility industry in an effort to define eligible repair costs for generation assets in a consistent manner for all utilities. The IRS published regulations on the deduction and capitalization of expenditures related to tangible property that generally apply for tax years beginning on or after January 1, 2014. The utility industry anticipates more detailed guidance concerning these regulations. Due to the uncertainty regarding the ultimate resolution of the repair costs for generation assets, an unrecognized tax position has been recorded for the tax accounting method change for repairs-generation assets. The ultimate outcome of this matter cannot be determined at this time; however, it is not expected to materially impact net income.

6. FINANCING

Securities Due Within One Year

A summary of scheduled maturities and redemptions of securities due within one year at December 31 was as follows:

	2012	2011
	(in millions)	
Senior notes	$ 1,675	$ 200
Capital lease	5	5
Bank term loans	—	250
Total	$ 1,680	$ 455

Maturities through 2017 applicable to total long-term debt are as follows: $1.7 billion in 2013; $5 million in 2014; $1.1 billion in 2015; $260 million in 2016; and $456 million in 2017.

Senior Notes

The Company issued $2.3 billion aggregate principal amount of unsecured senior notes in 2012. The proceeds of these issuances were used to repay $850 million of unsecured senior notes and $250 million of an unsecured bank term loan, to repay a portion of the Company's short-term indebtedness, and for general corporate purposes, including the Company's continuous construction program.

At December 31, 2012 and 2011, the Company had $7.9 billion and $6.4 billion of senior notes outstanding, respectively. These senior notes are effectively subordinated to all secured debt of the Company, which aggregated $50 million and $55 million at December 31, 2012 and 2011, respectively, and was related to capital lease obligations.

Pollution Control Revenue Bonds

Pollution control obligations represent loans to the Company from public authorities of funds derived from sales by such authorities of revenue bonds issued to finance pollution control and solid waste disposal facilities. The Company is required to make payments sufficient for the authorities to meet principal and interest requirements of such bonds. The amount of tax-exempt pollution control revenue bonds outstanding at both December 31, 2012 and 2011 was $1.8 billion. Proceeds from certain issuances are restricted until qualifying expenditures are incurred.

In 2012, the Company incurred obligations in connection with issuance by public authorities of an aggregate of $284 million of pollution control revenue bonds. The proceeds of these issuances were used to redeem $284 million of outstanding pollution control bonds.

Bank Term Loans

In March 2012, the Company paid at maturity $250 million aggregate principal amount of variable rate long-term bank notes bearing interest at a rate based on one-month London Interbank Offered Rate (LIBOR).

In May 2012, the Company redeemed $200 million aggregate principal amount of variable rate short-term bank notes due June 15, 2012 bearing interest at a rate based on one-month LIBOR.

At December 31, 2011, the Company had $450 million of bank loans outstanding. There were no bank term loans outstanding at December 31, 2012.

Capital Leases

Assets acquired under capital leases are recorded in the balance sheets as utility plant in service, and the related obligations are classified as long-term debt. At December 31, 2012 and 2011, the Company had a capitalized lease obligation for its corporate headquarters building of $50 million and $55 million, respectively, with an interest rate of 7.9% and 7.4%, respectively. For ratemaking purposes, the Georgia PSC has treated the lease as an operating lease and has allowed only the lease payments in cost of service. The difference between the accrued expense and the lease payments allowed for ratemaking purposes has been deferred and is being amortized to expense as ordered by the Georgia PSC. The annual expense incurred for all capital leases was not material for any year presented. See Note 7 under "Fuel and Purchased Power Agreements" for additional information on capital lease PPAs that become effective in 2015.

Outstanding Classes of Capital Stock

The Company currently has preferred stock, Class A preferred stock, preference stock, and common stock authorized. The Company has shares of its Class A preferred stock, preference stock, and common stock outstanding. The Company's Class A preferred stock ranks senior to the Company's preference stock and common stock with respect to payment of dividends and voluntary or involuntary dissolution. The Company's preference stock ranks senior to the common stock with respect to the payment of dividends and voluntary or involuntary dissolution. The outstanding series of the Class A preferred stock is subject to redemption at the option of the Company at any time at a redemption price equal to 100% of the liquidation amount of the stock. In addition, the Company may redeem the outstanding series of the preference stock at a redemption price equal to 100% of the liquidation amount plus, with respect to any redemption prior to October 1, 2017, a make-whole premium based on the present value of the liquidation amount and future dividends through the first par redemption date.

Dividend Restrictions

The Company can only pay dividends to Southern Company out of retained earnings or paid-in-capital.

Bank Credit Arrangements

At December 31, 2012, committed credit arrangements with banks were as follows:

Expires[a]			
2014	2016	Total	Unused
	(in millions)		
$250	$1,500	$1,750	$1,740

(a) No credit arrangements expire in 2013 or 2015.

The Company expects to renew its credit arrangements, as needed, prior to expiration. All the credit arrangements require payment of commitment fees based on the unused portion of the commitments. Commitment fees average less than 1/4 of 1% for the Company.

The credit arrangements have covenants that limit the Company's debt levels to 65% of total capitalization, as defined in the agreements. For purposes of these definitions, debt excludes certain hybrid securities. In addition, the credit arrangements contain cross default provisions that are restricted only to the indebtedness of the Company. The Company is currently in compliance with all such covenants. None of the arrangements contain material adverse change clauses at the time of borrowings.

A portion of the $1.7 billion of unused credit arrangements provides liquidity support to the Company's variable rate pollution control revenue bonds and its commercial paper borrowings. The amount of variable rate pollution control revenue bonds outstanding requiring liquidity support as of December 31, 2012 was $865 million.

The Company makes short-term borrowings primarily through a commercial paper program that has the liquidity support of the Company's committed bank credit arrangements. The Company may also borrow through various other arrangements with banks. Commercial paper and short-term bank loans are included in notes payable on the balance sheets.

The Company had no short-term debt outstanding at December 31, 2012, excluding $2 million of notes payable related to other energy service contracts. Details of short-term borrowings outstanding at December 31, 2011 were as follows:

	Short-term Debt at the End of the Period[a]	
	Amount Outstanding	Weighted Average Interest Rate
	(in millions)	
December 31, 2011:		
Commercial paper	$ 313	0.2%
Short-term bank debt	200	1.2%
Total	$ 513	0.5%

(a) Excludes notes payable related to other energy service contracts of $2 million.

7. COMMITMENTS

Fuel and Purchased Power Agreements

To supply a portion of the fuel requirements of its generating plants, the Company has entered into various long-term commitments for the procurement and delivery of fossil and nuclear fuel which are not recognized on the balance sheets. In 2012, 2011, and 2010, the Company incurred fuel expense of $2.1 billion, $2.8 billion, and $3.1 billion, respectively, the majority of which was purchased under long-term commitments. The Company expects that a substantial amount of its future fuel needs will continue to be purchased under long-term commitments.

The Company has commitments regarding a portion of a 5% interest in the original cost of Plant Vogtle Units 1 and 2 owned by MEAG Power that are in effect until the latter of the retirement of the plant or the latest stated maturity date of MEAG Power's bonds issued to finance such ownership interest. The payments for capacity are required whether or not any capacity is available. The energy cost is a function of each unit's variable operating costs. Portions of the capacity payments relate to costs in excess of MEAG Power's Plant Vogtle Unit 1 and 2's allowed investment for ratemaking purposes. The present value of these portions at the time of the disallowance was written off. Generally, the cost of such capacity and energy is included in purchased power, non-affiliates in the statements of income. Capacity payments totaled $50 million, $52 million, and $55 million in 2012, 2011, and 2010, respectively.

The Company has also entered into various long-term PPAs, some of which are accounted for as capital or operating leases. Total capacity expense under PPAs accounted for as operating leases was $169 million, $216 million, and $223 million for 2012, 2011, and 2010, respectively. Estimated total long-term obligations at December 31, 2012 were as follows:

Minimum Lease Payments

	Capital Lease PPAs	Operating Lease PPAs	Vogtle Units 1 and 2 Capacity Payments	Total ($)
		(in millions)		
2013	$ —	$ 162	$ 24	$ 186
2014	—	165	19	184
2015	22	223	11	256
2016	22	240	11	273
2017	23	215	8	246
2018 and thereafter	301	2,448	69	2,818
Total	$ 368	$ 3,453	$ 142	$ 3,963
Less: amounts representing executory costs[1]	$ 55			
Net minimum lease payments	$ 313			
Less: amounts representing interest[2]	$ 85			
Present value of net minimum lease payments[3]	$ 228			

(1) Executory costs include items such as taxes, maintenance, and insurance (including the estimated profit thereon).

(2) Calculated at the Company's incremental borrowing rate at the inception of the leases.

(3) When the PPAs begin in 2015, the Company will recognize a capital lease asset and a capital lease obligation of $149 million, equal to the estimated fair value of the leased property.

SCS may enter into various types of wholesale energy and natural gas contracts acting as an agent for the Company and all of the other Southern Company traditional operating companies and Southern Power. Under these agreements, each of the traditional operating companies and Southern Power may be jointly and severally liable. The credit rating of Southern Power is currently below that of the traditional operating companies. Accordingly, Southern Company has entered into keep-well agreements with the Company and each of the other traditional operating companies to ensure the Company will not subsidize or be responsible for any costs, losses, liabilities, or damages resulting from the inclusion of Southern Power as a contracting party under these agreements.

Operating Leases

In addition to the PPA operating leases discussed above, the Company has other operating lease agreements with various terms and expiration dates. Total rent expense was $34 million for 2012, $33 million for 2011, and $35 million for 2010. The Company includes any step rents, fixed escalations, and lease concessions in its computation of minimum lease payments, which are recognized on a straight-line basis over the minimum lease term.

As of December 31, 2012, estimated minimum lease payments under operating leases were as follows:

	Minimum Lease Payments		
	Railcars	Other	Total
		(in millions)	
2013	$ 25	$ 5	$ 30
2014	20	4	24
2015	14	3	17
2016	8	2	10
2017	5	1	6
2018 and thereafter	2	1	3
Total	$ 74	$ 16	$ 90

A portion of the railcar lease obligations is shared with the joint owners of Plants Scherer and Wansley. A majority of the rental expenses related to the railcar leases are recoverable through the fuel cost recovery clause as ordered by the Georgia PSC and the remaining portion is recovered through base rates.

In addition to the above rental commitments, the Company has obligations upon expiration of certain railcar leases with respect to the residual value of the leased property. These leases have terms expiring through 2018 with maximum obligations under these leases of $33 million. At the termination of the leases, the lessee may either exercise its purchase option or the property can be sold to a third party. The Company expects that the fair market value of the leased property would substantially reduce or eliminate the Company's payments under the residual value obligations.

Guarantees

Alabama Power has guaranteed unconditionally the obligation of SEGCO under an installment sale agreement for the purchase of certain pollution control facilities at SEGCO's generating units, pursuant to which $25 million principal amount of pollution control revenue bonds are outstanding. Alabama Power has also guaranteed $50 million in senior notes issued by SEGCO. The Company has agreed to reimburse Alabama Power for the pro rata portion of such obligations corresponding to the Company's then proportionate ownership of stock of SEGCO if Alabama Power is called upon to make such payment under its guaranty.

As discussed earlier in this Note under "Operating Leases," the Company has entered into certain residual value guarantees related to railcar leases.

8. STOCK COMPENSATION

Stock Options

Southern Company provides non-qualified stock options through its Omnibus Incentive Compensation Plan to a large segment of the Company's employees ranging from line management to executives. As of December 31, 2012, there were 1,402 current and former employees of the Company participating in the stock option program, and there were 39 million shares of Southern Company common stock remaining available for awards under the Omnibus Incentive Compensation Plan. The prices of options were at the fair market value of the shares on the dates of grant. These options become exercisable pro rata over a maximum period of three years from the date of grant. The Company generally recognizes stock option expense on a straight-line basis over the vesting period which equates to the requisite service period; however, for employees who are eligible for retirement, the total cost is expensed at the grant date. Options outstanding will expire no later than 10 years after the date of grant, unless terminated earlier by the Southern Company Board of Directors in accordance with the Omnibus Incentive Compensation Plan. For certain stock option awards, a change in control will provide accelerated vesting.

The estimated fair values of stock options granted were derived using the Black-Scholes stock option pricing model. Expected volatility was based on historical volatility of Southern Company's stock over a period equal to the expected term. Southern Company used historical exercise data to estimate the expected term that represents the period of time that options granted to employees are expected to be outstanding. The risk-free rate was based on the U.S. Treasury yield curve in effect at the time of grant that covers the expected term of the stock options.

The following table shows the assumptions used in the pricing model and the weighted average grant-date fair value of stock options granted:

Year Ended December 31	2012	2011	2010
Expected volatility	**17.7%**	17.5%	17.4%
Expected term *(in years)*	**5.0**	5.0	5.0
Interest rate	**0.9%**	2.3%	2.4%
Dividend yield	**4.2%**	4.8%	5.6%
Weighted average grant-date fair value	**$ 3.39**	$ 3.23	$ 2.23

The Company's activity in the stock option program for 2012 is summarized below:

	Shares Subject to Option	Weighted Average Exercise Price
Outstanding at December 31, 2011	7,952,587	$ 33.73
Granted	1,269,725	44.43
Exercised	(2,666,146)	32.77
Cancelled	(8,668)	42.04
Outstanding at December 31, 2012	**6,547,498**	**$ 36.18**
Exercisable at December 31, 2012	**4,196,637**	**$ 33.96**

The number of stock options vested, and expected to vest in the future, as of December 31, 2012 was not significantly different from the number of stock options outstanding at December 31, 2012 as stated above. As of December 31, 2012, the weighted average remaining contractual term for the options outstanding and options exercisable was approximately six years and five years, respectively, and the aggregate intrinsic value for the options outstanding and options exercisable was $45 million and $37 million, respectively.

As of December 31, 2012, the amount of unrecognized compensation cost related to stock option awards not yet vested was immaterial.

The compensation cost and tax benefits related to the grant and exercise of Southern Company stock options to the Company's employees are recognized in the Company's financial statements with a corresponding credit to equity, representing a capital contribution from Southern Company. The amounts were not material for any year presented.

The total intrinsic value of options exercised during the years ended December 31, 2012, 2011, and 2010 was $34 million, $32 million, and $12 million, respectively. The actual tax benefit realized by the Company for the tax deductions from stock option exercises was not material for any of the years presented.

Performance Shares

Southern Company provides performance share award units through its Omnibus Incentive Compensation Plan to a large segment of the Company's employees ranging from line management to executives. The performance share units granted under the plan vest at the end of a three-year performance period which equates to the requisite service period. Employees that retire prior to the end of the three-year period receive a pro rata number of shares, issued at the end of the performance period, based on actual months of service prior to retirement. The value of the award units is based on Southern Company's total shareholder return (TSR) over the three-year performance period which measures Southern Company's relative performance against a group of industry peers. The performance shares are delivered in common stock following the end of the performance period based on Southern Company's actual TSR and may range from 0% to 200% of the original target performance share amount.

The fair value of performance share awards is determined as of the grant date using a Monte Carlo simulation model to estimate the TSR of Southern Company's stock among the industry peers over the performance period. The Company recognizes compensation expense on a straight-line basis over the three-year performance period without remeasurement. Compensation expense for awards where the service condition is met is recognized regardless of the actual number of shares issued. The expected volatility was based on the historical volatility of Southern Company's stock over a period equal to the performance period. The risk-free rate was based on the U.S. Treasury yield curve in effect at the time of grant that covers the performance period of the award units.

The following table shows the assumptions used in the pricing model and the weighted average grant-date fair value of performance share award units granted:

Year Ended December 31	2012	2011	2010
Expected volatility	**16.0%**	19.2%	20.7%
Expected term *(in years)*	**3.0**	3.0	3.0
Interest rate	**0.4%**	1.4%	1.4%
Annualized dividend rate	**$ 1.89**	$ 1.82	$ 1.75
Weighted average grant-date fair value	**$ 41.99**	$ 35.97	$ 30.13

Total unvested performance share units outstanding as of December 31, 2011 were 325,958. During 2012, 152,812 performance share units were granted, 179,917 performance shares were vested, and 18,853 performance share units were forfeited resulting in 280,000 unvested units outstanding at December 31, 2012. In January 2013, the vested performance share award units were converted into 242,938 shares outstanding at a share price of $43.05 for the three-year performance and vesting period ended December 31, 2012.

Total compensation cost for performance share units and the related tax benefit recognized in income were immaterial for all years presented. As of December 31, 2012, the amount of total unrecognized compensation cost related to performance share award units that will be recognized over a weighted-average period of approximately 11 months was immaterial.

9. NUCLEAR INSURANCE

Under the Price-Anderson Amendments Act (Act), the Company maintains agreements of indemnity with the NRC that, together with private insurance, cover third-party liability arising from any nuclear incident occurring at the Company's Plant Hatch and Plant Vogtle Units 1 and 2. The Act provides funds up to $12.6 billion for public liability claims that could arise from a single nuclear incident. Each nuclear plant is insured against this liability to a maximum of $375 million by American Nuclear Insurers (ANI), with the remaining coverage provided by a mandatory program of deferred premiums that could be assessed, after a nuclear incident, against all owners of commercial nuclear reactors. The Company could be assessed up to $117.5 million per incident for each licensed reactor it operates but not more than an aggregate of $17.5 million per incident to be paid in a calendar year for each reactor. Such maximum assessment, excluding any applicable state premium taxes, for the Company, based on its ownership and buyback interests in all licensed reactors, is $232 million, per incident, but not more than an aggregate of $35 million to be paid for each incident in any one year. See Note 4 to the financial statements herein for additional information on joint ownership agreements.

Both the maximum assessment per reactor and the maximum yearly assessment are adjusted for inflation at least every five years. The next scheduled adjustment is due no later than October 29, 2013.

The Company is a member of Nuclear Electric Insurance Limited (NEIL), a mutual insurer established to provide property damage insurance in an amount up to $500 million for members' operating nuclear generating facilities. Additionally, the Company has policies that currently provide decontamination, excess property insurance, and premature decommissioning coverage up to $2.25 billion for losses in excess of the $500 million primary coverage. This excess insurance is also provided by NEIL.

NEIL also covers the additional costs that would be incurred in obtaining replacement power during a prolonged accidental outage at a member's nuclear plant. Members can purchase this coverage, subject to a deductible waiting period of up to 26 weeks, with a maximum per occurrence per unit limit of $490 million. After the deductible period, weekly indemnity payments would be received until either the unit is operational or until the limit is exhausted in approximately three years. The Company purchases the maximum limit allowed by NEIL, subject to ownership limitations. Each facility has elected a 12-week deductible waiting period.

A builders' risk property insurance policy has been purchased from NEIL for the construction of Plant Vogtle Units 3 and 4. This policy provides the Owners up to $2.75 billion for accidental property damage occurring during construction.

Under each of the NEIL policies, members are subject to assessments if losses each year exceed the accumulated funds available to the insurer under that policy. The current maximum annual assessments for the Company under the NEIL policies would be $70 million.

Claims resulting from terrorist acts are covered under both the ANI and NEIL policies (subject to normal policy limits). The aggregate, however, that NEIL will pay for all claims resulting from terrorist acts in any 12-month period is $3.2 billion plus such

additional amounts NEIL can recover through reinsurance, indemnity, or other sources.

For all on-site property damage insurance policies for commercial nuclear power plants, the NRC requires that the proceeds of such policies shall be dedicated first for the sole purpose of placing the reactor in a safe and stable condition after an accident. Any remaining proceeds are to be applied next toward the costs of decontamination and debris removal operations ordered by the NRC, and any further remaining proceeds are to be paid either to the Company or to its debt trustees as may be appropriate under the policies and applicable trust indentures. In the event of a loss, the amount of insurance available might not be adequate to cover property damage and other expenses incurred. Uninsured losses and other expenses, to the extent not recovered from customers, would be borne by the Company and could have a material effect on the Company's financial condition and results of operations.

All retrospective assessments, whether generated for liability, property, or replacement power, may be subject to applicable state premium taxes.

10. FAIR VALUE MEASUREMENTS

Fair value measurements are based on inputs of observable and unobservable market data that a market participant would use in pricing the asset or liability. The use of observable inputs is maximized where available and the use of unobservable inputs is minimized for fair value measurement and reflects a three-tier fair value hierarchy that prioritizes inputs to valuation techniques used for fair value measurement.

- Level 1 consists of observable market data in an active market for identical assets or liabilities.
- Level 2 consists of observable market data, other than that included in Level 1, that is either directly or indirectly observable.
- Level 3 consists of unobservable market data. The input may reflect the assumptions of the Company of what a market participant would use in pricing an asset or liability. If there is little available market data, then the Company's own assumptions are the best available information.

In the case of multiple inputs being used in a fair value measurement, the lowest level input that is significant to the fair value measurement represents the level in the fair value hierarchy in which the fair value measurement is reported.

As of December 31, 2012, assets and liabilities measured at fair value on a recurring basis during the period, together with the level of the fair value hierarchy in which they fall, were as follows:

	Fair Value Measurements Using			
As of December 31, 2012:	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
		(in millions)		
Assets:				
Energy-related derivatives	$ —	$ 11	$ —	$ 11
Nuclear decommissioning trusts:[a]				
Domestic equity	162	1	—	163
Foreign equity	—	117	—	117
U.S. Treasury and government agency securities	—	105	—	105
Municipal bonds	—	55	—	55
Corporate bonds	—	133	—	133
Mortgage and asset backed securities	—	115	—	115
Other investments	—	10	—	10
Cash equivalents	15	—	—	15
Total	$ 177	$ 547	$ —	$ 724
Liabilities:				
Energy-related derivatives	$ —	$ 45	$ —	$ 45

(a) Includes the investment securities pledged to creditors and collateral received, and excludes receivables related to investment income, pending investment sales, and payables related to pending investment purchases and the lending pool. See Note 1 under "Nuclear Decommissioning" for additional information.

As of December 31, 2011, assets and liabilities measured at fair value on a recurring basis during the period, together with the level of the fair value hierarchy in which they fall, were as follows:

	Fair Value Measurements Using			
As of December 31, 2011:	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
		(in millions)		
Assets:				
Energy-related derivatives	$ —	$ 13	$ —	$ 13
Nuclear decommissioning trusts:[a]				
Domestic equity	143	1	—	144
Foreign equity	100	—	—	100
U.S. Treasury and government agency securities	—	25	—	25
Municipal bonds	—	82	—	82
Corporate bonds	—	167	—	167
Mortgage and asset backed securities	—	123	—	123
Other investments	—	25	—	25
Cash equivalents	13	—	—	13
Total	$ 256	$ 436	$ —	$ 692
Liabilities:				
Energy-related derivatives	$ —	$ 95	$ —	$ 95

(a) Includes the investment securities pledged to creditors and collateral received, and excludes receivables related to investment income, pending investment sales, and payables related to pending investment purchases and the lending pool. See Note 1 under "Nuclear Decommissioning" for additional information.

Valuation Methodologies

The energy-related derivatives primarily consist of over-the-counter financial products for natural gas, including, from time to time, basis swaps. These are standard products used within the energy industry and are valued using the market approach. The inputs used are mainly from observable market sources, such as forward natural gas prices, implied volatility, and London Interbank Offered Rate interest rates. See Note 11 for additional information on how these derivatives are used.

For fair value measurements of investments within the nuclear decommissioning trusts, specifically the fixed income assets using significant other observable inputs and unobservable inputs, the primary valuation technique used is the market approach. External pricing vendors are designated for each of the asset classes in the nuclear decommissioning trusts with each security discriminately assigned a primary pricing source, based on similar characteristics.

A market price secured from the primary source vendor is then evaluated by management in its valuation of the assets within the trusts. As a general approach, market pricing vendors gather market data (including indices and market research reports) and integrate relative credit information, observed market movements, and sector news into proprietary pricing models, pricing systems, and mathematical tools. Dealer quotes and other market information including live trading levels and pricing analysts' judgment are also obtained when available.

As of December 31, 2012 and 2011, the fair value measurements of investments calculated at net asset value per share (or its equivalent), as well as the nature and risks of those investments, were as follows:

	Fair Value	Unfunded Commitments	Redemption Frequency	Redemption Notice Period
As of December 31, 2012:	*(in millions)*			
Nuclear decommissioning trusts:				
Foreign equity fund	$ 117	None	Monthly	5 days
Corporate bonds — commingled funds	9	None	Daily	Not applicable
Other — commingled funds	10	None	Daily	Not applicable
Cash equivalents:				
Money market funds	15	None	Daily	Not applicable
As of December 31, 2011:				
Nuclear decommissioning trusts:				
Corporate bonds — commingled funds	$ 32	None	Daily	Not applicable
Other — commingled funds	25	None	Daily	Not applicable
Cash equivalents:				
Money market funds	13	None	Daily	Not applicable

The NRC requires licensees of commissioned nuclear power reactors to establish a plan for providing reasonable assurance of funds for future decommissioning. The foreign equity fund in the nuclear decommissioning trusts seeks to provide long-term capital appreciation. In pursuing this investment objective, the foreign equity fund primarily invests in a diversified portfolio of equity securities of foreign companies, including those in emerging markets. These equity securities may include, but are not limited to, common stocks, preferred stocks, real estate investment trusts, convertible securities and depositary receipts, including American depositary receipts, European depositary receipts and global depositary receipts, and rights and warrants to buy common stocks. The Company may withdraw all or a portion of its investment on the last business day of each month subject to a minimum withdrawal of $1 million, provided that a minimum investment of $10 million remains. If notices of withdrawal exceed 20% of the aggregate value of the foreign equity fund, then the foreign equity fund's board may refuse to permit the withdrawal of all such investments and may scale down the amounts to be withdrawn pro rata and may further determine that any withdrawal that has been postponed will have priority on the subsequent withdrawal date.

The commingled funds in the nuclear decommissioning trusts are invested primarily in a diversified portfolio including, but not limited to, commercial paper, notes, repurchase agreements, and other evidences of indebtedness with a maturity not exceeding 13 months from the date of purchase. The commingled funds will, however, generally maintain a dollar-weighted average portfolio maturity of 90 days or less. The assets may be longer term investment grade fixed income obligations with maturity shortening provisions. The primary objective for the commingled funds is a high level of current income consistent with stability of principal and liquidity. The commingled funds included within corporate bonds represent the investment of cash collateral received under the Funds' managers' securities lending program that can only be sold upon the return of the loaned securities. See Note 1 under "Nuclear Decommissioning" for additional information.

The money market funds are short-term investments of excess funds in various money market mutual funds, which are portfolios of short-term debt securities. The money market funds are regulated by the SEC and typically receive the highest rating from credit rating agencies. Regulatory and rating agency requirements for money market funds include minimum credit ratings and maximum maturities for individual securities and a maximum weighted average portfolio maturity. Redemptions are available on a same day basis up to the full amount of the Company's investment in the money market funds.

As of December 31, 2012 and 2011, other financial instruments for which the carrying amount did not equal fair value were as follows:

	Carrying Amount	Fair Value
	(in millions)	
Long-term debt:		
2012	**$ 9,624**	**$ 10,427**
2011	$ 8,418	$ 9,209

The fair values are determined using Level 2 measurements and are based on quoted market prices for the same or similar issues or on current rates offered to the Company.

11. DERIVATIVES

The Company is exposed to market risks, primarily commodity price risk and interest rate risk. To manage the volatility attributable to these exposures, the Company nets its exposures, where possible, to take advantage of natural offsets and enters into various derivative transactions for the remaining exposures pursuant to the Company's policies in areas such as counterparty exposure and risk management practices. The Company's policy is that derivatives are to be used primarily for hedging purposes and mandates strict adherence to all applicable risk management policies. Derivative positions are monitored using techniques including, but not limited to, market valuation, value at risk, stress testing, and sensitivity analysis. Derivative instruments are recognized at fair value in the balance sheets as either assets or liabilities and are presented on a gross basis.

Energy-Related Derivatives

The Company enters into energy-related derivatives to hedge exposures to electricity, gas, and other fuel price changes. However, due to cost-based rate regulations and other various cost recovery mechanisms, the Company has limited exposure to market volatility in commodity fuel prices and prices of electricity. The Company manages a fuel hedging program, implemented per the guidelines of the Georgia PSC, through the use of financial derivative contracts, which is expected to continue to mitigate price volatility.

To mitigate residual risks relative to movements in gas prices, the Company may enter into fixed-price contracts for natural gas purchases; however, a significant portion of contracts are priced at market.

Energy-related derivative contracts are accounted for in one of two methods:

- *Regulatory Hedges* – Energy-related derivative contracts which are designated as regulatory hedges relate primarily to the Company's fuel hedging program, where gains and losses are initially recorded as regulatory liabilities and assets, respectively, and then are included in fuel expense as the underlying fuel is used in operations and ultimately recovered through the fuel cost recovery mechanism.
- *Not Designated* – Gains and losses on energy-related derivative contracts that are not designated or fail to qualify as hedges are recognized in the statements of income as incurred.

Some energy-related derivative contracts require physical delivery as opposed to financial settlement, and this type of derivative is both common and prevalent within the electric industry. When an energy-related derivative contract is settled physically, any cumulative unrealized gain or loss is reversed and the contract price is recognized in the respective line item representing the actual price of the underlying goods being delivered.

At December 31, 2012, the net volume of energy-related derivative contracts for natural gas positions totaled 105 million mmBtu (million British thermal units), all of which expire by 2017, which is the longest hedge date.

In addition to the volume discussed above, the Company enters into physical natural gas supply contracts that provide the option to sell back excess gas due to operational constraints. The expected volume of natural gas subject to such a feature is 3 million mmBtu for the Company.

Interest Rate Derivatives

The Company may also enter into interest rate derivatives to hedge exposure to changes in interest rates. Derivatives related to existing variable rate securities or forecasted transactions are accounted for as cash flow hedges where the effective portion of the derivatives' fair value gains or losses is recorded in OCI and is reclassified into earnings at the same time the hedged transactions affect earnings. The derivatives employed as hedging instruments are structured to minimize ineffectiveness, which is recorded directly to income.

At December 31, 2012, there were no interest rate derivatives outstanding.

The estimated pre-tax losses that will be reclassified from OCI to interest expense for the 12-month period ending December 31, 2013 are not expected to have a material impact on the Company's financial statements. The Company has deferred gains and losses related to interest rate derivative settlements that are expected to be amortized into earnings through 2037.

Derivative Financial Statement Presentation and Amounts

At December 31, 2012 and 2011, the fair value of energy-related derivatives was reflected in the balance sheets as follows:

	Asset Derivatives			Liability Derivatives		
Derivative Category	**Balance Sheet Location**	**2012**	2011	**Balance Sheet Location**	**2012**	2011
		(in millions)			*(in millions)*	
Derivatives designated as hedging instruments for regulatory purposes						
Energy-related derivatives:						
	Other current assets	**$ 6**	$ 8	Liabilities from risk management activities	**$ 30**	$ 68
	Other deferred charges and assets	**5**	5	Other deferred credits and liabilities	**15**	27
Total derivatives designated as hedging instruments for regulatory purposes		**$ 11**	$ 13		**$ 45**	$ 95

All derivative instruments are measured at fair value. See Note 10 for additional information.

At December 31, 2012 and 2011, the pre-tax effects of unrealized derivative gains (losses) arising from energy-related derivative instruments designated as regulatory hedging instruments and deferred on the balance sheets were as follows:

	Unrealized Losses			Unrealized Gains		
Derivative Category	**Balance Sheet Location**	**2012**	2011	**Balance Sheet Location**	**2012**	2011
		(in millions)			*(in millions)*	
Energy-related derivatives:						
	Other regulatory assets, current	**$ (30)**	$ (68)	Other regulatory liabilities, current	**$ 6**	$ 8
	Other regulatory assets, deferred	**(15)**	(27)	Other deferred credits and liabilities	**5**	5
Total energy-related derivative gains (losses)		**$ (45)**	$ (95)		**$ 11**	$ 13

The pre-tax effects of gains (losses) related to interest rate derivatives designated as cash flow hedging instruments recognized in OCI were not material for any year presented. Gains (losses) reclassified from accumulated OCI into income were as follows:

Gain (Loss) Reclassified from Accumulated OCI into Income (Effective Portion)

	Amount		
Statements of Income Location	**2012**	2011	2010
		(in millions)	
Interest expense, net of amounts capitalized	**$ (3)**	$ (4)	$ (16)

There was no material ineffectiveness recorded in earnings for any period presented. The pre-tax effect of energy-related derivatives not designated as hedging instruments on the statements of income was not material for any year presented.

Contingent Features

The Company does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. There are certain derivatives that could require collateral, but not accelerated payment, in the event of various credit rating changes of certain affiliated companies. At December 31, 2012, the fair value of derivative liabilities with contingent features was $6 million.

At December 31, 2012, the Company had no collateral posted with its derivative counterparties; however, because of the joint and several liability features underlying these derivatives, the maximum potential collateral requirements arising from the credit-risk-related contingent features, at a rating below BBB- and/or Baa3, were $15 million.

Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. The Company participates in certain agreements that could require collateral in the event that one or more Southern Company system power pool participants has a credit rating change to below investment grade.

12. QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

Summarized quarterly financial information for 2012 and 2011 is as follows:

Quarter Ended	Operating Revenues	Operating Income	Net Income After Dividends on Preferred and Preference Stock
		(in millions)	
March 2012	**$ 1,745**	**$ 344**	**$ 167**
June 2012	**2,020**	**535**	**295**
September 2012	**2,498**	**924**	**525**
December 2012	**1,735**	**400**	**181**
March 2011	$ 1,989	$ 393	$ 206
June 2011	2,265	537	309
September 2011	2,788	895	520
December 2011	1,758	222	110

The Company's business is influenced by seasonal weather conditions.

SELECTED FINANCIAL AND OPERATING DATA 2008-2012
Georgia Power Company 2012 Annual Report

	2012	2011	2010	2009	2008
Operating Revenues (in millions)	$ 7,998	$ 8,800	$ 8,349	$ 7,692	$ 8,412
Net Income After Dividends on Preferred and Preference Stock (in millions)	$ 1,168	$ 1,145	$ 950	$ 814	$ 903
Cash Dividends on Common Stock (in millions)	$ 983	$ 1,096	$ 820	$ 739	$ 721
Return on Average Common Equity (percent)	12.76	12.89	11.42	11.01	13.56
Total Assets (in millions)	$ 28,803	$ 27,151	$ 25,914	$ 24,295	$ 22,316
Gross Property Additions (in millions)	$ 1,838	$ 1,981	$ 2,401	$ 2,646	$ 1,953
Capitalization (in millions):					
Common stock equity	$ 9,273	$ 9,023	$ 8,741	$ 7,903	$ 6,879
Preferred and preference stock	266	266	266	266	266
Long-term debt	7,994	8,018	7,931	7,782	7,006
Total (excluding amounts due within one year)	$ 17,533	$ 17,307	$ 16,938	$ 15,951	$ 14,151
Capitalization Ratios (percent):					
Common stock equity	52.9	52.1	51.6	49.5	48.6
Preferred and preference stock	1.5	1.5	1.6	1.7	1.9
Long-term debt	45.6	46.4	46.8	48.8	49.5
Total (excluding amounts due within one year)	100.0	100.0	100.0	100.0	100.0
Customers (year-end):					
Residential	2,062,040	2,047,390	2,049,770	2,043,661	2,039,503
Commercial	297,294	296,143	296,140	295,375	295,925
Industrial	8,246	8,279	8,136	8,202	8,248
Other	7,724	7,521	7,309	6,580	5,566
Total	2,375,304	2,359,333	2,361,355	2,353,818	2,349,242
Employees (year-end)	8,094	8,310	8,330	8,599	9,337

	2012	2011	2010	2009	2008
Operating Revenues (in millions):					
Residential	$ 2,986	$ 3,241	$ 3,072	$ 2,686	$ 2,648
Commercial	2,965	3,217	3,011	2,826	2,917
Industrial	1,322	1,547	1,441	1,318	1,640
Other	89	94	84	82	81
Total retail	7,362	8,099	7,608	6,912	7,286
Wholesale — non-affiliates	281	341	380	395	569
Wholesale — affiliates	20	32	53	112	286
Total revenues from sales of electricity	7,663	8,472	8,041	7,419	8,141
Other revenues	335	328	308	273	271
Total	$ 7,998	$ 8,800	$ 8,349	$ 7,692	$ 8,412
Kilowatt-Hour Sales (in millions):					
Residential	25,742	27,223	29,433	26,272	26,412
Commercial	32,270	32,900	33,855	32,593	33,058
Industrial	23,089	23,519	23,209	21,810	24,164
Other	641	657	663	671	671
Total retail	81,742	84,299	87,160	81,346	84,305
Wholesale — non-affiliates	2,934	3,904	4,662	5,208	9,755
Wholesale — affiliates	600	626	1,000	2,504	3,695
Total	85,276	88,829	92,822	89,058	97,755
Average Revenue Per Kilowatt-Hour (cents):					
Residential	11.60	11.91	10.44	10.22	10.03
Commercial	9.19	9.78	8.89	8.67	8.82
Industrial	5.73	6.58	6.21	6.04	6.79
Total retail	9.01	9.61	8.73	8.50	8.64
Wholesale	8.52	8.23	7.65	6.57	6.36
Total sales	8.99	9.54	8.66	8.33	8.33
Residential Average Annual Kilowatt-Hour Use Per Customer	12,509	13,288	14,367	12,848	12,969
Residential Average Annual Revenue Per Customer	$ 1,451	$ 1,582	$ 1,499	$ 1,314	$ 1,300
Plant Nameplate Capacity Ratings (year-end) (megawatts)	17,984	16,588	15,992	15,995	15,995
Maximum Peak-Hour Demand (megawatts):					
Winter	14,104	14,800	15,614	15,173	14,221
Summer	16,440	16,941	17,152	16,080	17,270
Annual Load Factor (percent)	59.1	59.5	60.9	60.7	58.4
Plant Availability (percent)*:					
Fossil-steam	90.3	88.6	88.6	92.5	91.0
Nuclear	94.1	92.2	94.0	88.4	89.8
Source of Energy Supply (percent):					
Coal	26.6	44.4	51.8	52.3	58.7
Nuclear	18.3	16.6	16.4	16.2	14.8
Hydro	0.7	1.1	1.4	1.8	0.6
Oil and gas	22.0	8.9	8.0	7.7	5.1
Purchased power -					
From non-affiliates	6.8	6.1	5.2	4.4	5.1
From affiliates	25.6	22.9	17.2	17.6	15.7
Total	100.0	100.0	100.0	100.0	100.0

* Beginning in 2012, plant availability is calculated as a weighted equivalent availability.

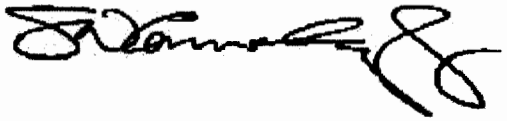
GULF POWER COMPANY

FINANCIAL SECTION

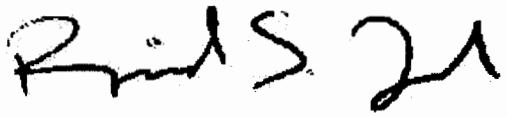
MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING
Gulf Power Company 2012 Annual Report

The management of Gulf Power Company (the Company) is responsible for establishing and maintaining an adequate system of internal control over financial reporting as required by the Sarbanes-Oxley Act of 2002 and as defined in Exchange Act Rule 13a-15(f). A control system can provide only reasonable, not absolute, assurance that the objectives of the control system are met.

Under management's supervision, an evaluation of the design and effectiveness of the Company's internal control over financial reporting was conducted based on the framework in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, management concluded that the Company's internal control over financial reporting was effective as of December 31, 2012.



S. W. Connally, Jr.
President and Chief Executive Officer



Richard S. Teel
Vice President and Chief Financial Officer

February 27, 2013

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of
Gulf Power Company

We have audited the accompanying balance sheets and statements of capitalization of Gulf Power Company (the Company) (a wholly owned subsidiary of The Southern Company) as of December 31, 2012 and 2011, and the related statements of income, comprehensive income, common stockholder's equity, and cash flows for each of the three years in the period ended December 31, 2012. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such financial statements (pages II-311 to II-351) present fairly, in all material respects, the financial position of Gulf Power Company as of December 31, 2012 and 2011, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2012, in conformity with accounting principles generally accepted in the United States of America.

Deloitte & Touche LLP

Atlanta, Georgia
February 27, 2013

OVERVIEW

Business Activities

Gulf Power Company (the Company) operates as a vertically integrated utility providing electricity to retail customers within its traditional service area located in northwest Florida and to wholesale customers in the Southeast.

Many factors affect the opportunities, challenges, and risks of the Company's business of selling electricity. These factors include the ability to maintain a constructive regulatory environment, to maintain and grow energy sales given economic conditions, and to effectively manage and secure timely recovery of costs. These costs include those related to projected long-term demand growth, increasingly stringent environmental standards, reliability, storm restoration following major storms, and fuel. Appropriately balancing required costs and capital expenditures with customer prices will continue to challenge the Company for the foreseeable future.

On March 12, 2012, the Florida Public Service Commission (PSC) approved an increase in retail base rates and charges of $64 million effective April 11, 2012. The amount of the increase includes the previously approved $38.5 million interim retail rate increase implemented in September 2011. The Florida PSC's decision on the amount of the increase also included a determination that none of the base rate revenues collected on an interim basis would be refunded. The Company's authorized retail return on equity (ROE) is a range of 9.25% to 11.25% with new retail base rates set at the midpoint retail ROE of 10.25%. In addition, the Florida PSC also approved a step increase to the Company's retail base rates and charges of $4 million effective in January 2013.

Key Performance Indicators

The Company continues to focus on several key performance indicators. These indicators include customer satisfaction, plant availability, system reliability, and net income after dividends on preference stock. The Company's financial success is directly tied to customer satisfaction. Key elements of ensuring customer satisfaction include outstanding service, high reliability, and competitive prices. Management uses customer satisfaction surveys and reliability indicators to evaluate the Company's results.

Peak season equivalent forced outage rate (Peak Season EFOR) is an indicator of plant availability and efficient generation fleet operations during the months when generation needs are greatest. The rate is calculated by dividing the number of hours of forced outages by total generation hours. The 2012 Peak Season EFOR was better than the target. Transmission and distribution system reliability performance is measured by the frequency and duration of outages. Performance targets for reliability are set internally based on historical performance. The transmission system performance for 2012 did not meet the target for these reliability measures. The distribution system performance for 2012 was better than the target for these reliability measures.

Net income after dividends on preference stock is the primary measure of the Company's financial performance. The Company's 2012 results compared with its targets for some of these key indicators are reflected in the following chart:

Key Performance Indicator	2012 Target Performance	2012 Actual Performance
Customer Satisfaction	**Top quartile in customer surveys**	**Top quartile**
Peak Season EFOR	**4.99% or less**	**0.67%**
Net Income After Dividends on Preference Stock	**$120.7 million**	**$125.9 million**

See RESULTS OF OPERATIONS herein for additional information on the Company's financial performance. The performance achieved in 2012 reflects the continued emphasis the Company places on reliability, customer satisfaction, and financial integrity, as well as the commitment shown by employees in achieving or exceeding management's expectations.

Earnings

The Company's 2012 net income after dividends on preference stock was $125.9 million, an increase of $20.9 million from the previous year. The increase in net income after dividends on preference stock in 2012 was primarily due to higher revenues due to increases in retail base rates and higher wholesale capacity revenues from non-affiliates in 2012. These increases were partially offset by milder weather in 2012, a decrease in retail energy sales in 2012 due to a decrease in customer usage, and a decrease in allowance for funds used during construction (AFUDC) equity, which is non-taxable.

In 2011, net income after dividends on preference stock was $105.0 million, a decrease of $16.5 million from the previous year. The decrease in net income after dividends on preference stock in 2011 was primarily due to an increase in other operations and maintenance expenses in 2011 and closer to normal weather in 2011 compared to 2010, partially offset by higher wholesale capacity revenues from non-affiliates.

RESULTS OF OPERATIONS

A condensed statement of income follows:

	Amount	Increase (Decrease) from Prior Year	
	2012	2012	2011
		(in millions)	
Operating revenues	$ 1,439.7	$ (80.1)	$ (70.4)
Fuel	544.9	(117.4)	(80.0)
Purchased power	74.1	(16.4)	(6.7)
Other operations and maintenance	314.2	2.8	30.7
Depreciation and amortization	141.0	11.4	8.2
Taxes other than income taxes	97.3	(3.9)	(0.5)
Total operating expenses	1,171.5	(123.5)	(48.3)
Operating income	268.2	43.4	(22.1)
Total other income and (expense)	(56.9)	(4.6)	(4.6)
Income taxes	79.2	17.9	(10.2)
Net income	132.1	20.9	(16.5)
Dividends on preference stock	6.2	—	—
Net income after dividends on preference stock	$ 125.9	$ 20.9	$ (16.5)

Operating Revenues

Operating revenues for 2012 were $1.44 billion, reflecting a decrease of $80.1 million from 2011. The following table summarizes the significant changes in operating revenues for the past two years:

	Amount	
	2012	2011
	(in millions)	
Retail — prior year	$ 1,208.5	$ 1,308.7
Estimated change in –		
Rates and pricing	62.7	2.0
Sales growth (decline)	(5.5)	3.9
Weather	(10.7)	(17.8)
Fuel and other cost recovery	(110.5)	(88.3)
Retail — current year	1,144.5	1,208.5
Wholesale revenues –		
Non-affiliates	106.9	133.6
Affiliates	123.6	111.3
Total wholesale revenues	230.5	244.9
Other operating revenues	64.7	66.4
Total operating revenues	$ 1,439.7	$ 1,519.8
Percent change	(5.3)%	(4.4)%

Retail revenues decreased $64.0 million, or 5.3%, in 2012 compared to 2011 primarily as a result of lower fuel revenues due to lower natural gas prices and lower energy sales due to milder weather in 2012 compared to 2011, partially offset by higher revenues resulting from increases in retail base rates. Retail revenues decreased $100.2 million, or 7.7%, in 2011 compared to 2010 primarily as a result of lower fuel revenues and lower energy sales due to closer to normal weather in 2011 compared to 2010, partially offset by an increase related to interim retail rate revenues. See "Energy Sales" below for a discussion of changes in the volume of energy sold, including changes related to sales growth (or decline) and weather.

Revenues associated with changes in rates and pricing include higher revenues due to increases in retail base rates and revenues associated with higher recoverable costs under the Company's energy conservation cost recovery clause, partially offset by a decrease in revenues associated with lower recoverable costs under the Company's environmental cost recovery clause. Annually, the Company petitions the Florida PSC for recovery of projected costs, including any true-up amount from prior periods, and approved rates are implemented each January. The recovery provisions include related expenses and a return on average net investment.

Fuel and other cost recovery provisions include fuel expenses, the energy component of purchased power costs, purchased power capacity costs, and the difference between projected and actual costs and revenues related to energy conservation and environmental compliance. Annually, the Company petitions the Florida PSC for recovery of projected fuel and purchased power costs, including any true-up amount from prior periods, and approved rates are implemented each January. The recovery provisions generally equal the related expenses and have no material effect on earnings.

See Note 1 to the financial statements under "Revenues" and Note 3 to the financial statements under "Retail Regulatory Matters" for additional information regarding the Company's retail base rate case and cost recovery clauses, including the Company's fuel cost recovery, purchased power capacity recovery, environmental cost recovery, and energy conservation cost recovery clauses.

Wholesales revenues from sales to non-affiliated utilities were as follows:

	2012	2011	2010
		(in thousands)	
Unit power sales –			
Capacity	$ **56,379**	$ 52,507	$ 33,482
Energy	**16,520**	44,227	31,379
Total	**72,899**	96,734	64,861
Other power sales –			
Capacity and other	**11,795**	10,717	11,158
Energy	**22,187**	26,104	33,153
Total	**33,982**	36,821	44,311
Total non-affiliated	$ **106,881**	$ 133,555	$ 109,172

Wholesale revenues from sales to non-affiliates include unit power sales under long-term contracts to other utilities in Florida and Georgia. Wholesale revenues from contracts have both capacity and energy components. Capacity revenues reflect the recovery of fixed costs and a return on investment. Energy is generally sold at variable cost. Wholesale revenues from non-affiliates will vary depending on fuel prices, the market prices of wholesale energy compared to the cost of the Company and the Southern Company system's generation, demand for energy within the Southern Company system's service territory, and the availability of the Southern Company system's generation.

Revenues from unit power sales decreased $23.8 million, or 24.6%, in 2012 primarily due to a 62.6% decrease in energy revenues resulting from a 65.2% decrease in kilowatt-hour (KWH) sales as a result of less energy scheduled by unit power customers due to their use of lower cost generation resources to serve their loads, partially offset by a 7.4% increase in capacity revenues related to higher capacity rates. These contracts include change-in-law provisions that provide for recovery of the environmental costs related to the generating resource. Revenues from other power sales decreased $2.8 million, or 7.7%, in 2012 primarily due to decreased energy revenues resulting from a 16.5% decrease in energy rates, partially offset by a 10.1% increase in capacity revenues related to higher capacity rates. Revenues from unit power sales increased $31.9 million, or 49.1%, in 2011 primarily due to a 56.8% increase in capacity revenues related to higher capacity rates as a result of contracts effective in 2010. The increase in unit power sales was also due to increased energy revenues related to a 31.3% increase in KWH sales. Revenues from other power sales decreased $7.5 million, or 16.9%, in 2011 primarily due to decreased energy revenues related to a 9.6% decrease in KWH sales.

Wholesale revenues from sales to affiliated companies will vary from year to year depending on demand and the availability and cost of generating resources at each company. These affiliated sales and purchases are made in accordance with the Intercompany Interchange Contract (IIC), as approved by the Federal Energy Regulatory Commission (FERC). These transactions do not have a significant impact on earnings since the fuel revenue related to energy sales and the cost of energy purchases are both included in the determination of recoverable fuel costs and are generally offset by revenues collected in the Company's fuel cost recovery clause. In 2012, wholesale revenues from sales to affiliates increased $12.3 million from the prior period primarily due to higher energy revenues related to a 67.6% increase in KWH sales resulting from the availability of the Company's lower priced generation resources to serve affiliate demand, partially offset by a 33.8% decrease in the price of energy in 2012. In 2011, wholesale revenues from sales to affiliates increased $1.3 million from the prior period primarily due to higher energy revenues related to a 7.0% increase in KWH sales resulting from the availability of the Company's lower priced generation resources to serve affiliate demand, partially offset by a 5.2% decrease in the price of energy in 2011.

Other operating revenues decreased $1.7 million, or 2.5%, in 2012 primarily due to a $3.0 million decrease in franchise fees, partially offset by a $2.0 million increase in revenues from other energy services. Other operating revenues increased $4.1 million, or 6.7%, in 2011 primarily due to a $3.4 million increase in revenues from other energy services. Revenues from other energy services did not have a material effect on net income since they were generally offset by associated expenses. Franchise fees have no impact on net income.

Energy Sales

Changes in revenues are influenced heavily by the change in the volume of energy sold from year to year. KWH sales for 2012 and the percent change by year were as follows:

	Total KWHs	Total KWH Percent Change		Weather-Adjusted Percent Change	
	2012	2012	2011	2012	2011
	(in millions)				
Residential	**5,054**	**(4.7)%**	(6.1)%	**(0.2)%**	0.5%
Commercial	**3,859**	**(1.4)**	(2.1)	**(0.5)**	—
Industrial	**1,725**	**(4.1)**	6.7	**(4.1)**	6.7
Other	**25**	**(0.6)**	(0.7)	**(0.6)**	(0.7)
Total retail	**10,663**	**(3.4)**	(2.8)	**(0.9)%**	1.3%
Wholesale					
Non-affiliates	**977**	**(51.5)**	20.2		
Affiliates	**4,370**	**67.6**	7.0		
Total wholesale	**5,347**	**15.7**	12.4		
Total energy sales	**16,010**	**2.2 %**	1.2 %		

Changes in retail energy sales are comprised of changes in electricity usage by customers, changes in weather, and changes in the number of customers.

Residential KWH sales and commercial KWH sales decreased in 2012 compared to 2011 primarily due to milder weather in 2012 compared to 2011. Weather-adjusted 2012 KWH sales to residential and commercial customers remained relatively flat as compared to 2011. Residential KWH sales and commercial KWH sales decreased in 2011 compared to 2010 primarily due to closer to normal weather in 2011 compared to 2010. Weather-adjusted 2011 KWH sales to residential and commercial customers remained relatively flat as compared to 2010.

Industrial KWH sales decreased 4.1% in 2012 compared to 2011 primarily due to increased customer co-generation due to the lower cost of natural gas and changes in customer production levels. Industrial KWH sales increased 6.7% in 2011 compared to 2010 primarily resulting from the addition of a new large customer and higher customer load requirements and production levels.

Wholesale KWH sales to non-affiliates decreased 51.5% in 2012 compared to 2011 primarily resulting from less energy scheduled by unit power customers due to their use of lower cost generation resources to serve their loads. Wholesale KWH sales to non-affiliates increased 20.2% in 2011 compared to 2010 primarily resulting from higher KWHs scheduled by unit power customers.

Wholesale KWH sales to affiliates increased 67.6% and 7.0% in 2012 and 2011, respectively, compared to the prior periods primarily resulting from the availability of the Company's lower priced generation resources to serve affiliate demand.

Fuel and Purchased Power Expenses

Fuel costs constitute the single largest expense for the Company. The mix of fuel sources for generation of electricity is determined primarily by demand, the unit cost of fuel consumed, and the availability of generating units. Additionally, the Company purchases a portion of its electricity needs from the wholesale market.

Details of the Company's generation and purchased power were as follows:

	2012	2011	2010
Total generation *(millions of KWHs)*	**9,648**	12,035	13,440
Total purchased power *(millions of KWHs)*	**6,952**	4,349	2,858
Sources of generation *(percent)* –			
Coal	**60**	67	78
Gas	**40**	33	22
Cost of fuel, generated *(cents per net KWH)* –			
Coal	**4.42**	4.97	5.10
Gas	**3.96**	4.06	4.68
Average cost of fuel, generated *(cents per net KWH)*	**4.23**	4.67	5.01
Average cost of purchased power *(cents per net KWH*)*	**3.03**	4.39	5.82

* Average cost of purchased power includes fuel purchased by the Company for tolling agreements where power is generated by the provider.

Total fuel and purchased power expenses were $619.0 million in 2012, a decrease of $133.8 million, or 17.8%, from the prior year costs. The decrease in fuel and purchased power expenses was due to a $129.9 million decrease in the average cost of fuel and purchased power and a $118.2 million decrease related to the volume of KWHs generated. The decrease was partially offset by a $114.3 million increase related to the volume of KWHs purchased. Total fuel and purchased power expenses were $752.8 million in 2011, a decrease of $86.7 million, or 10.3%, from the prior year costs. The decrease in fuel and purchased power expenses was due to a $103.2 million decrease in the average cost of fuel and purchased power and a $70.3 million decrease related to KWHs generated, partially offset by an $86.8 million increase related to KWHs purchased.

From an overall global market perspective, coal prices decreased from levels experienced in 2011 due to lower demand. In the U.S., this decrease was due primarily to relatively lower domestic natural gas prices that contributed to displacement of coal generation by natural gas-fueled generating units. Lower domestic natural gas prices in 2012 were driven by continued robust supplies, including production from shale gas, and only modest increases in overall U.S. consumption.

Fuel and purchased power transactions do not have a significant impact on earnings since energy and capacity expenses are generally offset by energy and capacity revenues through the Company's fuel cost and purchased power capacity recovery clauses. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Fuel Cost Recovery" and "– Purchased Power Capacity Recovery" herein for additional information.

Fuel

Fuel expense was $544.9 million in 2012, a decrease of $117.4 million, or 17.7%, from the prior year costs. The decrease was primarily due to a higher utilization of lower cost natural gas-fired sources, a 2.5% decrease in the average cost of natural gas per KWH generated, and a 19.8% decrease in KWHs generated as a result of displacement of coal-fired generation by energy purchases and lower demand related to milder weather. These decreases were partially offset by a 59.8% increase in KWHs purchased. Fuel expense was $662.3 million in 2011, a decrease of $80.0 million, or 10.8%, from the prior year costs. The decrease was primarily the result of a 13.3% decrease in the average cost of natural gas per KWH generated, a change in the source of generation to be more heavily weighted to lower cost, natural gas-fired generation, and a 10.5% decrease in KWHs generated as a result of lower demand. These decreases were partially offset by a 52.2% increase in KWHs purchased.

Purchased Power – Non-Affiliates

Purchased power expense from non-affiliates was $51.4 million in 2012, an increase of $2.5 million, or 5.2%, from the prior year. The increase was due to a $2.7 million increase in energy costs, partially offset by a $0.2 million decrease in capacity costs. The increase in energy costs was due to an increase in the volume of KWHs purchased, partially offset by a lower average cost per KWH. In 2011, purchased power expense from non-affiliates was $48.9 million, an increase of $7.6 million, or 18.4%, from the prior year. The increase was due to a $7.2 million increase in energy costs and a $0.4 million increase in capacity costs.

Energy purchases from non-affiliates will vary depending on the market prices of wholesale energy as compared to the cost of the Southern Company system's generation, demand for energy within the Southern Company system's service territory, and the availability of the Southern Company system's generation.

Purchased Power – Affiliates

Purchased power expense from affiliates was $22.7 million in 2012, a decrease of $18.9 million, or 45.5%, from the prior year. The decrease was due to a $19.1 million decrease in energy costs, partially offset by a $0.2 million increase in capacity costs. The decrease in energy costs was due to a decrease in the volume of KWHs purchased and a lower cost per KWH purchased. In 2011, purchased power expense from affiliates was $41.6 million, a decrease of $14.3 million, or 25.6%, from the prior year. The decrease was due to decreases of $9.0 million in energy costs and $5.3 million in capacity costs.

Energy purchases from affiliates will vary depending on demand and the availability and cost of generating resources at each company within the Southern Company system. These purchases are made in accordance with the IIC or other contractual agreements, all as approved by the FERC.

Other Operations and Maintenance Expenses

In 2012, other operations and maintenance expenses increased $2.8 million, or 0.9%, compared to the prior year primarily due to increases of $6.2 million in marketing programs and $3.0 million for transmission service related to a third party power purchase agreement (PPA), partially offset by a $6.9 million decrease in routine and planned outage maintenance expense at generation facilities. The increased expense from transmission service did not have a significant impact on earnings since the expense was offset by purchased power capacity revenues through the Company's purchased power capacity recovery clause. The increased expense from marketing programs did not have a significant impact on earnings since the expense was offset by energy conservation revenues through the Company's energy conservation cost recovery clause. In 2011, other operations and maintenance expenses increased $30.7 million, or 11.0%, compared to the prior year primarily due to increases of $13.9 million in routine and planned outage maintenance expense at generation facilities, $3.2 million in other energy services, $10.4 million in labor expense, and $2.1 million in marketing programs. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Cost Recovery Clauses – Purchased Power Capacity Recovery" and "–Energy Conservation Cost Recovery" herein and Note 1 to the financial statements under "Affiliate Transactions" for additional information.

Depreciation and Amortization

Depreciation and amortization increased $11.4 million, or 8.8%, in 2012 compared to the prior year primarily due to the addition of environmental control projects at generation facilities and other net additions to transmission and distribution facilities. Depreciation and amortization increased $8.2 million, or 6.7%, in 2011 compared to the prior year primarily due to the addition of environmental control projects at generation facilities and other net additions to transmission and distribution facilities.

Taxes Other Than Income Taxes

Taxes other than income taxes decreased $3.9 million, or 3.9%, in 2012 compared to the prior year primarily due to a $6.1 million decrease in gross receipts taxes and franchise fees, partially offset by a $1.3 million increase in property taxes and a $0.7 million increase in payroll taxes. Taxes other than income taxes decreased $0.5 million, or 0.5%, in 2011 compared to the prior year primarily due to a $1.1 million decrease in gross receipts taxes, partially offset by a $0.7 million increase in property taxes. Gross receipts taxes and franchise fees have no impact on net income.

Allowance for Funds Used During Construction Equity

Allowance for funds used during construction (AFUDC) equity decreased $4.7 million, or 47.3%, in 2012 compared to the prior year primarily due to an adjustment related to deferred future generation carrying costs and the completion of construction projects related to environmental control projects at generation facilities. AFUDC equity increased $2.7 million, or 37.4%, in 2011 compared to the prior year primarily due to construction of environmental control projects at generation facilities. See Note 1 to the financial statements under "Allowance for Funds Used During Construction" for additional information.

Interest Expense, Net of Amounts Capitalized

Interest expense, net of amounts capitalized increased $2.1 million, or 3.6%, in 2012 compared to the prior year primarily due to increases in long-term debt levels. Interest expense, net of amounts capitalized increased $6.3 million, or 12.0%, in 2011 compared to the prior year primarily due to increases in long-term debt levels resulting from the issuance of additional senior notes in 2011. The increase was partially offset as a result of an increase in capitalization of AFUDC debt related to the construction of environmental control projects.

Income Taxes

Income taxes increased $17.9 million, or 29.3%, in 2012 compared to the prior year primarily due to higher pre-tax earnings, a reduction in the tax benefits associated with a decrease in AFUDC equity, which is non-taxable, and a decrease in state tax credits. Income taxes decreased $10.2 million, or 14.3%, in 2011 compared to the prior year primarily due to lower pre-tax earnings. See Note 5 to the financial statements under "Effective Tax Rate" for additional information.

Effects of Inflation

The Company is subject to rate regulation that is generally based on the recovery of historical and projected costs. The effects of inflation can create an economic loss since the recovery of costs could be in dollars that have less purchasing power. Any adverse effect of inflation on the Company's results of operations has not been substantial in recent years.

FUTURE EARNINGS POTENTIAL

General

The Company operates as a vertically integrated utility providing electricity to retail customers within its traditional service area located in northwest Florida and to wholesale customers in the Southeast. Prices for electricity provided by the Company to retail customers are set by the Florida PSC under cost-based regulatory principles. Prices for wholesale electricity sales, interconnecting transmission lines, and the exchange of electric power are regulated by the FERC. Retail rates and earnings are reviewed and may be adjusted periodically within certain limitations. See ACCOUNTING POLICIES – "Application of Critical Accounting Policies and Estimates – Electric Utility Regulation" herein and Note 3 to the financial statements under "Retail Regulatory Matters" for additional information about regulatory matters.

The results of operations for the past three years are not necessarily indicative of future earnings potential. The level of the Company's future earnings depends on numerous factors that affect the opportunities, challenges, and risks of the Company's business of selling electricity. These factors include the Company's ability to maintain a constructive regulatory environment that continues to allow for the timely recovery of prudently-incurred costs during a time of increasing costs. Future earnings in the near term will depend, in part, upon maintaining energy sales which is subject to a number of factors. These factors include weather, competition, new energy contracts with neighboring utilities, energy conservation practiced by customers, the price of electricity, the price elasticity of demand, and the rate of economic growth or decline in the Company's service territory. Changes in economic conditions impact sales for the Company, and the pace of the economic recovery remains uncertain. The timing and extent of the economic recovery will impact growth and may impact future earnings.

Environmental Matters

Compliance costs related to federal and state environmental statutes and regulations could affect earnings if such costs cannot continue to be fully recovered in rates on a timely basis. Environmental compliance spending over the next several years may differ materially from the amounts estimated. The timing, specific requirements, and estimated costs could change as environmental statutes and regulations are adopted or modified. Further, higher costs that are recovered through regulated rates could contribute to reduced demand for electricity, which could negatively affect results of operations, cash flows, and financial condition. See Note 3 to the financial statements under "Environmental Matters" for additional information.

New Source Review Actions

In 1999, the Environmental Protection Agency (EPA) brought a civil action in the U.S. District Court for the Northern District of Georgia against certain Southern Company subsidiaries, including Alabama Power Company (Alabama Power) and Georgia Power Company (Georgia Power), alleging that these subsidiaries had violated the New Source Review (NSR) provisions of the Clean Air Act and related state laws at certain coal-fired generating facilities. The EPA alleged NSR violations at five coal-fired generating facilities operated by Alabama Power and three coal-fired generating facilities operated by Georgia Power, including a unit co-owned by the Company. The civil action sought penalties and injunctive relief, including an order requiring installation of the best available control technology at the affected units. These actions were filed concurrently with the issuance of notices of violation of the NSR provisions to the Company with respect to the Company's Plant Crist. The case against Georgia Power

(including claims related to the unit co-owned by the Company) was administratively closed in 2001 and has not been reopened. After Alabama Power was dismissed from the original action, the EPA filed a separate action in 2001 against Alabama Power in the U.S. District Court for the Northern District of Alabama.

The Company believes it complied with applicable laws and regulations in effect at the time the work in question took place. The Clean Air Act authorizes maximum civil penalties of $25,000 to $37,500 per day, per violation, depending on the date of the alleged violation. An adverse outcome could require substantial capital expenditures that cannot be determined at this time and could possibly require payment of substantial penalties. Such expenditures could affect future results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates. The ultimate outcome of this matter cannot be determined at this time.

Climate Change Litigation

Kivalina Case

In 2008, the Native Village of Kivalina and the City of Kivalina filed a lawsuit in the U.S. District Court for the Northern District of California against several electric utilities (including Southern Company), several oil companies, and a coal company. The plaintiffs allege that the village is being destroyed by erosion allegedly caused by global warming that the plaintiffs attribute to emissions of greenhouse gases by the defendants. The plaintiffs assert claims for public and private nuisance and contend that some of the defendants (including Southern Company) acted in concert and are therefore jointly and severally liable for the plaintiffs' damages. The suit seeks damages for lost property values and for the cost of relocating the village, which is alleged to be $95 million to $400 million. In 2009, the U.S. District Court for the Northern District of California granted the defendants' motions to dismiss the case. On September 21, 2012, the U.S. Court of Appeals for the Ninth Circuit upheld the U.S. District Court for the Northern District of California's dismissal of the case. On November 27, 2012, the U.S. Court of Appeals for the Ninth Circuit denied the plaintiffs' request for review of the decision. On February 25, 2013, the plaintiffs filed a petition for writ of certiorari with the U.S. Supreme Court. Southern Company believes that these claims are without merit. The ultimate outcome of this matter cannot be determined at this time.

Hurricane Katrina Case

In 2005, immediately following Hurricane Katrina, a lawsuit was filed in the U.S. District Court for the Southern District of Mississippi by Ned Comer on behalf of Mississippi residents seeking recovery for property damage and personal injuries caused by Hurricane Katrina. In 2006, the plaintiffs amended the complaint to include Southern Company and many other electric utilities, oil companies, chemical companies, and coal producers. The plaintiffs allege that the defendants contributed to climate change, which contributed to the intensity of Hurricane Katrina. In 2007, the U.S. District Court for the Southern District of Mississippi dismissed the case. On appeal to the U.S. Court of Appeals for the Fifth Circuit, a three-judge panel reversed the U.S. District Court for the Southern District of Mississippi, holding that the case could proceed, but on rehearing, the full U.S. Court of Appeals for the Fifth Circuit dismissed the plaintiffs' appeal, resulting in reinstatement of the decision of the U.S. District Court for the Southern District of Mississippi in favor of the defendants. In May 2011, the plaintiffs filed an amended version of their class action complaint, arguing that the earlier dismissal was on procedural grounds and under Mississippi law the plaintiffs have a right to re-file. The amended complaint was also filed against numerous chemical, coal, oil, and utility companies, including the Company. On March 20, 2012, the U.S. District Court for the Southern District of Mississippi dismissed the plaintiffs' amended complaint. On April 16, 2012, the plaintiffs appealed the case to the U.S. Court of Appeals for the Fifth Circuit. The Company believes that these claims are without merit. The ultimate outcome of this matter cannot be determined at this time.

Environmental Statutes and Regulations

General

The Company's operations are subject to extensive regulation by state and federal environmental agencies under a variety of statutes and regulations governing environmental media, including air, water, and land resources. Applicable statutes include the Clean Air Act; the Clean Water Act; the Comprehensive Environmental Response, Compensation, and Liability Act; the Resource Conservation and Recovery Act; the Toxic Substances Control Act; the Emergency Planning & Community Right-to-Know Act; the Endangered Species Act; and related federal and state regulations. Compliance with these environmental requirements involves significant capital and operating costs, a major portion of which is expected to be recovered through existing ratemaking provisions. Through 2012, the Company had invested approximately $1.4 billion in environmental capital retrofit projects to comply with these requirements, with annual totals of approximately $70 million, $141 million, and $136 million for 2012, 2011, and 2010, respectively. The Company expects that base level capital expenditures to comply with existing statutes and regulations, including capital expenditures and compliance costs associated with the EPA's final Mercury and Air Toxics Standards (MATS) rule, will be a total of approximately $644 million from 2013 through 2015, with annual totals of approximately $158 million, $319 million, and $167 million for 2013, 2014, and 2015, respectively.

The Company continues to monitor the development of the EPA's proposed water and coal combustion byproducts rules and to evaluate compliance options. See FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" herein for the Company's anticipated incremental compliance costs related to the proposed water and coal combustion byproducts rules for 2013 through 2015. The ultimate capital expenditures and compliance costs with respect to these proposed rules, including additional expenditures required after 2015, will be dependent on the requirements of the final rules and regulations adopted by the EPA and the outcome of any legal challenges to these rules. See "Water Quality" and "Coal Combustion Byproducts" herein for additional information.

The Company's ultimate environmental compliance strategy, including potential unit retirement and replacement decisions and future environmental capital expenditures will be affected by the final requirements of new or revised environmental regulations and regulations relating to global climate change that are promulgated, including the proposed environmental regulations described below; the outcome of any legal challenges to the environmental rules; the cost, availability, and existing inventory of emissions allowances; and the Company's fuel mix. Compliance costs may arise from existing unit retirements, installation of additional environmental controls, upgrades to the transmission system, and adding or changing fuel sources for certain existing units. The ultimate outcome of these matters cannot be determined at this time.

The State of Florida has statutory provisions that allow a utility to petition the Florida PSC for recovery of prudent environmental compliance costs that are not being recovered through base rates or any other recovery mechanism. The environmental cost recovery mechanism in Florida is discussed in Note 3 to the financial statements under "Retail Regulatory Matters – Environmental Cost Recovery." Substantially all of the costs for the Clean Air Act and other new environmental legislation discussed below are expected to be recovered through the environmental cost recovery clause.

Compliance with any new federal or state legislation or regulations relating to air quality, water, coal combustion byproducts, global climate change, or other environmental and health concerns could significantly affect the Company. Although new or revised environmental legislation or regulations could affect many areas of the Company's operations, the full impact of any such changes cannot be determined at this time. Additionally, many of the Company's commercial and industrial customers may also be affected by existing and future environmental requirements, which for some may have the potential to ultimately affect their demand for electricity.

Air Quality

Compliance with the Clean Air Act and resulting regulations has been and will continue to be a significant focus for the Company. Since 1990, the Company has spent approximately $1.1 billion in reducing and monitoring emissions pursuant to the Clean Air Act. Additional controls are currently planned or under consideration to further reduce air emissions, maintain compliance with existing regulations, and meet new requirements.

The EPA regulates ground level ozone concentrations through implementation of an eight-hour ozone air quality standard. In 2008, the EPA adopted a more stringent eight-hour ozone National Ambient Air Quality Standard, which it began to implement in September 2011. On May 21, 2012, the EPA published its final determination of nonattainment areas based on the 2008 eight-hour ozone air quality standards. No areas within the Company's service territory were determined to be in nonattainment of this standard.

The EPA regulates fine particulate matter concentrations on an annual and 24-hour average basis. All areas within the Company's service territory have achieved attainment with the 1997 and 2006 particulate matter National Ambient Air Quality Standards. On January 15, 2013, the EPA published a final rule that increases the stringency of the annual fine particulate matter standard. The new standard could result in the designation of new nonattainment areas within the Company's service territory.

Final revisions to the National Ambient Air Quality Standard for sulfur dioxide (SO_2), including the establishment of a new one-hour standard, became effective in 2010. The EPA plans to issue area designations under this new standard in June 2013, and areas within the Company's service territory could ultimately be designated as nonattainment. Implementation of the revised SO_2 standard could require additional reductions in SO_2 emissions and increased compliance and operational costs.

Revisions to the National Ambient Air Quality Standard for nitrogen dioxide (NO_2), which established a new one-hour standard, became effective in 2010. On February 29, 2012, the new NO_2 standard became effective. The EPA designated the entire country as "unclassifiable/attainment" under the new standard, with no nonattainment areas designated. However, the new NO_2 standard could result in significant additional compliance and operational costs for units that require new source permitting.

The Company's service territory is subject to the requirements of the Clean Air Interstate Rule (CAIR), which calls for phased reductions in SO_2 and nitrogen oxide (NO_x) emissions from power plants in 28 eastern states. In 2008, the U.S. Court of Appeals for the District of Columbia Circuit issued decisions invalidating CAIR, but left CAIR compliance requirements in place while the EPA developed a new rule. In August 2011, the EPA adopted the Cross State Air Pollution Rule (CSAPR) to replace CAIR effective January 1, 2012. However, in December 2011, the U. S. Court of Appeals for the District of Columbia Circuit stayed the rule and, on August 21, 2012, vacated CSAPR in its entirety and directed the EPA to continue to administer CAIR pending the EPA's development of a valid replacement. On January 24, 2013, the U.S. Court of Appeals for the District of Columbia Circuit denied requests by the EPA and other parties for rehearing.

The EPA finalized the Clean Air Visibility Rule (CAVR) in 2005, with a goal of restoring natural visibility conditions in certain areas (primarily national parks and wilderness areas) by 2064. The rule involves the application of best available retrofit technology (BART) to certain sources built between 1962 and 1977 and any additional emissions reductions necessary for each designated area to achieve reasonable progress toward the natural visibility conditions goal by 2018 and for each 10-year period thereafter. In 2005, the EPA determined that compliance with CAIR satisfies BART obligations under CAVR, but, on June 7, 2012, the EPA issued a final rule replacing CAIR with CSAPR as an alternative means of satisfying BART obligations. The vacatur of CSAPR creates additional uncertainty with respect to whether additional controls may be required for CAVR and BART compliance.

On February 16, 2012, the EPA published the final MATS rule, which imposes stringent emissions limits for acid gases, mercury, and particulate matter on coal- and oil-fired electric utility steam generating units. Compliance for existing sources is required by April 16, 2015, unless a one-year compliance extension is granted by the state or local air permitting agency. Mississippi Power Company (Mississippi Power) has received this one-year extension for Plant Daniel to April 16, 2016.

Numerous petitions for administrative reconsideration of the MATS rule, including a petition by the Company, have been filed with the EPA. On November 30, 2012, the EPA proposed a reconsideration of certain new source and startup/shutdown issues. The EPA plans to complete its reconsideration rulemaking by March 2013. Challenges to the final rule have also been filed in the U.S. District Court for the District of Columbia by numerous states, environmental organizations, industry groups, and others.

On August 29, 2012, the EPA published proposed revisions to the New Source Performance Standard (NSPS) for Stationary Combustion Turbines (CTs). If finalized as proposed, the revisions would apply the NSPS to all new, reconstructed, and modified CTs (including CTs at combined cycle units), during all periods of operation, including startup and shutdown, and alter the criteria for determining when an existing CT has been reconstructed.

On February 12, 2013, the EPA proposed a rule that would require certain states to revise the provisions of their State Implementation Plans (SIPs) relating to the regulation of excess emissions at industrial facilities, including fossil fuel-fired generating facilities, during periods of startup, shut-down, or malfunction (SSM). The EPA proposes a determination that the SSM provisions in the SIPs for 36 states (including Florida, Georgia, and Mississippi) do not meet the requirements of the Clean Air Act and must be revised within 18 months of the date on which the EPA publishes the final rule. If finalized as proposed, this new requirement could result in significant additional compliance and operational costs.

The Company has developed and continually updates a comprehensive environmental compliance strategy to assess compliance obligations associated with the existing and new environmental requirements discussed above. The impacts of the eight-hour ozone, fine particulate matter, SO_2 and NO_2 standards, CAIR and any future replacement rule, CAVR, the MATS rule, the NSPS for CTs, and the SSM rule on the Company cannot be determined at this time and will depend on the specific provisions of recently finalized and future rules, the resolution of pending and future legal challenges, and the development and implementation

of rules at the state level. These regulations could result in significant additional compliance costs that could affect future unit retirement and replacement decisions and results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates. Further, higher costs that are recovered through regulated rates could contribute to reduced demand for electricity, which could negatively impact results of operations, cash flows, and financial condition. In addition, certain units in the State of Georgia, including Plant Scherer Unit 3, which is co-owned by the Company, are required to install specific emissions controls according to a schedule set forth in the state's Multi-Pollutant Rule, which is designed to reduce emissions of SO_2, NO_x, and mercury.

See Note 3 to the financial statements under "Retail Regulatory Matters – Environmental Cost Recovery" for discussion of the State of Florida's statutory provisions on environmental cost recovery.

Water Quality

In April 2011, the EPA published a proposed rule that establishes standards for reducing effects on fish and other aquatic life caused by cooling water intake structures at existing power plants and manufacturing facilities. The rule also addresses cooling water intake structures for new units at existing facilities. Compliance with the proposed rule could require changes to existing cooling water intake structures at certain of the Company's generating facilities, and new generating units constructed at existing plants would be required to install closed cycle cooling towers. The EPA has entered into an amended settlement agreement to extend the deadline for issuing a final rule until June 27, 2013. If finalized as proposed, some of the Company's facilities may be subject to significant additional capital expenditures and compliance costs that could affect future unit retirement and replacement decisions. Also, results of operations, cash flows, and financial condition could be significantly impacted if such costs are not recovered through regulated rates. The ultimate outcome of this rulemaking will depend on the final rule and the outcome of any legal challenges and cannot be determined at this time.

The EPA has announced its determination that revision of the current effluent guidelines for steam electric power plants is warranted and has stated that it intends to propose such revisions by April 2013 and finalize the revisions by May 2014. New advanced wastewater treatment requirements are expected and may result in the installation of additional controls on certain of the Company's facilities, which could result in significant additional capital expenditures and compliance costs that could affect future unit retirement and replacement decisions. The impact of the revised guidelines will depend on the specific technology requirements of the final rule and, therefore, cannot be determined at this time.

In addition, the State of Florida is finalizing numeric nutrient water quality standards to limit the amount of nitrogen and phosphorous allowed in state waters. The impact of these standards will depend on the specific requirements of the final rule and cannot be determined at this time. See FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" for additional information regarding estimated compliance costs for 2013 through 2015. See also Note 3 to the financial statements under "Retail Regulatory Matters – Environmental Cost Recovery" for discussion of the State of Florida's statutory provisions on environmental cost recovery.

Coal Combustion Byproducts

The Company currently operates three electric generating plants in Florida and is part owner of units at generating plants located in Mississippi and Georgia operated by the respective unit's co-owner with on-site coal combustion byproducts storage facilities. In addition to on-site storage, the Company sells a portion of its coal combustion byproducts to third parties for beneficial reuse. Historically, individual states have regulated coal combustion byproducts and the States of Florida, Georgia, and Mississippi each has its own regulatory parameters. The Company has a routine and robust inspection program in place to ensure the integrity of its coal ash surface impoundments and compliance with applicable regulations.

The EPA continues to evaluate the regulatory program for coal combustion byproducts, including coal ash and gypsum, under federal solid and hazardous waste laws. In 2010, the EPA published a proposed rule that requested comments on two potential regulatory options for the management and disposal of coal combustion byproducts: regulation as a solid waste or regulation as if the materials technically constituted a hazardous waste. Adoption of either option could require closure of, or significant change to, existing storage facilities and construction of lined landfills, as well as additional waste management and groundwater monitoring requirements. Under both options, the EPA proposes to exempt the beneficial reuse of coal combustion byproducts from regulation; however, a hazardous or other designation indicative of heightened risk could limit or eliminate beneficial reuse options. Environmental groups and other parties have filed lawsuits in the U.S. District Court for the District of Columbia seeking to require the EPA to complete its rulemaking process and issue final regulations pertaining to the regulation of coal combustion byproducts.

While the ultimate outcome of this matter cannot be determined at this time and will depend on the final form of any rules adopted and the outcome of any legal challenges, additional regulation of coal combustion byproducts could have a material impact on the generation, management, beneficial use, and disposal of such byproducts. Any material changes are likely to result in substantial additional compliance, operational, and capital costs that could affect future unit retirement and replacement decisions. Moreover, the Company could incur additional material asset retirement obligations with respect to closing existing storage facilities. The Company's results of operations, cash flows, and financial condition could be significantly impacted if such costs are not recovered through regulated rates. Further, higher costs that are recovered through regulated rates could contribute to reduced demand for electricity, which could negatively impact results of operations, cash flows, and financial condition. See FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" herein for additional information regarding estimated compliance costs for 2013 through 2015. See also Note 3 to the Financial Statements under "Retail Regulatory Matters – Environmental Cost Recovery" for discussion of the State of Florida's statutory provisions on environmental cost recovery.

Environmental Remediation

The Company must comply with other environmental laws and regulations that cover the handling and disposal of waste and releases of hazardous substances. Under these various laws and regulations, the Company may also incur substantial costs to clean up properties. The Company conducts studies to determine the extent of any required cleanup and has recognized in its financial statements the costs to clean up known impacted sites. Included in this amount are costs associated with remediation of the Company's substation sites. These projects have been approved by the Florida PSC for recovery through the environmental cost recovery clause; therefore, there is no impact to the Company's net income as a result of these liabilities. The Company may be liable for some or all required cleanup costs for additional sites that may require environmental remediation. See Note 3 to the financial statements under "Environmental Matters – Environmental Remediation" for additional information.

Global Climate Issues

The EPA currently regulates greenhouse gases under the Prevention of Significant Deterioration and Title V operating permit programs of the Clean Air Act. In addition, over the past several years, the U.S. Congress has considered many proposals to reduce greenhouse gas emissions, mandate renewable or clean energy, and impose energy efficiency standards. Such proposals are expected to continue to be considered by the U.S. Congress. International climate change negotiations under the United Nations Framework Convention on Climate Change are also continuing.

On April 13, 2012, the EPA published proposed regulations to establish standards of performance for greenhouse gas emissions from new fossil fuel steam electric generating units. The EPA has also announced plans to develop federal guidelines for states to establish greenhouse gas emissions performance standards for existing sources. The impact of this rulemaking will depend on the scope and specific requirements of the final rule and the outcome of any legal challenges and, therefore, cannot be determined at this time.

Although the outcome of federal, state, and international initiatives cannot be determined at this time, additional restrictions on the Company's greenhouse gas emissions or requirements relating to renewable energy or energy efficiency at the federal or state level could result in significant additional compliance costs, including capital expenditures. These costs could affect future unit retirement and replacement decisions and could result in the retirement of a significant number of coal-fired generating units. See Item 1 – BUSINESS – "Rate Matters – Integrated Resource Planning" of the Form 10-K for additional information.

Also, additional compliance costs and costs related to unit retirements could affect results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates. Further, higher costs that are recovered through regulated rates could contribute to reduced demand for electricity, which could negatively impact results of operations, cash flows, and financial condition. See Note 3 to the financial statements under "Retail Regulatory Matters – Environmental Cost Recovery" for discussion of the State of Florida's statutory provisions on environmental cost recovery.

The EPA's greenhouse gas reporting rule requires annual reporting of carbon dioxide equivalent emissions in metric tons for a company's operational control of facilities. Based on ownership or financial control of facilities, the Company reported 2011 greenhouse gas emissions of approximately 11 million metric tons of carbon dioxide equivalent. The preliminary estimate of the Company's 2012 greenhouse gas emissions on the same basis is approximately 8 million metric tons of carbon dioxide equivalent. The level of greenhouse gas emissions from year to year will depend on the level of generation and mix of fuel sources, which is determined primarily by demand, the unit cost of fuel consumed, and the availability of generating units.

PSC Matters

The Company's rates and charges for service to retail customers are subject to the regulatory oversight of the Florida PSC. The Company's rates are a combination of base rates and several separate cost recovery clauses for specific categories of costs. These

separate cost recovery clauses address such items as fuel and purchased energy costs, purchased power capacity costs, energy conservation and demand side management programs, and the costs of compliance with environmental laws and regulations. Costs not addressed through one of the specific cost recovery clauses are recovered through the Company's base rates.

Retail Base Rate Case

On March 12, 2012, the Florida PSC approved an increase in retail base rates and charges of $64 million effective April 11, 2012. The amount of the increase includes the previously approved $38.5 million interim retail rate increase implemented in September 2011. The Florida PSC's decision on the amount of the increase also included a determination that none of the base rate revenues collected on an interim basis would be refunded. The Company's authorized retail ROE is a range of 9.25% to 11.25% with new retail base rates set at the midpoint retail ROE of 10.25%. In addition, the Florida PSC also approved a step increase to the Company's retail base rates and charges of $4 million effective in January 2013.

Cost Recovery Clauses

On November 5, 2012, the Florida PSC approved the Company's annual rate clause requests for its fuel, purchased power capacity, conservation, and environmental compliance cost recovery factors for 2013. The net effect of the approved changes is a 1.9% rate increase for residential customers using 1,000 KWHs per month.

Revenues for all cost recovery clauses, as recorded on the financial statements, are adjusted for differences in actual recoverable costs and amounts billed in current regulated rates. Accordingly, changes in the billing factor for fuel and purchased power will have no significant effect on the Company's revenues or net income, but will affect annual cash flow. The recovery provisions for environmental compliance and energy conservation include related expenses and a return on net average investment. See Notes 1 and 3 to the financial statements under "Revenues" and "Retail Regulatory Matters" respectively, for additional information.

Fuel Cost Recovery

The Company has established fuel cost recovery rates as approved by the Florida PSC. If, at any time during the year, the projected year-end fuel cost over or under recovery balance exceeds 10% of the projected fuel revenue applicable for the period, the Company is required to notify the Florida PSC and indicate if an adjustment to the fuel cost recovery factor is being requested. On February 14, 2012, the Florida PSC approved a reduction to the fuel cost recovery factors starting in March 2012. The effect of the approved change was a 2.7% decrease for residential customers using 1,000 KWHs per month. On June 19, 2012, the Florida PSC approved an additional decrease in the Company's fuel rates lowering the 1,000 KWH residential bill 7.8% to reduce annual billings by approximately $58.8 million effective July 2, 2012.

The increase in the fuel cost over recovered balance during 2012 was primarily due to lower than expected fuel costs and purchased power energy expenses. At December 31, 2012 and 2011, the over recovered fuel balance was approximately $17.1 million and $9.9 million, respectively, which is included in other regulatory liabilities, current in the balance sheets. See Note 1 to the financial statements under "Fuel Costs" and "Fuel Inventory" for additional information.

Purchased Power Capacity Recovery

The Company has established purchased power capacity recovery cost rates as approved by the Florida PSC. If the projected year-end purchased power capacity cost over or under recovery balance exceeds 10% of the projected purchased power capacity revenue applicable for the period, the Company is required to notify the Florida PSC and indicate if an adjustment to the purchased power capacity cost recovery factor is being requested.

At December 31, 2012, the Company had an under recovered purchased power capacity balance of approximately $0.8 million, which is included in under recovered regulatory clause revenues in the balance sheets. At December 31, 2011, the Company had an over recovered purchased power capacity balance of approximately $8.0 million, which is included in other regulatory liabilities, current in the balance sheets. See Note 7 to the financial statements under "Fuel and Purchased Power Commitments" for additional information.

Environmental Cost Recovery

The Florida Legislature adopted legislation for an environmental cost recovery clause, which allows an electric utility to petition the Florida PSC for recovery of prudent environmental compliance costs that are not being recovered through base rates or any other recovery mechanism. Such environmental costs include operations and maintenance expenses, emissions allowance expense, depreciation, and a return on net average investment. This legislation also allows recovery of costs incurred as a result of an agreement between the Company and the Florida Department of Environmental Protection for the purpose of ensuring compliance with ozone ambient air quality standards adopted by the EPA.

In 2007, the Florida PSC voted to approve a stipulation among the Company, the Office of Public Counsel, and the Florida Industrial Power Users Group regarding the Company's plan for complying with certain federal and state regulations addressing air quality. The Company's environmental compliance plan as filed in 2007 contemplated implementation of specific projects identified in the plan from 2007 through 2018. The stipulation covers all elements of the original plan that were committed for implementation at the time of the stipulation. The Florida PSC's approval of the stipulation also required the Company to file annual updates to the plan and outlined a process for approval of additional elements in the plan when they became committed projects. In the 2010 update filing, the Company identified several elements of the updated plan that the Company had decided to implement. Following the process outlined in the original approved stipulation, these additional projects were approved by the Florida PSC later in 2010. The Florida PSC acknowledged that the costs of the approved projects associated with the Company's CAIR and CAVR compliance plans are eligible for recovery through the environmental cost recovery clause.

Annually, the Company seeks recovery of projected costs including any true-up amounts from prior periods. At December 31, 2012, the under recovered environmental balance was approximately $1.9 million, which is included in under recovered regulatory clause revenues in the balance sheets. At December 31, 2011, the over recovered environmental balance was approximately $10.0 million, which is included in other regulatory liabilities, current in the balance sheets. See FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" herein for additional information.

On April 3, 2012, the Mississippi PSC approved Mississippi Power's request for a certificate of public convenience and necessity to construct a flue gas desulfurization system (scrubber) on Plant Daniel Units 1 and 2. On May 3, 2012, the Sierra Club filed a notice of appeal of the order with the Chancery Court of Harrison County, Mississippi. These units are jointly owned by Mississippi Power and the Company, with 50% ownership each. The estimated total cost of the project is approximately $660 million, excluding AFUDC, and it is scheduled for completion in December 2015. The Company's portion of the cost is expected to be recovered through the environmental cost recovery clause. The ultimate outcome of this matter cannot be determined at this time.

Energy Conservation Cost Recovery

Every five years, the Florida PSC establishes new numeric conservation goals covering a 10-year period for utilities to reduce annual energy and seasonal peak demand using demand-side management (DSM) programs. After the goals are established, utilities develop plans and programs to meet the approved goals. The costs for these programs are recovered through rates established annually in the energy conservation cost recovery (ECCR) clause.

The most recent goal setting process established new DSM goals for the period 2010 through 2019. The new goals are significantly higher than the goals established in the previous five-year cycle due to a change in the cost-effectiveness test on which the Florida PSC relies to set the goals. The DSM program standards were approved in April 2011, which allow the Company to implement its DSM programs designed to meet the new goals. Several of these new programs were implemented in June 2011 and the costs related to these programs are reflected in the 2012 ECCR factor approved by the Florida PSC. Higher cost recovery rates and achievement of the new DSM goals may result in reduced sales of electricity which could negatively impact results of operations, cash flows, and financial condition if base rates cannot be adjusted on a timely basis.

See BUSINESS under "Rate Matters – Integrated Resource Planning – Gulf Power" in Item 1 for a discussion of the Company's 10-year site plan filed on an annual basis with the Florida PSC.

At December 31, 2012 and 2011, the under recovered energy conservation balance was approximately $0.8 million and $3.1 million, respectively, which is included in under recovered regulatory clause revenues in the balance sheets.

Income Tax Matters

Bonus Depreciation

In 2010, the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010 (Tax Relief Act) was signed into law. Major tax incentives in the Tax Relief Act include 100% bonus depreciation for property placed in service after September 8, 2010 and through 2011 (and for certain long-term production-period projects placed in service in 2012) and 50% bonus depreciation for property placed in service in 2012 (and for certain long-term production-period projects to be placed in service in 2013), which will have a positive impact on the future cash flows of the Company through 2013.

On January 2, 2013, the American Taxpayer Relief Act of 2012 (ATRA) was signed into law. The ATRA retroactively extended several tax credits through 2013 and extended 50% bonus depreciation for property to be placed in service in 2013 (and for certain long-term production-period projects to be placed in service in 2014). The extension of 50% bonus depreciation will have a positive impact on the future cash flows of the Company through 2014.

Consequently, the Company's positive cash flow benefit is estimated to be between $30 million and $35 million in 2013.

Other Matters

The Company is involved in various other matters being litigated and regulatory matters that could affect future earnings. In addition, the Company is subject to certain claims and legal actions arising in the ordinary course of business. The Company's business activities are subject to extensive governmental regulation related to public health and the environment, such as regulation of air emissions and water discharges. Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements, such as air quality and water standards, has increased generally throughout the U.S. In particular, personal injury, property damage, and other claims for damages alleged to have been caused by carbon dioxide and other emissions, coal combustion byproducts, and alleged exposure to hazardous materials, and/or requests for injunctive relief in connection with such matters, have become more frequent. The ultimate outcome of such pending or potential litigation against the Company cannot be predicted at this time; however, for current proceedings not specifically reported herein or in Note 3 to the financial statements, management does not anticipate that the ultimate liabilities, if any, arising from such current proceedings would have a material effect on the Company's financial statements. See Note 3 to the financial statements for a discussion of various other contingencies, regulatory matters, and other matters being litigated which may affect future earnings potential.

ACCOUNTING POLICIES

Application of Critical Accounting Policies and Estimates

The Company prepares its financial statements in accordance with generally accepted accounting principles (GAAP). Significant accounting policies are described in Note 1 to the financial statements. In the application of these policies, certain estimates are made that may have a material impact on the Company's results of operations and related disclosures. Different assumptions and measurements could produce estimates that are significantly different from those recorded in the financial statements. Senior management has reviewed and discussed the following critical accounting policies and estimates with the Audit Committee of Southern Company's Board of Directors.

Electric Utility Regulation

The Company is subject to retail regulation by the Florida PSC. The Florida PSC sets the rates the Company is permitted to charge customers based on allowable costs. The Company is also subject to cost based regulation by the FERC with respect to wholesale transmission rates. As a result, the Company applies accounting standards which require the financial statements to reflect the effects of rate regulation. Through the ratemaking process, the regulators may require the inclusion of costs or revenues in periods different than when they would be recognized by a non-regulated company. This treatment may result in the deferral of expenses and the recording of related regulatory assets based on anticipated future recovery through rates or the deferral of gains or creation of liabilities and the recording of related regulatory liabilities. The application of the accounting standards has a further effect on the Company's financial statements as a result of the estimates of allowable costs used in the ratemaking process. These estimates may differ from those actually incurred by the Company; therefore, the accounting estimates inherent in specific costs such as depreciation and pension and postretirement benefits have less of a direct impact on the Company's results of operations and financial condition than they would on a non-regulated company.

As reflected in Note 1 to the financial statements, significant regulatory assets and liabilities have been recorded. Management reviews the ultimate recoverability of these regulatory assets and any requirement to refund these regulatory liabilities based on applicable regulatory guidelines and GAAP. However, adverse legislative, judicial, or regulatory actions could materially impact the amounts of such regulatory assets and liabilities and could adversely impact the Company's financial statements.

Contingent Obligations

The Company is subject to a number of federal and state laws and regulations, as well as other factors and conditions that subject it to environmental, litigation, income tax, and other risks. See FUTURE EARNINGS POTENTIAL herein and Note 3 to the financial statements for more information regarding certain of these contingencies. The Company periodically evaluates its exposure to such risks and, in accordance with GAAP, records reserves for those matters where a non-tax-related loss is considered probable and reasonably estimable and records a tax asset or liability if it is more likely than not that a tax position will be sustained. The adequacy of reserves can be significantly affected by external events or conditions that can be unpredictable; thus, the ultimate outcome of such matters could materially affect the Company's financial statements.

Unbilled Revenues

In November 2012, the Company began using automated meter readings to measure unbilled KWH sales for energy delivered through month-end. As of December 31, 2012, measured unbilled KWH sales represented approximately 90% of total unbilled KWH sales. Increased usage of actual data to compute unbilled revenues reduces the impact that estimates could have on the Company's results of operations; therefore, the Company no longer considers unbilled revenue a critical accounting estimate.

Pension and Other Postretirement Benefits

The Company's calculation of pension and other postretirement benefits expense is dependent on a number of assumptions. These assumptions include discount rates, healthcare cost trend rates, expected long-term return on plan assets, mortality rates, expected salary and wage increases, and other factors. Components of pension and other postretirement benefits expense include interest and service cost on the pension and other postretirement benefit plans, expected return on plan assets and amortization of certain unrecognized costs and obligations. Actual results that differ from the assumptions utilized are accumulated and amortized over future periods and, therefore, generally affect recognized expense and the recorded obligation in future periods. While the Company believes that the assumptions used are appropriate, differences in actual experience or significant changes in assumptions would affect its pension and other postretirement benefits costs and obligations.

Key elements in determining the Company's pension and other postretirement benefit expense in accordance with GAAP are the expected long-term return on plan assets and the discount rate used to measure the benefit plan obligations and the periodic benefit plan expense for future periods. The expected long-term return on postretirement benefit plan assets is based on the Company's investment strategy, historical experience, and expectations for long-term rates of return that consider external actuarial advice. The Company determines the long-term return on plan assets by applying the long-term rate of expected returns on various asset classes to the Company's target asset allocation. The Company discounts the future cash flows related to its postretirement benefit plans using a single-point discount rate developed from the weighted average of market-observed yields for high quality fixed income securities with maturities that correspond to expected benefit payments.

A 25 basis point change in any significant assumption (discount rate, salaries, or long-term return on plan assets) would result in a $1.3 million or less change in total annual benefit expense and an $18 million or less change in projected obligations.

FINANCIAL CONDITION AND LIQUIDITY

Overview

The Company's financial condition remained stable at December 31, 2012. The Company's cash requirements primarily consist of funding ongoing operations, common stock dividends, capital expenditures, and debt maturities. Capital expenditures and other investing activities include investments to meet projected long-term demand requirements, to comply with environmental regulations, and for restoration following major storms. Operating cash flows provide a substantial portion of the Company's cash needs. For the three-year period from 2013 through 2015, the Company's projected common stock dividends, capital expenditures, and debt maturities are expected to exceed operating cash flows. Projected capital expenditures in that period are primarily to add environmental equipment for existing generating units and to expand and improve transmission and distribution facilities. The Company plans to finance future cash needs in excess of its operating cash flows primarily through debt and equity issuances. The Company intends to continue to monitor its access to short-term and long-term capital markets as well as its bank credit arrangements to meet future capital and liquidity needs. See "Sources of Capital," "Financing Activities," and "Capital Requirements and Contractual Obligations" herein for additional information.

The Company's investments in the qualified pension plan increased in value as of December 31, 2012 as compared to December 31, 2011. In December 2012, the Company contributed $13.4 million to the qualified pension plan.

Net cash provided from operating activities totaled $419.2 million in 2012, an increase of $43.0 million from 2011, primarily due to an increase in deferred income taxes primarily related to bonus depreciation, partially offset by decreases in the cash provided from prepaid income taxes, fossil fuel stock, and the recovery of fuel costs. Net cash provided from operating activities totaled $376.2 million in 2011, an increase of $108.4 million from 2010, primarily due to increases in the recovery of fuel costs and prepaid income taxes, primarily due to bonus depreciation.

Net cash used for investing activities totaled $348.6 million, $343.5 million, and $308.4 million for 2012, 2011, and 2010, respectively. The changes in cash used for investing activities were primarily due to gross property additions to utility plant of $325.2 million, $337.8 million, and $285.4 million for 2012, 2011, and 2010, respectively. Funds for the Company's property additions were provided by operating activities, capital contributions, and other financing activities.

Net cash used for financing activities totaled $55.8 million and $31.8 million in 2012 and 2011, respectively. Net cash provided from financing activities was $48.4 million in 2010. The 2012 and 2011 decreases in cash from financing activities were primarily due to short-term debt payments, long-term debt redemptions, and payment of common stock dividends, partially offset

by common stock and long-term debt issuances. Fluctuations in cash flow from financing activities vary from year to year based on capital needs and the maturity or redemption of securities.

Significant balance sheet changes in 2012 include an increase of $219.5 million in property, plant, and equipment, primarily due to the addition of environmental control projects at generation facilities, an increase of $190.0 million in accumulated deferred income taxes, primarily related to bonus depreciation, an increase in common stock, without par value due to the issuance of common stock to Southern Company for $40 million and an increase in other regulatory assets, deferred and other deferred credits and liabilities of $49.2 million and $44.2 million, respectively, primarily due to increases in PPAs' deferred capacity expense.

The Company's ratio of common equity to total capitalization, including short-term debt, was 44.5% in 2012 and 43.7% in 2011. See Note 6 to the financial statements for additional information.

Sources of Capital

The Company plans to obtain the funds required for construction and other purposes from sources similar to those used in the past, which were primarily from operating cash flows, short-term debt, security issuances, term loans, and equity contributions from Southern Company. However, the amount, type, and timing of any future financings, if needed, will depend on regulatory approval, prevailing market conditions, and other factors.

Security issuances are subject to annual regulatory approval by the Florida PSC pursuant to its rules and regulations. Additionally, with respect to the public offering of securities, the Company files registration statements with the Securities and Exchange Commission (SEC) under the Securities Act of 1933, as amended (1933 Act). The amounts of securities authorized by the Florida PSC, as well as the amounts, if any, registered under the 1933 Act, are continuously monitored and appropriate filings are made to ensure flexibility in the capital markets.

The Company obtains financing separately without credit support from any affiliate. See Note 6 to the financial statements under "Bank Credit Arrangements" for additional information. The Southern Company system does not maintain a centralized cash or money pool. Therefore, funds of the Company are not commingled with funds of any other company in the Southern Company system.

The Company's current liabilities frequently exceed current assets because of the continued use of short-term debt as a funding source to meet scheduled maturities of long-term debt, as well as cash needs, which can fluctuate significantly due to the seasonality of the business.

At December 31, 2012, the Company had approximately $32.2 million of cash and cash equivalents. Committed credit arrangements with banks at December 31, 2012 were as follows:

Expires[a]				Executable Term-Loans		Due Within One Year	
2013	2014	Total	Unused	One Year	Two Years	Term Out	No Term Out
$80	$195	$275	$275	$45	$—	$45	$35

(a) No credit arrangements expire after 2014.

See Note 6 to the financial statements under "Bank Credit Arrangements" for additional information.

Most of these arrangements contain covenants that limit debt levels and contain cross default provisions that are restricted only to the indebtedness of the Company. The Company is currently in compliance with all such covenants. The Company expects to renew its credit arrangements, as needed, prior to expiration. These credit arrangements provide liquidity support to the Company's variable rate pollution control revenue bonds and commercial paper borrowings. As of December 31, 2012, the Company had $69 million of outstanding pollution control revenue bonds requiring liquidity support. In addition, the Company has substantial cash flow from operating activities and access to the capital markets to meet liquidity needs.

The Company may also meet short-term cash needs through a Southern Company subsidiary organized to issue and sell commercial paper at the request and for the benefit of the Company and the other traditional operating companies. Proceeds from such issuances for the benefit of the Company are loaned directly to the Company. The obligations of each company under these arrangements are several and there is no cross-affiliate credit support.

Details of short-term borrowings were as follows:

	Short-term Debt at the End of the Period [a]		Short-term Debt During the Period [b]		
	Amount Outstanding	Weighted Average Interest Rate	Average Outstanding	Weighted Average Interest Rate	Maximum Amount Outstanding
	(in millions)		*(in millions)*		*(in millions)*
December 31, 2012:					
Commercial paper	$ 124	0.3%	$ 69	0.3%	$ 124
December 31, 2011:					
Commercial paper	$ 111	0.2%	$ 53	0.2%	$ 111
Short-term bank debt	—	N/A	4	1.3%	30
Total	$ 111	0.2%	$ 57	0.3%	
December 31, 2010:					
Commercial paper	$ 92	0.3%	$ 44	0.3%	$ 108

(a) Excludes notes payable related to other energy service contracts of $3.2 million, $3.6 million, and $1.2 million at December 31, 2012, 2011, and 2010, respectively.

(b) Average and maximum amounts are based upon daily balances during the twelve-month periods ended December 31, 2012, 2011, and 2010.

Management believes that the need for working capital can be adequately met by utilizing commercial paper programs, lines of credit, and cash.

Financing Activities

In January 2012, the Company issued to Southern Company 400,000 shares of the Company's common stock, without par value, and realized proceeds of $40 million. Subsequent to December 31, 2012, the Company issued to Southern Company 400,000 shares of the Company's common stock, without par value, and realized proceeds of $40 million. The proceeds were used to repay a portion of the Company's short-term debt and for other general corporate purposes, including the Company's continuous construction program.

In May 2012, the Company issued $100 million aggregate principal amount of Series 2012A 3.10% Senior Notes due May 15, 2022. The net proceeds from the sale of the Series 2012A Senior Notes were used by the Company for the redemption in June 2012 of all of approximately $61 million aggregate principal amount of the Company's Series F 5.60% Senior Insured Quarterly Notes due April 1, 2033 and $30 million aggregate principal amount of the Company's Series H 5.25% Senior Notes due July 15, 2033, to repay a portion of its outstanding short-term indebtedness, and for general corporate purposes, including the Company's continuous construction program.

In November 2012, the Mississippi Business Finance Corporation issued $13 million aggregate principal amount of Mississippi Business Finance Corporation Solid Waste Disposal Facilities Revenue Refunding Bonds, Series 2012 (Gulf Power Company Project), due November 1, 2042 for the benefit of the Company. The proceeds were used to redeem the Mississippi Business Finance Corporation Solid Waste Disposal Facilities Revenue Refunding Bonds, Series 2002 (Gulf Power Company Project) due September 1, 2028.

In addition to any financings that may be necessary to meet capital requirements, contractual obligations, and storm-recovery, the Company plans to continue, when economically feasible, a program to retire higher-cost securities and replace these obligations with lower-cost capital if market conditions permit.

Credit Rating Risk

The Company does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. There are certain contracts that could require collateral, but not accelerated payment, in the event of a credit rating change to BBB- and/or Baa3 or below. These contracts are for physical electricity purchases and sales, fuel transportation and storage, and energy price risk management. The maximum potential collateral requirements under these contracts at December 31, 2012 were as follows:

Credit Ratings	Maximum Potential Collateral Requirements
	(in millions)
At BBB- and/or Baa3	$ 117
Below BBB- and/or Baa3	489

Included in these amounts are certain agreements that could require collateral in the event that one or more Southern Company system power pool participants has a credit rating change to below investment grade. Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. Additionally, any credit rating downgrade could impact the Company's ability to access capital markets, particularly the short-term debt market and the variable rate pollution control revenue bond market.

Market Price Risk

Due to cost-based rate regulation and other various cost recovery mechanisms, the Company continues to have limited exposure to market volatility in interest rates, commodity fuel prices, and prices of electricity. To manage the volatility attributable to these exposures, the Company nets the exposures, where possible, to take advantage of natural offsets and may enter into various derivative transactions for the remaining exposures pursuant to the Company's policies in areas such as counterparty exposure and risk management practices. The Company's policy is that derivatives are to be used primarily for hedging purposes and mandates strict adherence to all applicable risk management policies. Derivative positions are monitored using techniques including, but not limited to, market valuation, value at risk, stress testing, and sensitivity analysis.

To mitigate future exposure to changes in interest rates, the Company may enter into derivatives which are designated as hedges. The weighted average interest rate on $69.3 million of outstanding variable rate long-term debt that has not been hedged at January 1, 2013 was 0.13%. If the Company sustained a 100 basis point change in interest rates for all unhedged variable rate long-term debt, the change would affect annualized interest expense by approximately $693,000 at January 1, 2013. See Note 1 to the financial statements under "Financial Instruments" and Note 10 to the financial statements for additional information.

To mitigate residual risks relative to natural gas purchases, the Company continues to manage a financial hedging program for fuel purchased to operate its electric generating fleet implemented per the guidelines of the Florida PSC.

The changes in fair value of energy-related derivative contracts, substantially all of which are composed of regulatory hedges, for the years ended December 31 were as follows:

	2012 Changes	2011 Changes
	Fair Value	
	(in millions)	
Contracts outstanding at the beginning of the period, assets (liabilities), net	$ (41)	$ (11)
Contracts realized or settled	30	11
Current period changes[a]	(12)	(41)
Contracts outstanding at the end of the period, assets (liabilities), net	$ (23)	$ (41)

(a) Current period changes also include the changes in fair value of new contracts entered into during the period, if any.

The changes in the fair value positions of the energy-related derivative contracts, which are substantially all attributable to both the volume and the price of natural gas, for the years ended December 31 were as follows:

	2012 Changes	2011 Changes
	Fair Value	
	(in millions)	
Natural gas swaps	$ 17	$ (28)
Natural gas options	1	(2)
Other energy-related derivatives	—	—
Total changes	$ 18	$ (30)

The net hedge volumes of energy-related derivative contracts, for the years ended December 31 were as follows:

	2012	2011
	mmBtu* Volume	
	(in millions)	
Commodity – Natural gas swaps	71	35
Commodity – Natural gas options	—	3
Total hedge volume	71	38

*million British thermal units (mmBtu)

The weighted average swap contract cost above market prices was approximately $0.32 per mmBtu as of December 31, 2012 and $1.14 per mmBtu as of December 31, 2011. The change in option fair value is primarily attributable to the volatility of the market and the underlying change in the natural gas price. Natural gas settlements are recovered through the Company's fuel cost recovery clause.

At December 31, 2012 and 2011, substantially all of the Company's energy-related derivative contracts were designated as regulatory hedges and are related to the Company's fuel hedging program. Therefore, gains and losses are initially recorded as regulatory liabilities and assets, respectively, and then are included in fuel expense as they are recovered through the fuel cost recovery clause. Gains and losses on energy-related derivative contracts that are not designated or fail to qualify as hedges are recognized in the statements of income as incurred and were not material for any year presented.

The Company uses over-the-counter contracts that are not exchange traded but are fair valued using prices which are market observable, and thus fall into Level 2. See Note 9 to the financial statements for further discussion of fair value measurements. The maturities of the energy-related derivative contracts, which are all Level 2 of the fair value hierarchy, at December 31, 2012 were as follows:

	Fair Value Measurements December 31, 2012		
	Total	Maturity	
	Fair Value	Year 1	Years 2&3
		(in millions)	
Level 1	$ —	$ —	$ —
Level 2	(23)	(15)	(8)
Level 3	—	—	—
Fair value of contracts outstanding at end of period	$ (23)	$ (15)	$ (8)

The Company is exposed to market price risk in the event of nonperformance by counterparties to the energy-related derivative contracts. The Company only enters into agreements and material transactions with counterparties that have investment grade credit ratings by Moody's Investors Service, Inc. and Standard & Poor's Ratings Services, a division of The McGraw Hill Companies, Inc., or with counterparties who have posted collateral to cover potential credit exposure. Therefore, the Company

does not anticipate market risk exposure from nonperformance by the counterparties. For additional information, see Note 1 to the financial statements under "Financial Instruments" and Note 10 to the financial statements.

Capital Requirements and Contractual Obligations

The construction program of the Company consists of a base level capital investment and capital expenditures to comply with existing environmental statutes and regulations. These amounts include capital expenditures covered under long-term service agreements as well as capital expenditures and compliance costs associated with the MATS rule. Proposed water and coal combustion byproducts rules are not included in the construction program base level capital investment.

The Company's base level construction program investments for existing environmental statutes and regulations and the estimated incremental compliance costs related to the proposed water and coal combustion byproducts rules over the 2013 through 2015 three-year period, based on the assumption that coal combustion byproducts will continue to be regulated as non-hazardous solid waste under the proposed rule, are estimated as follows:

	2013	2014	2015
Construction program:		*(in millions)*	
Base capital	$ 177	$ 141	$ 138
Existing environmental statutes and regulations, including the MATS rule	158	319	167
Total construction program base level capital investment	**$ 335**	**$ 460**	**$ 305**
Potential incremental environmental compliance investment:			
Proposed water and coal combustion byproducts rules	$ —	$ 18	$ 70

See FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations" for additional information.

The construction program is subject to periodic review and revision, and actual construction costs may vary from these estimates because of numerous factors. These factors include: changes in business conditions; changes in load projections; storm impacts; changes in environmental statutes and regulations; the outcome of any legal challenges to the environmental rules; changes in generating plants, including unit retirements and replacements and adding or changing fuel sources at existing units, to meet regulatory requirements; changes in the expected environmental compliance program; changes in FERC rules and regulations; Florida PSC approvals; changes in legislation; the cost and efficiency of construction labor, equipment, and materials; project scope and design changes; and the cost of capital. In addition, there can be no assurance that costs related to capital expenditures will be fully recovered.

In addition, as discussed in Note 2 to the financial statements, the Company provides postretirement benefits to substantially all employees and funds trusts to the extent required by the FERC and the Florida PSC.

Other funding requirements related to obligations associated with scheduled maturities of long-term debt, as well as the related interest, derivative obligations, preference stock dividends, leases, and other purchase commitments are detailed in the contractual obligations table that follows. See Notes 1, 2, 5, 6, 7, and 10 to the financial statements for additional information.

Contractual Obligations

	2013	2014-2015	2016-2017	After 2017	Uncertain Timing[d]	Total
			(in thousands)			
Long-term debt[a] –						
Principal	$ 60,000	$ 75,000	$ 195,000	$ 923,955	$ —	$ 1,253,955
Interest	55,095	101,295	91,790	628,206	—	876,386
Financial derivative obligations[b]	16,529	10,209	374	—	—	27,112
Preference stock dividends[c]	6,203	12,405	12,405	—	—	31,013
Operating leases	18,930	18,702	2,128	—	—	39,760
Unrecognized tax benefits[d]	—	—	—	—	5,007	5,007
Purchase commitments –						
Capital[e]	313,952	764,631	—	—	—	1,078,583
Fuel[f]	347,607	459,534	216,967	160,095	—	1,184,203
Purchased power[g]	49,015	160,304	184,613	500,398	—	894,330
Other[h]	15,862	32,923	19,194	15,846	—	83,825
Pension and other postretirement benefit plans[i]	3,928	8,559	—	—	—	12,487
Total	$ 887,121	$1,643,562	$ 722,471	$2,228,500	$ 5,007	$ 5,486,661

(a) All amounts are reflected based on final maturity dates. The Company plans to continue to retire higher-cost securities and replace these obligations with lower-cost capital if market conditions permit. Variable rate interest obligations are estimated based on rates as of January 1, 2013, as reflected in the statements of capitalization. Fixed rates include, where applicable, the effects of interest rate derivatives employed to manage interest rate risk.

(b) For additional information, see Notes 1 and 10 to the financial statements.

(c) Preference stock does not mature; therefore, amounts are provided for the next five years only.

(d) The timing related to the realization of $5.0 million in unrecognized tax benefits in individual years beyond 12 months cannot be reasonably and reliably estimated due to uncertainties in the timing of the effective settlement of tax positions. See Note 5 to the financial statements under "Unrecognized Tax Benefits" for additional information.

(e) The Company provides estimated capital expenditures for a three-year period, including capital expenditures and compliance costs associated with existing environmental regulations, including the MATS rule. Such amounts exclude the Company's estimates of potential incremental environmental compliance investment to comply with proposed water and coal combustion byproducts rules, which are approximately $18 million and $70 million for years 2014 and 2015, respectively. These amounts also exclude capital expenditures covered under long-term service agreements, which are reflected separately. At December 31, 2012, significant purchase commitments were outstanding in connection with the construction program. See FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations" for additional information.

(f) Includes commitments to purchase coal and natural gas, as well as the related transportation and storage. In most cases, these contracts contain provisions for price escalation, minimum purchase levels, and other financial commitments. Natural gas purchase commitments are based on various indices at the time of delivery. Amounts reflected for natural gas purchase commitments have been estimated based on the New York Mercantile Exchange future prices at December 31, 2012.

(g) The capacity and transmission related costs associated with PPAs are recovered through the purchased power capacity clause. See Notes 3 and 7 to the financial statements for additional information.

(h) Includes long-term service agreements and contracts for the procurement of limestone. Long-term service agreements include price escalation based on inflation indices.

(i) The Company forecasts contributions to the pension and other postretirement benefit plans over a three-year period. The Company anticipates no mandatory contributions to the qualified pension plan during the next three years. Amounts presented represent estimated benefit payments for the nonqualified pension plans, estimated non-trust benefit payments for the other postretirement benefit plans, and estimated contributions to the other postretirement benefit plan trusts, all of which will be made from the Company's corporate assets. See Note 2 to the financial statements for additional information related to the pension and other postretirement benefit plans, including estimated benefit payments. Certain benefit payments will be made through the related benefit plans. Other benefit payments will be made from the Company's corporate assets.

Cautionary Statement Regarding Forward-Looking Statements

The Company's 2012 Annual Report contains forward-looking statements. Forward-looking statements include, among other things, statements concerning retail sales, retail rates, customer growth, economic recovery, fuel and environmental cost recovery and other rate actions, current and proposed environmental regulations and related estimated expenditures, access to sources of capital, projections for the qualified pension plan and postretirement benefit plan contributions, financing activities, start and completion of construction projects, filings with state and federal regulatory authorities, impact of the Tax Relief Act, impact of the ATRA, estimated sales and purchases under new power sale and purchase agreements, and estimated construction and other expenditures. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "could," "should," "expects," "plans," "anticipates," "believes," "estimates," "projects," "predicts," "potential," or "continue" or the negative of these terms or other similar terminology. There are various factors that could cause actual results to differ materially from those suggested by the forward-looking statements; accordingly, there can be no assurance that such indicated results will be realized. These factors include:

- the impact of recent and future federal and state regulatory changes, including legislative and regulatory initiatives regarding deregulation and restructuring of the electric utility industry, environmental laws including regulation of water, coal combustion byproducts, and emissions of sulfur, nitrogen, carbon, soot, particulate matter, hazardous air pollutants, including mercury, and other substances, financial reform legislation, and also changes in tax and other laws and regulations to which the Company is subject, as well as changes in application of existing laws and regulations;
- current and future litigation, regulatory investigations, proceedings, or inquiries, including the pending EPA civil action against the Company and Internal Revenue Service and state tax audits;
- the effects, extent, and timing of the entry of additional competition in the markets in which the Company operates;
- variations in demand for electricity, including those relating to weather, the general economy and recovery from the recent recession, population and business growth (and declines), the effects of energy conservation measures, and any potential economic impacts resulting from federal fiscal decisions;
- available sources and costs of fuels;
- effects of inflation;
- ability to control costs and avoid cost overruns during the development and construction of facilities;
- investment performance of the Company's employee benefit plans;
- advances in technology;
- state and federal rate regulations and the impact of pending and future rate cases and negotiations, including rate actions relating to fuel and other cost recovery mechanisms;
- internal restructuring or other restructuring options that may be pursued;
- potential business strategies, including acquisitions or dispositions of assets or businesses, which cannot be assured to be completed or beneficial to the Company;
- the ability of counterparties of the Company to make payments as and when due and to perform as required;
- the ability to obtain new short- and long-term contracts with wholesale customers;
- the direct or indirect effect on the Company's business resulting from terrorist incidents and the threat of terrorist incidents, including cyber intrusion;
- interest rate fluctuations and financial market conditions and the results of financing efforts, including the Company's credit ratings;
- the impacts of any potential U.S. credit rating downgrade or other sovereign financial issues, including impacts on interest rates, access to capital markets, impacts on currency exchange rates, counterparty performance, and the economy in general;
- the ability of the Company to obtain additional generating capacity at competitive prices;
- catastrophic events such as fires, earthquakes, explosions, floods, hurricanes, droughts, pandemic health events such as influenzas, or other similar occurrences;
- the direct or indirect effects on the Company's business resulting from incidents affecting the U.S. electric grid or operation of generating resources;
- the effect of accounting pronouncements issued periodically by standard setting bodies; and

- other factors discussed elsewhere herein and in other reports (including the Form 10-K) filed by the Company from time to time with the SEC.

The Company expressly disclaims any obligation to update any forward-looking statements.

STATEMENTS OF INCOME
For the Years Ended December 31, 2012, 2011, and 2010
Gulf Power Company 2012 Annual Report

	2012	2011	2010
		(in thousands)	
Operating Revenues:			
Retail revenues	**$ 1,144,471**	$ 1,208,490	$ 1,308,726
Wholesale revenues, non-affiliates	**106,881**	133,555	109,172
Wholesale revenues, affiliates	**123,636**	111,346	110,051
Other revenues	**64,774**	66,421	62,260
Total operating revenues	**1,439,762**	1,519,812	1,590,209
Operating Expenses:			
Fuel	**544,936**	662,283	742,322
Purchased power, non-affiliates	**51,421**	48,882	41,278
Purchased power, affiliates	**22,665**	41,612	55,948
Other operations and maintenance	**314,195**	311,358	280,585
Depreciation and amortization	**141,038**	129,651	121,498
Taxes other than income taxes	**97,313**	101,302	101,778
Total operating expenses	**1,171,568**	1,295,088	1,343,409
Operating Income	**268,194**	224,724	246,800
Other Income and (Expense):			
Allowance for equity funds used during construction	**5,221**	9,914	7,213
Interest income	**1,408**	54	123
Interest expense, net of amounts capitalized	**(60,250)**	(58,150)	(51,897)
Other income (expense), net	**(3,227)**	(4,066)	(3,011)
Total other income and (expense)	**(56,848)**	(52,248)	(47,572)
Earnings Before Income Taxes	**211,346**	172,476	199,228
Income taxes	**79,211**	61,268	71,514
Net Income	**132,135**	111,208	127,714
Dividends on Preference Stock	**6,203**	6,203	6,203
Net Income After Dividends on Preference Stock	**$ 125,932**	$ 105,005	$ 121,511

The accompanying notes are an integral part of these financial statements.

STATEMENTS OF COMPREHENSIVE INCOME
For the Years Ended December 31, 2012, 2011, and 2010
Gulf Power Company 2012 Annual Report

	2012	2011	2010
		(in thousands)	
Net Income	**$ 132,135**	$ 111,208	$ 127,714
Other comprehensive income (loss):			
Qualifying hedges:			
Changes in fair value, net of tax of $-, $-, and $(542), respectively	—	—	(863)
Reclassification adjustment for amounts included in net income, net of tax of $360, $360, and $376, respectively	**573**	573	598
Total other comprehensive income (loss)	**573**	573	(265)
Comprehensive Income	**$ 132,708**	$ 111,781	$ 127,449

The accompanying notes are an integral part of these financial statements.

STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2012, 2011, and 2010
Gulf Power Company 2012 Annual Report

	2012	2011	2010
		(in thousands)	
Operating Activities:			
Net income	$ 132,135	$ 111,208	$ 127,714
Adjustments to reconcile net income to net cash provided from operating activities —			
Depreciation and amortization, total	147,723	135,790	127,897
Deferred income taxes	174,305	63,228	82,681
Allowance for equity funds used during construction	(5,221)	(9,914)	(7,213)
Pension, postretirement, and other employee benefits	(8,109)	(356)	(23,964)
Stock based compensation expense	1,647	1,318	1,101
Hedge settlements	—	—	1,530
Other, net	4,518	(8,258)	(4,126)
Changes in certain current assets and liabilities —			
-Receivables	8,713	21,518	(36,687)
-Prepayments	417	10,150	(10,796)
-Fossil fuel stock	(6,144)	17,519	15,766
-Materials and supplies	(3,035)	(5,073)	(6,251)
-Prepaid income taxes	355	26,901	(29,630)
-Other current assets	—	40	55
-Accounts payable	(5,195)	(2,528)	15,683
-Accrued taxes	(4,705)	1,475	1,427
-Accrued compensation	481	25	5,122
-Over recovered regulatory clause revenues	(10,858)	10,247	3,192
-Other current liabilities	(7,837)	2,937	4,279
Net cash provided from operating activities	419,190	376,227	267,780
Investing Activities:			
Property additions	(313,257)	(324,372)	(285,793)
Distribution of restricted cash from pollution control revenue bonds	—	—	6,347
Cost of removal net of salvage	(28,993)	(14,471)	(1,145)
Construction payables	1,161	2,902	(21,581)
Payments pursuant to long-term service agreements	(8,119)	(8,007)	(6,011)
Other investing activities	656	420	(262)
Net cash used for investing activities	(348,552)	(343,528)	(308,445)
Financing Activities:			
Increase (decrease) in notes payable, net	16,075	21,324	4,451
Proceeds —			
Common stock issued to parent	40,000	50,000	50,000
Capital contributions from parent company	2,106	2,101	2,242
Pollution control revenue bonds	13,000	—	21,000
Senior notes	100,000	125,000	300,000
Redemptions —			
Pollution control revenue bonds	(13,000)	—	—
Senior notes	(91,363)	(608)	(215,515)
Other long-term debt	—	(110,000)	—
Payment of preference stock dividends	(6,203)	(6,203)	(6,203)
Payment of common stock dividends	(115,800)	(110,000)	(104,300)
Other financing activities	(614)	(3,419)	(3,253)
Net cash provided from (used for) financing activities	(55,799)	(31,805)	48,422
Net Change in Cash and Cash Equivalents	14,839	894	7,757
Cash and Cash Equivalents at Beginning of Year	17,328	16,434	8,677
Cash and Cash Equivalents at End of Year	$ 32,167	$ 17,328	$ 16,434
Supplemental Cash Flow Information:			
Cash paid during the period for —			
Interest (net of $2,500, $3,951 and $2,875 capitalized, respectively)	$ 58,255	$ 55,486	$ 42,521
Income taxes (net of refunds)	(96,639)	(26,345)	17,224
Noncash transactions — accrued property additions at year-end	27,369	19,439	14,475

The accompanying notes are an integral part of these financial statements.

BALANCE SHEETS
At December 31, 2012 and 2011
Gulf Power Company 2012 Annual Report

Assets	2012	2011
	(in thousands)	
Current Assets:		
Cash and cash equivalents	**$ 32,167**	$ 17,328
Receivables —		
Customer accounts receivable	**58,449**	72,754
Unbilled revenues	**53,363**	49,921
Under recovered regulatory clause revenues	**6,138**	5,530
Other accounts and notes receivable	**11,859**	13,350
Affiliated companies	**13,624**	14,844
Accumulated provision for uncollectible accounts	**(1,490)**	(1,962)
Fossil fuel stock, at average cost	**153,710**	147,567
Materials and supplies, at average cost	**53,365**	49,781
Other regulatory assets, current	**30,576**	35,849
Prepaid expenses	**62,877**	28,327
Other current assets	**2,690**	2,051
Total current assets	**477,328**	435,340
Property, Plant, and Equipment:		
In service	**4,260,844**	3,846,446
Less accumulated provision for depreciation	**1,168,055**	1,124,291
Plant in service, net of depreciation	**3,092,789**	2,722,155
Construction work in progress	**136,062**	287,173
Total property, plant, and equipment	**3,228,851**	3,009,328
Other Property and Investments	**15,737**	16,394
Deferred Charges and Other Assets:		
Deferred charges related to income taxes	**50,139**	48,210
Other regulatory assets, deferred	**372,294**	323,116
Other deferred charges and assets	**33,053**	39,493
Total deferred charges and other assets	**455,486**	410,819
Total Assets	**$ 4,177,402**	$ 3,871,881

The accompanying notes are an integral part of these financial statements.

BALANCE SHEETS
At December 31, 2012 and 2011
Gulf Power Company 2012 Annual Report

Liabilities and Stockholder's Equity	2012	2011
	(in thousands)	
Current Liabilities:		
Securities due within one year	**$ 60,000**	$ —
Notes payable	**127,002**	114,507
Accounts payable —		
Affiliated	**66,161**	54,874
Other	**54,551**	63,265
Customer deposits	**34,749**	35,779
Accrued taxes —		
Accrued income taxes	**45**	1,362
Other accrued taxes	**7,036**	12,114
Accrued interest	**12,364**	14,018
Accrued compensation	**14,966**	14,485
Other regulatory liabilities, current	**25,887**	35,639
Liabilities from risk management activities	**16,529**	22,786
Other current liabilities	**19,930**	22,916
Total current liabilities	**439,220**	391,745
Long-Term Debt (See accompanying statements)	**1,185,870**	1,235,447
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	**648,952**	458,978
Accumulated deferred investment tax credits	**5,408**	6,760
Employee benefit obligations	**126,871**	109,740
Other cost of removal obligations	**213,413**	214,598
Other regulatory liabilities, deferred	**47,863**	44,843
Other deferred credits and liabilities	**231,065**	186,824
Total deferred credits and other liabilities	**1,273,572**	1,021,743
Total Liabilities	**2,898,662**	2,648,935
Preference Stock (See accompanying statements)	**97,998**	97,998
Common Stockholder's Equity (See accompanying statements)	**1,180,742**	1,124,948
Total Liabilities and Stockholder's Equity	**$ 4,177,402**	$ 3,871,881
Commitments and Contingent Matters (See notes)		

The accompanying notes are an integral part of these financial statements.

STATEMENTS OF CAPITALIZATION
At December 31, 2012 and 2011
Gulf Power Company 2012 Annual Report

	2012	2011	2012	2011
	(in thousands)		*(percent of total)*	
Long Term Debt:				
Long-term notes payable —				
4.35% due 2013	**$ 60,000**	$ 60,000		
4.90% due 2014	**75,000**	75,000		
5.30% due 2016	**110,000**	110,000		
5.90% due 2017	**85,000**	85,000		
3.10% to 5.75% due 2020-2051	**615,000**	606,363		
Total long-term notes payable	**945,000**	936,363		
Other long-term debt —				
Pollution control revenue bonds —				
0.55% to 6.00% due 2022-2049	**239,625**	239,625		
Variable rates (0.13% to 0.17% at 1/1/13) due 2022-2039	**69,330**	69,330		
Total other long-term debt	**308,955**	308,955		
Unamortized debt discount	**(8,085)**	(9,871)		
Total long-term debt (annual interest requirement — $55.1 million)	**1,245,870**	1,235,447		
Less amount due within one year	**60,000**	—		
Long-term debt excluding amount due within one year	**1,185,870**	1,235,447	**48.1%**	50.2%
Preferred and Preference Stock:				
Authorized - 20,000,000 shares—preferred stock				
- 10,000,000 shares—preference stock				
Outstanding - $100 par or stated value — 6% preference stock	**53,886**	53,886		
— 6.45% preference stock	**44,112**	44,112		
- 1,000,000 shares (non-cumulative)				
Total preference stock (annual dividend requirement — $6.2 million)	**97,998**	97,998	**4.0**	4.0
Common Stockholder's Equity:				
Common stock, without par value —				
Authorized - 20,000,000 shares				
Outstanding - 2012: 4,542,717 shares				
- 2011: 4,142,717 shares	**393,060**	353,060		
Paid-in capital	**547,798**	542,709		
Retained earnings	**241,465**	231,333		
Accumulated other comprehensive income (loss)	**(1,581)**	(2,154)		
Total common stockholder's equity	**1,180,742**	1,124,948	**47.9**	45.8
Total Capitalization	**$ 2,464,610**	$ 2,458,393	**100.0%**	100.0%

The accompanying notes are an integral part of these financial statements.

STATEMENTS OF COMMON STOCKHOLDER'S EQUITY
For the Years Ended December 31, 2012, 2011, and 2010
Gulf Power Company 2012 Annual Report

	Number of Common Shares Issued	Common Stock	Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
			(in thousands)			
Balance at December 31, 2009	3,143	$ 253,060	$ 534,577	$ 219,117	$ (2,462)	$ 1,004,292
Net income after dividends on preference stock	—	—	—	121,511	—	121,511
Issuance of common stock	500	50,000	—	—	—	50,000
Capital contributions from parent company	—	—	3,798	—	—	3,798
Other comprehensive income (loss)	—	—	—	—	(265)	(265)
Cash dividends on common stock	—	—	—	(104,300)	—	(104,300)
Balance at December 31, 2010	3,643	303,060	538,375	236,328	(2,727)	1,075,036
Net income after dividends on preference stock	—	—	—	105,005	—	105,005
Issuance of common stock	500	50,000	—	—	—	50,000
Capital contributions from parent company	—	—	4,334	—	—	4,334
Other comprehensive income (loss)	—	—	—	—	573	573
Cash dividends on common stock	—	—	—	(110,000)	—	(110,000)
Balance at December 31, 2011	**4,143**	**353,060**	**542,709**	**231,333**	**(2,154)**	**1,124,948**
Net income after dividends on preference stock	—	—	—	**125,932**	—	**125,932**
Issuance of common stock	**400**	**40,000**	—	—	—	**40,000**
Capital contributions from parent company	—	—	**5,089**	—	—	**5,089**
Other comprehensive income (loss)	—	—	—	—	**573**	**573**
Cash dividends on common stock	—	—	—	**(115,800)**	—	**(115,800)**
Balance at December 31, 2012	**4,543**	**$ 393,060**	**$ 547,798**	**$ 241,465**	**$ (1,581)**	**$ 1,180,742**

The accompanying notes are an integral part of these financial statements.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

General

Gulf Power Company (the Company) is a wholly owned subsidiary of The Southern Company (Southern Company), which is the parent company of four traditional operating companies, as well as Southern Power Company (Southern Power), Southern Company Services, Inc. (SCS), Southern Communications Services, Inc. (SouthernLINC Wireless), Southern Company Holdings, Inc. (Southern Holdings), Southern Nuclear Operating Company, Inc. (Southern Nuclear), and other direct and indirect subsidiaries. The traditional operating companies — the Company, Alabama Power Company (Alabama Power), Georgia Power Company (Georgia Power), and Mississippi Power Company (Mississippi Power) — are vertically integrated utilities providing electric service in four Southeastern states. The Company operates as a vertically integrated utility providing electricity to retail customers in northwest Florida and to wholesale customers in the Southeast. Southern Power constructs, acquires, owns, and manages generation assets, including renewable energy projects, and sells electricity at market-based rates in the wholesale market. SCS, the system service company, provides, at cost, specialized services to Southern Company and its subsidiary companies. SouthernLINC Wireless provides digital wireless communications for use by Southern Company and its subsidiary companies and also markets these services to the public and provides fiber cable services within the Southeast. Southern Holdings is an intermediate holding company subsidiary, primarily for Southern Company's investments in leveraged leases. Southern Nuclear operates and provides services to the Southern Company system's nuclear power plants.

The equity method is used for entities in which the Company has significant influence but does not control.

The Company is subject to regulation by the Federal Energy Regulatory Commission (FERC) and the Florida Public Service Commission (PSC). The Company follows generally accepted accounting principles (GAAP) in the U.S. and complies with the accounting policies and practices prescribed by its regulatory commissions. The preparation of financial statements in conformity with GAAP requires the use of estimates, and the actual results may differ from those estimates. Certain prior years' data presented in the financial statements have been reclassified to conform to the current year presentation.

Affiliate Transactions

The Company has an agreement with SCS under which the following services are rendered to the Company at direct or allocated cost: general and design engineering, operations, purchasing, accounting, finance and treasury, tax, information technology, marketing, auditing, insurance and pension administration, human resources, systems and procedures, digital wireless communications, and other services with respect to business and operations and power pool transactions. Costs for these services amounted to $95.9 million, $97.4 million, and $98.8 million during 2012, 2011, and 2010, respectively. Cost allocation methodologies used by SCS prior to the repeal of the Public Utility Holding Company Act of 1935, as amended, were approved by the Securities and Exchange Commission (SEC). Subsequently, additional cost allocation methodologies have been reported to the FERC and management believes they are reasonable. The FERC permits services to be rendered at cost by system service companies.

The Company has agreements with Georgia Power and Mississippi Power under which the Company owns a portion of Plant Scherer and Plant Daniel, respectively. Georgia Power operates Plant Scherer and Mississippi Power operates Plant Daniel. The Company reimbursed Georgia Power $6.9 million, $6.7 million, and $8.9 million and Mississippi Power $21.1 million, $23.4 million, and $25.0 million in 2012, 2011, and 2010, respectively, for its proportionate share of related expenses. See Note 4 and Note 7 under "Operating Leases" for additional information.

The Company entered into a power purchase agreement (PPA) with Southern Power for a total of approximately 292 megawatts (MWs) annually from June 2009 through May 2014. Purchased power expenses associated with the PPA were $14.7 million, $14.3 million, and $14.5 million in 2012, 2011, and 2010, respectively, and fuel costs associated with the PPA were $2.6 million, $1.8 million, and $3.3 million in 2012, 2011, and 2010, respectively. These costs have been approved for recovery by the Florida PSC through the Company's fuel and purchased power capacity cost recovery clauses. Additionally, the Company had $4.2 million of deferred capacity expenses included in prepaid expenses and other regulatory liabilities, current in the balance sheets at December 31, 2012 and 2011, respectively. See Note 7 under "Fuel and Purchased Power Agreements" for additional information.

The Company has an agreement with Georgia Power under the transmission facility cost allocation tariff for delivery of power from the Company's resources in the state of Georgia. The Company reimbursed Georgia Power $2.4 million in each of the years 2012, 2011, and 2010 for its share of related expenses.

The Company has an agreement with Alabama Power under which Alabama Power will make transmission system upgrades to ensure firm delivery of energy under a non-affiliate PPA, which was entered into in 2009 for the capacity and energy from a combined cycle plant located in Autauga County, Alabama. Revenue requirement obligations to Alabama Power for these upgrades are estimated to be $136.7 million for the entire project. These costs began in July 2012 and will continue through 2023. The Company reimbursed Alabama Power $3.0 million in 2012 for the revenue requirements. These costs have been approved for recovery by the Florida PSC through the Company's purchased power capacity cost recovery clause and by the FERC in the transmission facilities cost allocation tariff.

The Company provides incidental services to and receives such services from other Southern Company subsidiaries which are generally minor in duration and amount. Except as described herein, the Company neither provided nor received any material services to or from affiliates in 2012 or 2010. In 2011, the Company provided storm restoration assistance to Alabama Power totaling $1.4 million.

The traditional operating companies, including the Company, and Southern Power may jointly enter into various types of wholesale energy, natural gas, and certain other contracts, either directly or through SCS, as agent. Each participating company may be jointly and severally liable for the obligations incurred under these agreements. See Note 7 under "Fuel and Purchased Power Agreements" for additional information.

New Accounting Pronouncements

In June 2011, the Financial Accounting Standards Board (FASB) issued guidance, ASU 2011-05, *Presentation of Comprehensive Income*, requiring companies to present the total of comprehensive income, the components of net income, and the components of other comprehensive income, in a single continuous statement of comprehensive income or in two separate but consecutive statements. In October 2012, the FASB issued additional guidance, ASU 2012-04, *Technical Corrections and Improvements* (ASU 2012-04), in which it clarified that those companies presenting consecutive statements must begin the statement of comprehensive income with net income. The Company retroactively adopted the guidance in ASU 2012-04 beginning with its financial statements for the three years ended December 31, 2012, 2011, and 2010.

Regulatory Assets and Liabilities

The Company is subject to the provisions of the FASB in accounting for the effects of rate regulation. Regulatory assets represent probable future revenues associated with certain costs that are expected to be recovered from customers through the ratemaking process. Regulatory liabilities represent probable future reductions in revenues associated with amounts that are expected to be credited to customers through the ratemaking process.

Regulatory assets and (liabilities) reflected in the balance sheets at December 31 relate to:

	2012	2011	Note
	(in thousands)		
Deferred income tax charges	**$ 46,788**	$ 44,533	(a)
Deferred income tax charges — Medicare subsidy	**3,678**	4,005	(b)
Asset retirement obligations	**(5,793)**	(5,653)	(a,j)
Other cost of removal obligations	**(213,413)**	(214,598)	(a)
Deferred income tax credits	**(6,515)**	(8,113)	(a)
Loss on reacquired debt	**16,400**	14,437	(c)
Vacation pay	**9,238**	8,973	(d,j)
Under recovered regulatory clause revenues	**3,523**	3,133	(e)
Over recovered regulatory clause revenues	**(17,092)**	(27,950)	(e)
Property damage reserve	**(31,956)**	(30,473)	(f)
Fuel hedging (realized and unrealized) losses	**29,038**	43,071	(g,j)
Fuel hedging (realized and unrealized) gains	**(4,358)**	(197)	(g,j)
PPA charges	**137,568**	94,986	(j,k)
Generation site selection/evaluation costs	**1,344**	20,415	(l)
Other regulatory assets	**9,690**	1,675	(e,j)
Environmental remediation	**60,452**	61,625	(h,j)
PPA credits	**(7,502)**	(7,536)	(j,k)
Other regulatory liabilities	**(534)**	(798)	(f)
Retiree benefit plans, net	**141,429**	116,091	(i,j)
Total regulatory assets (liabilities), net	**$ 171,985**	$ 117,626	

Note: The recovery and amortization periods for these regulatory assets and (liabilities) are as follows:

(a) Asset retirement and removal assets and liabilities are recorded, deferred income tax assets are recovered, and deferred income tax liabilities are amortized over the related property lives, which may range up to 65 years. Asset retirement and removal assets and liabilities will be settled and trued up following completion of the related activities.

(b) Recovered and amortized over periods not exceeding 14 years.

(c) Recovered over either the remaining life of the original issue or, if refinanced, over the life of the new issue, which may range up to 40 years.

(d) Recorded as earned by employees and recovered as paid, generally within one year. This includes both vacation and banked holiday pay.

(e) Recorded and recovered or amortized as approved by the Florida PSC, generally within one year.

(f) Recorded and recovered or amortized as approved by the Florida PSC.

(g) Fuel hedging assets and liabilities are recognized over the life of the underlying hedged purchase contracts, which generally do not exceed five years. Upon final settlement, costs are recovered through the fuel cost recovery clause.

(h) Recovered through the environmental cost recovery clause when the remediation is performed.

(i) Recovered and amortized over the average remaining service period which may range up to 14 years. See Note 2 for additional information.

(j) Not earning a return as offset in rate base by a corresponding asset or liability.

(k) Recovered over the life of the PPA for periods up to 14 years.

(l) Deferred pursuant to Florida Statute while the Company continues to evaluate certain potential new generation projects.

In the event that a portion of the Company's operations is no longer subject to applicable accounting rules for rate regulation, the Company would be required to write off to income or reclassify to accumulated other comprehensive income (OCI) related regulatory assets and liabilities that are not specifically recoverable through regulated rates. In addition, the Company would be required to determine if any impairment to other assets, including plant, exists and write down the assets, if impaired, to their fair values. All regulatory assets and liabilities are to be reflected in rates. See Note 3 under "Retail Regulatory Matters" for additional information.

Revenues

Wholesale capacity revenues are generally recognized on a levelized basis over the appropriate contract period. Energy and other revenues are recognized as services are provided. Unbilled revenues related to retail sales are accrued at the end of each fiscal period. Electric rates for the Company include provisions to adjust billings for fluctuations in fuel costs, the energy component of purchased power costs, and certain other costs. The Company continuously monitors the over or under recovered fuel cost balance in light of the inherent variability in fuel costs. The Company is required to notify the Florida PSC if the projected fuel cost over or under recovery is expected to exceed 10% of the projected fuel revenue applicable for the period and indicate if an adjustment to the fuel cost recovery factor is being requested. The Company has similar retail cost recovery clauses for energy conservation costs, purchased power capacity costs, and environmental compliance costs. Revenues are adjusted for differences between these actual costs and amounts billed in current regulated rates. Under or over recovered regulatory clause revenues are recorded in the balance sheets and are recovered or returned to customers through adjustments to the billing factors. Annually, the Company petitions for recovery of projected costs including any true-up amounts from prior periods, and approved rates are implemented each January. See Note 3 under "Retail Regulatory Matters" for additional information.

The Company has a diversified base of customers. No single customer or industry comprises 10% or more of revenues. For all periods presented, uncollectible accounts averaged less than 1% of revenues.

Fuel Costs

Fuel costs are expensed as the fuel is used. Fuel expense generally includes fuel transportation costs and the cost of purchased emissions allowances as they are used. Fuel expense and emissions allowance costs are recovered by the Company through the fuel cost recovery and environmental cost recovery rates, respectively, approved annually by the Florida PSC.

Income and Other Taxes

The Company uses the liability method of accounting for deferred income taxes and provides deferred income taxes for all significant income tax temporary differences. Investment tax credits utilized are deferred and amortized to income over the average life of the related property. Taxes that are collected from customers on behalf of governmental agencies to be remitted to these agencies are presented net on the statements of income.

In accordance with accounting standards related to the uncertainty in income taxes, the Company recognizes tax positions that are "more likely than not" of being sustained upon examination by the appropriate taxing authorities. See Note 5 under "Unrecognized Tax Benefits" for additional information.

Property, Plant, and Equipment

Property, plant, and equipment is stated at original cost less any regulatory disallowances and impairments. Original cost includes: materials; labor; minor items of property; appropriate administrative and general costs; payroll-related costs such as taxes, pensions, and other benefits; and the interest capitalized and cost of equity funds used during construction.

The Company's property, plant, and equipment in service consisted of the following at December 31:

	2012	2011
	(in thousands)	
Generation	$ **2,598,773**	$ 2,283,494
Transmission	**429,341**	368,542
Distribution	**1,069,065**	1,030,546
General	**161,379**	161,322
Plant acquisition adjustment	**2,286**	2,542
Total plant in service	$ **4,260,844**	$ 3,846,446

The cost of replacements of property, exclusive of minor items of property, is capitalized. The cost of maintenance, repairs, and replacement of minor items of property is charged to other operations and maintenance expense as incurred or performed.

Depreciation and Amortization

Depreciation of the original cost of utility plant in service is provided primarily by using composite straight-line rates, which approximated 3.6% in 2012, 3.5% in 2011, and 3.5% in 2010. Depreciation studies are conducted periodically to update the composite rates. These studies are approved by the Florida PSC and the FERC. When property subject to depreciation is retired or otherwise disposed of in the normal course of business, its original cost, together with the cost of removal, less salvage, is charged to accumulated depreciation. For other property dispositions, the applicable cost and accumulated depreciation are removed from the balance sheet accounts, and a gain or loss is recognized. Minor items of property included in the original cost of the plant are retired when the related property unit is retired.

Asset Retirement Obligations and Other Costs of Removal

Asset retirement obligations are computed as the present value of the ultimate costs for an asset's future retirement and are recorded in the period in which the liability is incurred. The costs are capitalized as part of the related long-lived asset and depreciated over the asset's useful life. The Company has received an order from the Florida PSC allowing the continued accrual of other future retirement costs for long-lived assets that the Company does not have a legal obligation to retire. Accordingly, the accumulated removal costs for these obligations are reflected in the balance sheets as a regulatory liability.

The liability for asset retirement obligations primarily relates to the Company's combustion turbines at its Pea Ridge facility, various landfill sites, a barge unloading dock, asbestos removal, ash ponds, and disposal of polychlorinated biphenyls in certain transformers. The Company also has identified retirement obligations related to certain transmission and distribution facilities, certain wireless communication towers, and certain structures authorized by the U.S. Army Corps of Engineers. However, liabilities for the removal of these assets have not been recorded because the range of time over which the Company may settle these obligations is unknown and cannot be reasonably estimated. The Company will continue to recognize in the statements of income allowed removal costs in accordance with its regulatory treatment. Any differences between costs recognized in accordance with accounting standards related to asset retirement and environmental obligations and those reflected in rates are recognized as either a regulatory asset or liability, as ordered by the Florida PSC, and are reflected in the balance sheets.

Details of the asset retirement obligations included in the balance sheets are as follows:

	2012	2011
	(in thousands)	
Balance at beginning of year	$ 10,729	$ 11,470
Liabilities incurred	—	106
Liabilities settled	(107)	(1,050)
Accretion	507	545
Cash flow revisions	4,926	(342)
Balance at end of year	$ 16,055	$ 10,729

Allowance for Funds Used During Construction

In accordance with regulatory treatment, the Company records allowance for funds used during construction (AFUDC), which represents the estimated debt and equity costs of capital funds that are necessary to finance the construction of new regulated facilities. While cash is not realized currently from such allowance, AFUDC increases the revenue requirement over the service life of the plant through a higher rate base and higher depreciation. The equity component of AFUDC is not included in calculating taxable income. The average annual AFUDC rate was 6.72% for the year 2012. The average annual AFUDC rate was 7.65% for both 2011 and 2010. AFUDC, net of income taxes, as a percentage of net income after dividends on preference stock was 5.36%, 11.75%, and 7.39% for 2012, 2011, and 2010, respectively.

Impairment of Long-Lived Assets and Intangibles

The Company evaluates long-lived assets for impairment when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. The determination of whether an impairment has occurred is based on either a specific regulatory disallowance or an estimate of undiscounted future cash flows attributable to the assets, as compared with the carrying value of the assets. If an impairment has occurred, the amount of the impairment recognized is determined by either the amount of regulatory disallowance or by estimating the fair value of the assets and recording a loss if the carrying value is greater

than the fair value. For assets identified as held for sale, the carrying value is compared to the estimated fair value less the cost to sell in order to determine if an impairment loss is required. Until the assets are disposed of, their estimated fair value is re-evaluated when circumstances or events change.

Property Damage Reserve

The Company accrues for the cost of repairing damages from major storms and other uninsured property damages, including uninsured damages to transmission and distribution facilities, generation facilities, and other property. The costs of such damage are charged to the reserve. The Florida PSC approved annual accrual to the property damage reserve is $3.5 million, with a target level for the reserve between $48.0 million and $55.0 million. The Florida PSC also authorized the Company to make additional accruals above the $3.5 million at the Company's discretion. The Company accrued total expenses of $3.5 million in each of 2012, 2011, and 2010. As of December 31, 2012 and 2011, the balance in the Company's property damage reserve totaled approximately $32.0 million and $30.5 million, respectively, which is included in deferred liabilities in the balance sheets.

When the property damage reserve is inadequate to cover the cost of major storms, the Florida PSC can authorize a storm cost recovery surcharge to be applied to customer bills. Such a surcharge was authorized in 2005 after Hurricane Ivan in 2004 and was extended by a 2006 Florida PSC order approving a stipulation to address costs incurred as a result of Hurricanes Dennis and Katrina in 2005. Under the 2006 Florida PSC order, if the Company incurs cumulative costs for storm recovery activities in excess of $10 million during any calendar year, the Company would be permitted to file a streamlined formal request for an interim surcharge. Any interim surcharge would provide for the recovery, subject to refund, of up to 80% of the claimed costs for storm recovery activities. The Company would then petition the Florida PSC for full recovery through a final or non-interim surcharge or other cost recovery mechanism. After the effective date of new base rates, the Company will retain the right to request relief on an expedited basis from the Florida PSC without the thresholds set forth in the stipulation.

Injuries and Damages Reserve

The Company is subject to claims and lawsuits arising in the ordinary course of business. As permitted by the Florida PSC, the Company accrues for the uninsured costs of injuries and damages by charges to income amounting to $1.6 million annually. The Florida PSC has also given the Company the flexibility to increase its annual accrual above $1.6 million to the extent the balance in the reserve does not exceed $2 million and to defer expense recognition of liabilities greater than the balance in the reserve. The cost of settling claims is charged to the reserve. The injuries and damages reserve was $3.1 million and $2.7 million at December 31, 2012 and 2011, respectively. For 2012, $1.6 million and $1.5 million are included in current liabilities and deferred credits and other liabilities in the balance sheets, respectively. For 2011, $1.6 million and $1.1 million are included in current liabilities and deferred credits and other liabilities in the balance sheets, respectively. There were no liabilities in excess of the reserve balance at December 31, 2012 and 2011.

Cash and Cash Equivalents

For purposes of the financial statements, temporary cash investments are considered cash equivalents. Temporary cash investments are securities with original maturities of 90 days or less.

Materials and Supplies

Generally, materials and supplies include the average cost of transmission, distribution, and generating plant materials. Materials are charged to inventory when purchased and then expensed or capitalized to plant, as appropriate, at weighted average cost when installed.

Fuel Inventory

Fuel inventory includes the average cost of oil, natural gas, coal, transportation, and emissions allowances. Fuel is charged to inventory when purchased and then expensed, at weighted average cost, as used. Fuel expense and emissions allowance costs are recovered by the Company through the fuel cost recovery and environmental cost recovery rates, respectively, approved annually by the Florida PSC. Emissions allowances granted by the Environmental Protection Agency (EPA) are included in inventory at zero cost.

Financial Instruments

The Company uses derivative financial instruments to limit exposure to fluctuations in interest rates, the prices of certain fuel purchases, and electricity purchases and sales. All derivative financial instruments are recognized as either assets or liabilities (included in "Other" or shown separately as "Risk Management Activities") and are measured at fair value. See Note 9 for additional information. Substantially all of the Company's bulk energy purchases and sales contracts that meet the definition of a

derivative are excluded from fair value accounting requirements because they qualify for the "normal" scope exception, and are accounted for under the accrual method. Other derivative contracts qualify as cash flow hedges of anticipated transactions or are recoverable through the Florida PSC approved fuel hedging program. This results in the deferral of related gains and losses in OCI or regulatory assets and liabilities, respectively, until the hedged transactions occur. Any ineffectiveness arising from cash flow hedges is recognized currently in net income. Other derivative contracts are marked to market through current period income and are recorded on a net basis in the statements of income. See Note 10 for additional information.

The Company does not offset fair value amounts recognized for multiple derivative instruments executed with the same counterparty under a master netting arrangement. Additionally, the Company had no outstanding collateral repayment obligations or rights to reclaim collateral arising from derivative instruments recognized at December 31, 2012.

The Company is exposed to losses related to financial instruments in the event of counterparties' nonperformance. The Company has established controls to determine and monitor the creditworthiness of counterparties in order to mitigate the Company's exposure to counterparty credit risk.

Comprehensive Income

The objective of comprehensive income is to report a measure of all changes in common stock equity of an enterprise that result from transactions and other economic events of the period other than transactions with owners. Comprehensive income consists of net income, changes in the fair value of qualifying cash flow hedges, and reclassifications for amounts included in net income.

2. RETIREMENT BENEFITS

The Company has a defined benefit, trusteed, pension plan covering substantially all employees. This qualified pension plan is funded in accordance with requirements of the Employee Retirement Income Security Act of 1974, as amended (ERISA). In December 2012, the Company contributed $13.4 million to the qualified pension plan. No mandatory contributions to the qualified pension plan are anticipated for the year ending December 31, 2013. The Company also provides certain defined benefit pension plans for a selected group of management and highly compensated employees. Benefits under these non-qualified pension plans are funded on a cash basis. In addition, the Company provides certain medical care and life insurance benefits for retired employees through other postretirement benefit plans. The Company funds its other postretirement trusts to the extent required by the FERC. For the year ending December 31, 2013, no other postretirement trust contributions are expected.

Actuarial Assumptions

The weighted average rates assumed in the actuarial calculations used to determine both the benefit obligations as of the measurement date and the net periodic costs for the pension and other postretirement benefit plans for the following year are presented below. Net periodic benefit costs were calculated in 2009 for the 2010 plan year using discount rates for the pension plans and the other postretirement benefit plans of 5.93% and 5.84%, respectively, and an annual salary increase of 4.18%.

	2012	2011	2010
Discount rate:			
Pension plans	**4.27%**	4.98%	5.53%
Other postretirement benefit plans	**4.06**	4.88	5.41
Annual salary increase	**3.59**	3.84	3.84
Long-term return on plan assets:			
Pension plans	**8.20**	8.45	8.45
Other postretirement benefit plans	**8.02**	8.11	8.18

The Company estimates the expected rate of return on pension plan and other postretirement benefit plan assets using a financial model to project the expected return on each current investment portfolio. The analysis projects an expected rate of return on each of seven different asset classes in order to arrive at the expected return on the entire portfolio relying on each trust's target asset allocation and reasonable capital market assumptions. The financial model is based on four key inputs: anticipated returns by asset class (based in part on historical returns), each trust's target asset allocation, an anticipated inflation rate, and the projected impact of a periodic rebalancing of each trust's portfolio.

An additional assumption used in measuring the accumulated other postretirement benefit obligations (APBO) is the weighted average medical care cost trend rate. The weighted average medical care cost trend rates used in measuring the APBO as of December 31, 2012 were as follows:

	Initial Cost Trend Rate	Ultimate Cost Trend Rate	Year That Ultimate Rate Is Reached
Pre-65	8.00%	5.00%	2020
Post-65 medical	6.00	5.00	2020
Post-65 prescription	6.00	5.00	2020

An annual increase or decrease in the assumed medical care cost trend rate of 1% would affect the APBO and the service and interest cost components at December 31, 2012 as follows:

	1 Percent Increase	1 Percent Decrease
	(in thousands)	
Benefit obligation	$ 3,399	$ (2,897)
Service and interest costs	198	(169)

Pension Plans

The total accumulated benefit obligation for the pension plans was $371 million at December 31, 2012 and $321 million at December 31, 2011. Changes in the projected benefit obligations and the fair value of plan assets during the plan years ended December 31, 2012 and 2011were as follows:

	2012	2011
	(in thousands)	
Change in benefit obligation		
Benefit obligation at beginning of year	**$ 352,834**	$ 316,286
Service cost	**9,101**	8,431
Interest cost	**17,199**	17,074
Benefits paid	**(14,046)**	(13,807)
Plan amendments	**426**	—
Actuarial loss	**47,987**	24,850
Balance at end of year	**413,501**	352,834
Change in plan assets		
Fair value of plan assets at beginning of year	**304,324**	307,828
Actual return on plan assets	**45,762**	9,552
Employer contributions	**14,220**	751
Benefits paid	**(14,046)**	(13,807)
Fair value of plan assets at end of year	**350,260**	304,324
Accrued liability	**$ (63,241)**	$ (48,510)

At December 31, 2012, the projected benefit obligations for the qualified and non-qualified pension plans were $393 million and $20 million, respectively. All pension plan assets are related to the qualified pension plan.

Amounts recognized in the balance sheets at December 31, 2012 and 2011 related to the Company's pension plans consist of the following:

	2012	2011
	(in thousands)	
Other regulatory assets	**$ 139,261**	$ 115,853
Current liabilities, other	**(855)**	(794)
Employee benefit obligations	**(62,386)**	(47,716)

Presented below are the amounts included in regulatory assets at December 31, 2012 and 2011 related to the defined benefit pension plans that had not yet been recognized in net periodic pension cost along with the estimated amortization of such amounts for 2013.

	2012	2011	Estimated Amortization in 2013
		(in thousands)	
Prior service cost	**$ 5,565**	$ 6,402	**$ 1,164**
Net (gain) loss	**133,696**	109,451	**8,385**
Other regulatory assets	**$ 139,261**	$ 115,853	

The changes in the balance of regulatory assets related to the defined benefit pension plans for the years ended December 31, 2012 and 2011 are presented in the following table:

	Regulatory Assets
	(in thousands)
Balance at December 31, 2010	$ 75,096
Net (gain) loss	42,531
Change in prior service costs	—
Reclassification adjustments:	
Amortization of prior service costs	(1,262)
Amortization of net gain (loss)	(512)
Total reclassification adjustments	(1,774)
Total change	40,757
Balance at December 31, 2011	$ 115,853
Net (gain) loss	**28,157**
Change in prior service costs	**426**
Reclassification adjustments:	
Amortization of prior service costs	**(1,262)**
Amortization of net gain (loss)	**(3,913)**
Total reclassification adjustments	**(5,175)**
Total change	**23,408**
Balance at December 31, 2012	**$ 139,261**

Components of net periodic pension cost were as follows:

	2012	2011	2010
		(in thousands)	
Service cost	**$ 9,101**	$ 8,431	$ 7,853
Interest cost	**17,199**	17,074	17,305
Expected return on plan assets	**(25,932)**	(27,232)	(24,695)
Recognized net (gain) loss	**3,913**	512	398
Net amortization	**1,262**	1,262	1,302
Net periodic pension cost	**$ 5,543**	$ 47	$ 2,163

Net periodic pension cost is the sum of service cost, interest cost, and other costs netted against the expected return on plan assets. The expected return on plan assets is determined by multiplying the expected rate of return on plan assets and the market-related value of plan assets. In determining the market-related value of plan assets, the Company has elected to amortize changes in the market value of all plan assets over five years rather than recognize the changes immediately. As a result, the accounting value of plan assets that is used to calculate the expected return on plan assets differs from the current fair value of the plan assets.

Future benefit payments reflect expected future service and are estimated based on assumptions used to measure the projected benefit obligation for the pension plans. At December 31, 2012, estimated benefit payments were as follows:

	Benefit Payments
	(in thousands)
2013	$ 15,767
2014	16,606
2015	17,427
2016	18,272
2017	19,383
2018 to 2022	113,108

Other Postretirement Benefits

Changes in the APBO and in the fair value of plan assets during the plan years ended December 31, 2012 and 2011 were as follows:

	2012	2011
	(in thousands)	
Change in benefit obligation		
Benefit obligation at beginning of year	**$ 70,923**	$ 69,617
Service cost	**1,167**	1,132
Interest cost	**3,367**	3,658
Benefits paid	**(3,854)**	(4,189)
Actuarial loss	**3,468**	292
Plan amendments	**—**	—
Retiree drug subsidy	**324**	413
Balance at end of year	**75,395**	70,923
Change in plan assets		
Fair value of plan assets at beginning of year	**14,978**	15,697
Actual return on plan assets	**2,131**	514
Employer contributions	**2,648**	2,543
Benefits paid	**(3,530)**	(3,776)
Fair value of plan assets at end of year	**16,227**	14,978
Accrued liability	**$ (59,168)**	$ (55,945)

Amounts recognized in the balance sheets at December 31, 2012 and 2011 related to the Company's other postretirement benefit plans consist of the following:

	2012	2011
	(in thousands)	
Regulatory assets	**$ 2,169**	$ 239
Current liabilities, other	**(661)**	(624)
Employee benefit obligations	**(58,507)**	(55,321)

Presented below are the amounts included in regulatory assets at December 31, 2012 and 2011 related to the other postretirement benefit plans that had not yet been recognized in net periodic other postretirement benefit cost along with the estimated amortization of such amounts for 2013.

	2012	2011	Estimated Amortization in 2013
		(in thousands)	
Prior service cost	**$ 324**	$ 510	**$ 186**
Net (gain) loss	**1,845**	(464)	**—**
Transition obligation	**—**	193	**—**
Regulatory assets (liabilities)	**$ 2,169**	$ 239	

The changes in the balance of regulatory assets and regulatory liabilities related to the other postretirement benefit plans for the plan years ended December 31, 2012 and 2011 are presented in the following table:

	Regulatory Assets	Regulatory Liabilities
	(in thousands)	
Balance at December 31, 2010	$ —	$ (166)
Net (gain) loss	635	166
Change in prior service costs/transition obligation	—	—
Reclassification adjustments:		
Amortization of transition obligation	(257)	—
Amortization of prior service costs	(186)	—
Amortization of net gain (loss)	47	—
Total reclassification adjustments	(396)	—
Total change	239	166
Balance at December 31, 2011	$ 239	$ —
Net (gain) loss	**2,309**	—
Change in prior service costs/transition obligation	—	—
Reclassification adjustments:		
Amortization of transition obligation	**(193)**	—
Amortization of prior service costs	**(186)**	—
Amortization of net gain (loss)	—	—
Total reclassification adjustments	**(379)**	—
Total change	**1,930**	—
Balance at December 31, 2012	**$ 2,169**	**$ —**

Components of the other postretirement benefit plans' net periodic cost were as follows:

	2012	2011	2010
		(in thousands)	
Service cost	**$ 1,167**	$ 1,132	$ 1,304
Interest cost	**3,367**	3,658	4,121
Expected return on plan assets	**(1,311)**	(1,445)	(1,481)
Net amortization	**379**	396	406
Net postretirement cost	**$ 3,602**	$ 3,741	$ 4,350

Future benefit payments, including prescription drug benefits, reflect expected future service and are estimated based on assumptions used to measure the APBO for the other postretirement benefit plans. Estimated benefit payments are reduced by drug subsidy receipts expected as a result of the Medicare Prescription Drug, Improvement, and Modernization Act of 2003 as follows:

	Benefit Payments	Subsidy Receipts	Total
		(in thousands)	
2013	$ 4,473	$ (488)	$ 3,985
2014	4,707	(537)	4,170
2015	4,903	(589)	4,314
2016	5,117	(643)	4,474
2017	5,211	(705)	4,506
2018 to 2022	26,913	(3,804)	23,109

Benefit Plan Assets

Pension plan and other postretirement benefit plan assets are managed and invested in accordance with all applicable requirements, including ERISA and the Internal Revenue Code of 1986, as amended (Internal Revenue Code). The Company's investment policies for both the pension plan and the other postretirement benefit plans cover a diversified mix of assets, including equity and fixed income securities, real estate, and private equity. Derivative instruments are used primarily to gain efficient exposure to the various asset classes and as hedging tools. The Company minimizes the risk of large losses primarily through diversification but also monitors and manages other aspects of risk.

The composition of the Company's pension plan and other postretirement benefit plan assets as of December 31, 2012 and 2011, along with the targeted mix of assets for each plan, is presented below:

	Target	2012	2011
Pension plan assets:			
Domestic equity	26%	**28%**	29%
International equity	25	**24**	25
Fixed income	23	**27**	23
Special situations	3	**1**	—
Real estate investments	14	**13**	14
Private equity	9	**7**	9
Total	100%	**100%**	100%
Other postretirement benefit plan assets:			
Domestic equity	25%	**27%**	28%
International equity	24	**23**	24
Domestic fixed income	25	**29**	26
Special situations	3	**1**	—
Real estate investments	14	**13**	13
Private equity	9	**7**	9
Total	100%	**100%**	100%

The investment strategy for plan assets related to the Company's qualified pension plan is to be broadly diversified across major asset classes. The asset allocation is established after consideration of various factors that affect the assets and liabilities of the pension plan including, but not limited to, historical and expected returns, volatility, correlations of asset classes, the current level of assets and liabilities, and the assumed growth in assets and liabilities. Because a significant portion of the liability of the pension plan is long-term in nature, the assets are invested consistent with long-term investment expectations for return and risk. To manage the actual asset class exposures relative to the target asset allocation, the Company employs a formal rebalancing program. As additional risk management, external investment managers and service providers are subject to written guidelines to ensure appropriate and prudent investment practices.

Investment Strategies

Detailed below is a description of the investment strategies for each major asset category for the pension and other postretirement benefit plans disclosed above:

- ***Domestic equity.*** A mix of large and small capitalization stocks with generally an equal distribution of value and growth attributes, managed both actively and through passive index approaches.
- ***International equity.*** A mix of growth stocks and value stocks with both developed and emerging market exposure, managed both actively and through passive index approaches.
- ***Fixed income.*** A mix of domestic and international bonds.
- ***Special situations.*** Investments in opportunistic strategies with the objective of diversifying and enhancing returns and exploiting short-term inefficiencies as well as investments in promising new strategies of a longer-term nature.
- ***Real estate investments.*** Investments in traditional private market, equity-oriented investments in real properties (indirectly through pooled funds or partnerships) and in publicly traded real estate securities.
- ***Private equity.*** Investments in private partnerships that invest in private or public securities typically through privately-negotiated and/or structured transactions, including leveraged buyouts, venture capital, and distressed debt.

Benefit Plan Asset Fair Values

Following are the fair value measurements for the pension plan and the other postretirement benefit plan assets as of December 31, 2012 and 2011. The fair values presented are prepared in accordance with GAAP. For purposes of determining the fair value of the pension plan and other postretirement benefit plan assets and the appropriate level designation, management relies on information provided by the plan's trustee. This information is reviewed and evaluated by management with changes made to the trustee information as appropriate.

Valuation methods of the primary fair value measurements disclosed in the following tables are as follows:

- **Investments in equity securities:** Investments in equity securities such as common stocks, American depositary receipts, and real estate investment trusts that trade on a public exchange are classified as Level 1 investments and are valued at the closing price in the active market. Equity investments with unpublished prices (i.e. pooled funds) are valued as Level 2, when the underlying holdings used to value the investment are comprised of Level 1 or Level 2 equity securities.
- **Investments in fixed income securities:** Investments in fixed income securities are generally classified as Level 2 investments and are valued based on prices reported in the market place. Additionally, the value of fixed income securities takes into consideration certain items such as broker quotes, spreads, yield curves, interest rates, and discount rates that apply to the term of a specific instrument.
- **Investments in private equity and real estate:** Investments in private equity and real estate are generally classified as Level 3 as the underlying assets typically do not have observable inputs. The fund manager values the assets using various inputs and techniques depending on the nature of the underlying investments. In the case of private equity, techniques may include purchase multiples for comparable transactions, comparable public company trading multiples, and discounted cash flow analysis. Real estate managers generally use prevailing market capitalization rates, recent sales of comparable investments, and independent third-party appraisals to value underlying real estate investments. The fair value of partnerships is determined by aggregating the value of the underlying assets.

The fair values of pension plan assets as of December 31, 2012 and 2011 are presented below. These fair value measurements exclude cash, receivables related to investment income, pending investments sales, and payables related to pending investment purchases. Assets that are considered special situations investments, primarily real estate investments and private equities, are presented in the tables below based on the nature of the investment.

	Fair Value Measurements Using			
As of December 31, 2012:	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
		(in thousands)		
Assets:				
Domestic equity*	$ 51,215	$ 29,499	$ —	$ 80,714
International equity*	40,166	43,120	—	83,286
Fixed income:				
U.S. Treasury, government, and agency bonds	—	22,724	—	22,724
Mortgage- and asset-backed securities	—	5,594	—	5,594
Corporate bonds	—	38,534	139	38,673
Pooled funds	—	17,581	—	17,581
Cash equivalents and other	208	24,148	—	24,356
Real estate investments	11,362	—	37,039	48,401
Private equity	—	—	26,129	26,129
Total	$ 102,951	$ 181,200	$ 63,307	$ 347,458

* Level 1 securities consist of actively traded stocks while Level 2 securities consist of pooled funds. Management believes that the portfolio is well-diversified with no significant concentrations of risk.

	Fair Value Measurements Using			
As of December 31, 2011:	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
		(in thousands)		
Assets:				
Domestic equity*	$ 51,686	$ 23,857	$ —	$ 75,543
International equity*	53,130	15,223	—	68,353
Fixed income:				
U.S. Treasury, government, and agency bonds	—	19,375	—	19,375
Mortgage- and asset-backed securities	—	6,047	—	6,047
Corporate bonds	—	37,274	120	37,394
Pooled funds	—	16,998	—	16,998
Cash equivalents and other	30	6,228	—	6,258
Real estate investments	9,838	—	34,989	44,827
Private equity	—	—	26,053	26,053
Total	$ 114,684	$ 125,002	$ 61,162	$ 300,848

* Level 1 securities consist of actively traded stocks while Level 2 securities consist of pooled funds. Management believes that the portfolio is well-diversified with no significant concentrations of risk.

Changes in the fair value measurement of the Level 3 items in the pension plan assets valued using significant unobservable inputs for the years ended December 31, 2012 and 2011 were as follows:

	2012		2011	
	Real Estate Investments	Private Equity	Real Estate Investments	Private Equity
	(in thousands)			
Beginning balance	$ 34,989	$ 26,053	$ 30,355	$ 28,727
Actual return on investments:				
Related to investments held at year end	1,918	44	3,021	(538)
Related to investments sold during the year	132	1,396	896	1,941
Total return on investments	2,050	1,440	3,917	1,403
Purchases, sales, and settlements	—	(1,364)	717	(4,077)
Transfers into/out of Level 3	—	—	—	—
Ending balance	$ 37,039	$ 26,129	$ 34,989	$ 26,053

The fair values of other postretirement benefit plan assets as of December 31, 2012 and 2011 are presented below. These fair value measurements exclude cash, receivables related to investment income, pending investments sales, and payables related to pending investment purchases. Assets that are considered special situations investments, primarily real estate investments and private equities, are presented in the tables below based on the nature of the investment.

	Fair Value Measurements Using			
As of December 31, 2012:	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
		(in thousands)		
Assets:				
Domestic equity*	$ 2,290	$ 1,319	$ —	$ 3,609
International equity*	1,795	1,928	—	3,723
Fixed income:				
U.S. Treasury, government, and agency bonds	—	1,016	—	1,016
Mortgage- and asset-backed securities	—	250	—	250
Corporate bonds	—	1,722	6	1,728
Pooled funds	—	1,298	—	1,298
Cash equivalents and other	9	1,078	—	1,087
Real estate investments	508	—	1,667	2,175
Private equity	—	15	1,155	1,170
Total	$ 4,602	$ 8,626	$ 2,828	$ 16,056

* Level 1 securities consist of actively traded stocks while Level 2 securities consist of pooled funds. Management believes that the portfolio is well-diversified with no significant concentrations of risk.

As of December 31, 2011:	Fair Value Measurements Using: Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
		(in thousands)		
Assets:				
Domestic equity*	$ 2,445	$ 1,128	$ —	$ 3,573
International equity*	2,511	719	—	3,230
Fixed income:				
U.S. Treasury, government, and agency bonds	—	918	—	918
Mortgage- and asset-backed securities	—	286	—	286
Corporate bonds	—	1,761	—	1,761
Pooled funds	—	1,328	—	1,328
Cash equivalents and other	1	295	—	296
Real estate investments	466	—	1,657	2,123
Private equity	—	—	1,232	1,232
Total	$ 5,423	$ 6,435	$ 2,889	$ 14,747

* Level 1 securities consist of actively traded stocks while Level 2 securities consist of pooled funds. Management believes that the portfolio is well-diversified with no significant concentrations of risk.

Changes in the fair value measurement of the Level 3 items in the other postretirement benefit plan assets valued using significant unobservable inputs for the years ended December 31, 2012 and 2011 were as follows:

	2012		2011	
	Real Estate Investments	Private Equity	Real Estate Investments	Private Equity
		(in thousands)		
Beginning balance	**$ 1,657**	**$ 1,232**	$ 1,452	$ 1,375
Actual return on investments:				
Related to investments held at year end	**107**	**(1)**	129	(26)
Related to investments sold during the year	**6**	**80**	42	77
Total return on investments	**113**	**79**	171	51
Purchases, sales, and settlements	**(103)**	**(156)**	34	(194)
Transfers into/out of Level 3	—	—	—	—
Ending balance	**$ 1,667**	**$ 1,155**	$ 1,657	$ 1,232

Employee Savings Plan

The Company also sponsors a 401(k) defined contribution plan covering substantially all employees. The Company provides an 85% matching contribution on up to 6% of an employee's base salary. Total matching contributions made to the plan for 2012, 2011, and 2010 were $4.0 million, $3.7 million, and $3.6 million, respectively.

3. CONTINGENCIES AND REGULATORY MATTERS

General Litigation Matters

The Company is subject to certain claims and legal actions arising in the ordinary course of business. In addition, the Company's business activities are subject to extensive governmental regulation related to public health and the environment, such as regulation of air emissions and water discharges. Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements such as air quality and water standards, has increased generally throughout the U.S. In particular, personal injury, property damage, and other claims for damages alleged to have been caused by carbon dioxide and other emissions, coal combustion byproducts, and alleged exposure to hazardous materials, and/or requests for injunctive relief in connection with such matters, have become more frequent. The ultimate outcome of such pending or potential litigation against the Company cannot be predicted at this time; however, for current proceedings not specifically reported herein, management does not anticipate that the ultimate liabilities, if any, arising from such current proceedings would have a material effect on the Company's financial statements.

Environmental Matters

New Source Review Actions

In 1999, the EPA brought a civil action in the U.S. District Court for the Northern District of Georgia against certain Southern Company subsidiaries, including Alabama Power and Georgia Power, alleging that these subsidiaries had violated the New Source Review (NSR) provisions of the Clean Air Act and related state laws at certain coal-fired generating facilities. The EPA alleged NSR violations at five coal-fired generating facilities operated by Alabama Power and three coal-fired generating facilities operated by Georgia Power, including a unit co-owned by the Company. The civil action sought penalties and injunctive relief, including an order requiring installation of the best available control technology at the affected units. These actions were filed concurrently with the issuance of notices of violation of the NSR provisions to the Company with respect to the Company's Plant Crist. The case against Georgia Power (including claims related to the unit co-owned by the Company) was administratively closed in 2001 and has not been reopened. After Alabama Power was dismissed from the original action, the EPA filed a separate action in 2001 against Alabama Power in the U.S. District Court for the Northern District of Alabama.

The Company believes it complied with applicable laws and regulations in effect at the time the work in question took place. The Clean Air Act authorizes maximum civil penalties of $25,000 to $37,500 per day, per violation, depending on the date of the alleged violation. An adverse outcome could require substantial capital expenditures that cannot be determined at this time and could possibly require payment of substantial penalties. Such expenditures could affect future results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates. The ultimate outcome of this matter cannot be determined at this time.

Climate Change Litigation

Kivalina Case

In 2008, the Native Village of Kivalina and the City of Kivalina filed a lawsuit in the U.S. District Court for the Northern District of California against several electric utilities (including Southern Company), several oil companies, and a coal company. The plaintiffs allege that the village is being destroyed by erosion allegedly caused by global warming that the plaintiffs attribute to emissions of greenhouse gases by the defendants. The plaintiffs assert claims for public and private nuisance and contend that some of the defendants (including Southern Company) acted in concert and are therefore jointly and severally liable for the plaintiffs' damages. The suit seeks damages for lost property values and for the cost of relocating the village, which is alleged to be $95 million to $400 million. In 2009, the U.S. District Court for the Northern District of California granted the defendants' motions to dismiss the case. On September 21, 2012, the U.S. Court of Appeals for the Ninth Circuit upheld the U.S. District Court for the Northern District of California's dismissal of the case. On November 27, 2012, the U.S. Court of Appeals for the Ninth Circuit denied the plaintiffs' request for review of the decision. On February 25, 2013, the plaintiffs filed a petition for writ of certiorari with the U.S. Supreme Court. Southern Company believes that these claims are without merit. While Southern Company believes the likelihood of loss is remote based on existing case law, it is not possible to predict with certainty whether the Company will incur any liability in connection with this matter. The ultimate outcome of this matter cannot be determined at this time.

Hurricane Katrina Case

In 2005, immediately following Hurricane Katrina, a lawsuit was filed in the U.S. District Court for the Southern District of Mississippi by Ned Comer on behalf of Mississippi residents seeking recovery for property damage and personal injuries caused by Hurricane Katrina. In 2006, the plaintiffs amended the complaint to include Southern Company and many other electric utilities, oil

companies, chemical companies, and coal producers. The plaintiffs allege that the defendants contributed to climate change, which contributed to the intensity of Hurricane Katrina. In 2007, the U.S. District Court for the Southern District of Mississippi dismissed the case. On appeal to the U.S. Court of Appeals for the Fifth Circuit, a three-judge panel reversed the U.S. District Court for the Southern District of Mississippi, holding that the case could proceed, but on rehearing, the full U.S. Court of Appeals for the Fifth Circuit dismissed the plaintiffs' appeal, resulting in reinstatement of the decision of the U.S. District Court for the Southern District of Mississippi in favor of the defendants. In May 2011, the plaintiffs filed an amended version of their class action complaint, arguing that the earlier dismissal was on procedural grounds and under Mississippi law the plaintiffs have a right to re-file. The amended complaint was also filed against numerous chemical, coal, oil, and utility companies, including the Company. On March 20, 2012, the U.S. District Court for the Southern District of Mississippi dismissed the plaintiffs' amended complaint. On April 16, 2012, the plaintiffs appealed the case to the U.S. Court of Appeals for the Fifth Circuit. The Company believes that these claims are without merit. While the Company believes the likelihood of loss is remote based on existing case law, it is not possible to predict with certainty whether the Company will incur any liability in connection with this matter. The ultimate outcome of this matter cannot be determined at this time.

Environmental Remediation

The Company must comply with environmental laws and regulations that cover the handling and disposal of waste and releases of hazardous substances. Under these various laws and regulations, the Company may also incur substantial costs to clean up properties. The Company received authority from the Florida PSC to recover approved environmental compliance costs through the environmental cost recovery clause. The Florida PSC reviews costs and adjusts rates up or down annually.

The Company recognizes a liability for environmental remediation costs only when it determines a loss is probable. At December 31, 2012, the Company's environmental remediation liability included estimated costs of environmental remediation projects of approximately $60.5 million. For 2012, approximately $2.6 million was included in under recovered regulatory clause revenues and other current liabilities, and approximately $57.9 million was included in other regulatory assets, deferred and other deferred credits and liabilities. These estimated costs relate to site closure criteria by the Florida Department of Environmental Protection (FDEP) for potential impacts to soil and groundwater from herbicide applications at the Company's substations. The schedule for completion of the remediation projects will be subject to FDEP approval. The projects have been approved by the Florida PSC for recovery through the Company's environmental cost recovery clause; therefore, there was no impact on net income as a result of these liabilities.

The final outcome of these matters cannot be determined at this time. However, based on the currently known conditions at these sites and the nature and extent of activities relating to these sites, the Company does not believe that additional liabilities, if any, at these sites would be material to the Company's financial statements.

Retail Regulatory Matters

The Company's rates and charges for service to retail customers are subject to the regulatory oversight of the Florida PSC. The Company's rates are a combination of base rates and several separate cost recovery clauses for specific categories of costs. These separate cost recovery clauses address such items as fuel and purchased energy costs, purchased power capacity costs, energy conservation and demand side management programs, and the costs of compliance with environmental laws and regulations. Costs not addressed through one of the specific cost recovery clauses are recovered through the Company's base rates.

Retail Base Rate Case

On March 12, 2012, the Florida PSC approved an increase in retail base rates and charges of $64 million effective April 11, 2012. The amount of the increase includes the previously approved $38.5 million interim retail rate increase implemented in September 2011. The Florida PSC's decision on the amount of the increase also included a determination that none of the base rate revenues collected on an interim basis would be refunded. The Company's authorized retail ROE is a range of 9.25% to 11.25% with new retail base rates set at the midpoint retail ROE of 10.25%. In addition, the Florida PSC also approved a step increase to the Company's retail base rates and charges of $4 million effective in January 2013.

Cost Recovery Clauses

On November 5, 2012, the Florida PSC approved the Company's annual rate clause requests for its fuel, purchased power capacity, conservation, and environmental compliance cost recovery factors for 2013. The net effect of the approved changes is a 1.9% rate increase for residential customers using 1,000 KWHs per month.

Revenues for all cost recovery clauses, as recorded on the financial statements, are adjusted for differences in actual recoverable costs and amounts billed in current regulated rates. Accordingly, changes in the billing factor for fuel and purchased power will have no significant effect on the Company's revenues or net income, but will affect annual cash flow. The recovery provisions for environmental compliance and energy conservation include related expenses and a return on net average investment.

Fuel Cost Recovery

The Company has established fuel cost recovery rates as approved by the Florida PSC. If, at any time during the year, the projected year-end fuel cost over or under recovery balance exceeds 10% of the projected fuel revenue applicable for the period, the Company is required to notify the Florida PSC and indicate if an adjustment to the fuel cost recovery factor is being requested. On February 14, 2012, the Florida PSC approved a reduction to the fuel cost recovery factors starting in March 2012. The effect of the approved change was a 2.7% decrease for residential customers using 1,000 KWHs per month. On June 19, 2012, the Florida PSC approved an additional decrease in the Company's fuel rates lowering the 1,000 KWH residential bill 7.8% to reduce annual billings by approximately $58.8 million effective July 2, 2012.

The increase in the fuel cost over recovered balance during 2012 was primarily due to lower than expected fuel costs and purchased power energy expenses. At December 31, 2012 and 2011, the over recovered fuel balance was approximately $17.1 million and $9.9 million, respectively, which is included in other regulatory liabilities, current in the balance sheets.

Purchased Power Capacity Recovery

The Company has established purchased power capacity recovery cost rates as approved by the Florida PSC. If the projected year-end purchased power capacity cost over or under recovery balance exceeds 10% of the projected purchased power capacity revenue applicable for the period, the Company is required to notify the Florida PSC and indicate if an adjustment to the purchased power capacity cost recovery factor is being requested.

At December 31, 2012, the Company had an under recovered purchased power capacity balance of approximately $0.8 million, which is included in under recovered regulatory clause revenues in the balance sheets. At December 31, 2011, the Company had an over recovered purchased power capacity balance of approximately $8.0 million, which is included in other regulatory liabilities, current in the balance sheets.

Environmental Cost Recovery

The Florida Legislature adopted legislation for an environmental cost recovery clause, which allows an electric utility to petition the Florida PSC for recovery of prudent environmental compliance costs that are not being recovered through base rates or any other recovery mechanism. Such environmental costs include operations and maintenance expenses, emissions allowance expense, depreciation, and a return on net average investment. This legislation also allows recovery of costs incurred as a result of an agreement between the Company and the FDEP for the purpose of ensuring compliance with ozone ambient air quality standards adopted by the EPA.

In 2007, the Florida PSC voted to approve a stipulation among the Company, the Office of Public Counsel, and the Florida Industrial Power Users Group regarding the Company's plan for complying with certain federal and state regulations addressing air quality. The Company's environmental compliance plan as filed in 2007 contemplated implementation of specific projects identified in the plan from 2007 through 2018. The stipulation covers all elements of the original plan that were committed for implementation at the time of the stipulation. The Florida PSC's approval of the stipulation also required the Company to file annual updates to the plan and outlined a process for approval of additional elements in the plan when they became committed projects. In the 2010 update filing, the Company identified several elements of the updated plan that the Company had decided to implement. Following the process outlined in the original approved stipulation, these additional projects were approved by the Florida PSC later in 2010. The Florida PSC acknowledged that the costs of the approved projects associated with the Company's Clean Air Interstate Rule and Clean Air Visibility Rule compliance plans are eligible for recovery through the environmental cost recovery clause.

Annually, the Company seeks recovery of projected costs including any true-up amounts from prior periods. At December 31, 2012, the under recovered environmental balance was approximately $1.9 million, which is included in under recovered regulatory clause revenues in the balance sheets. At December 31, 2011, the over recovered environmental balance was approximately $10.0 million, which is included in other regulatory liabilities, current in the balance sheets.

On April 3, 2012, the Mississippi PSC approved Mississippi Power's request for a certificate of public convenience and necessity to construct a flue gas desulfurization system (scrubber) on Plant Daniel Units 1 and 2. On May 3, 2012, the Sierra Club filed a notice of appeal of the order with the Chancery Court of Harrison County, Mississippi. These units are jointly owned by Mississippi Power and the Company, with 50% ownership each. The estimated total cost of the project is approximately $660 million, excluding AFUDC, and it is scheduled for completion in December 2015. The Company's portion of the cost is expected to be recovered through the environmental cost recovery clause. The ultimate outcome of this matter cannot be determined at this time.

Energy Conservation Cost Recovery

Every five years, the Florida PSC establishes new numeric conservation goals covering a 10-year period for utilities to reduce annual energy and seasonal peak demand using demand-side management (DSM) programs. After the goals are established, utilities develop plans and programs to meet the approved goals. The costs for these programs are recovered through rates established annually in the energy conservation cost recovery (ECCR) clause.

The most recent goal setting process established new DSM goals for the period 2010 through 2019. The new goals are significantly higher than the goals established in the previous five-year cycle due to a change in the cost-effectiveness test on which the Florida PSC relies to set the goals. The DSM program standards were approved in April 2011, which allow the Company to implement its DSM programs designed to meet the new goals. Several of these new programs were implemented in June 2011 and the costs related to these programs are reflected in the 2012 ECCR factor approved by the Florida PSC. Higher cost recovery rates and achievement of the new DSM goals may result in reduced sales of electricity which could negatively impact results of operations, cash flows, and financial condition if base rates cannot be adjusted on a timely basis.

At December 31, 2012 and 2011, the under recovered energy conservation balance was approximately $0.8 million and $3.1 million, respectively, which is included in under recovered regulatory clause revenues in the balance sheets.

4. JOINT OWNERSHIP AGREEMENTS

The Company and Mississippi Power jointly own Plant Daniel Units 1 and 2, which together represent capacity of 1,000 MWs. Plant Daniel is a generating plant located in Jackson County, Mississippi. In accordance with the operating agreement, Mississippi Power acts as the Company's agent with respect to the construction, operation, and maintenance of these units.

The Company and Georgia Power jointly own the 818 MWs capacity Plant Scherer Unit 3. Plant Scherer is a generating plant located near Forsyth, Georgia. In accordance with the operating agreement, Georgia Power acts as the Company's agent with respect to the construction, operation, and maintenance of the unit.

The Company's proportionate share of expenses related to both plants is included in the corresponding operating expense accounts in the statements of income and the Company is responsible for providing its own financing.

At December 31, 2012, the Company's percentage ownership and investment in these jointly owned facilities were as follows:

	Plant Scherer Unit 3 (coal)	Plant Daniel Units 1 & 2 (coal)
	(in thousands)	
Plant in service	$ 373,576 [(a)]	$ 277,440
Accumulated depreciation	117,181	165,120
Construction work in progress	8,763	69,774
Ownership	25%	50%

(a) Includes net plant acquisition adjustment of $2.3 million.

The Company's proportionate share of its plant operating expenses is included in the corresponding operating expenses in the statements of income and the Company is responsible for providing its own financing.

5. INCOME TAXES

On behalf of the Company, Southern Company files a consolidated federal income tax return and combined state income tax returns for the States of Alabama, Georgia, and Mississippi. In addition, the Company files a separate company income tax return for the State of Florida. Under a joint consolidated income tax allocation agreement, each subsidiary's current and deferred tax expense is computed on a stand-alone basis and no subsidiary is allocated more current expense than would be paid if it filed a separate income tax return. In accordance with Internal Revenue Service (IRS) regulations, each company is jointly and severally liable for the federal tax liability.

Current and Deferred Income Taxes

Details of income tax provisions are as follows:

	2012	2011	2010
		(in thousands)	
Federal -			
Current	$ (92,610)	$ (1,548)	$ (14,115)
Deferred	161,096	56,087	77,452
	68,486	54,539	63,337
State -			
Current .	(2,484)	(412)	2,948
Deferred	13,209	7,141	5,229
	10,725	6,729	8,177
Total	$ 79,211	$ 61,268	$ 71,514

The tax effects of temporary differences between the carrying amounts of assets and liabilities in the financial statements and their respective tax bases, which give rise to deferred tax assets and liabilities, are as follows:

	2012	2011
	(in thousands)	
Deferred tax liabilities-		
Accelerated depreciation	$ 696,502	$ 496,392
Pension and other employee benefits	28,579	25,268
Regulatory assets associated with employee benefit obligations	57,279	44,871
Regulatory assets associated with asset retirement obligations	6,502	4,345
Other	16,019	14,804
Total	804,881	585,680
Deferred tax assets-		
Federal effect of state deferred taxes	20,656	16,684
Postretirement benefits	17,905	16,769
Fuel recovery clause	6,922	2,531
Pension and other employee benefits	61,939	49,116
Property reserve	13,773	13,159
Other comprehensive loss	993	1,353
Asset retirement obligations	6,502	4,345
Alternative minimum tax carryforward	938	7,151
Other	28,273	20,191
Total	157,901	131,299
Net deferred tax liabilities	646,980	454,381
Portion included in current assets (liabilities), net	1,972	4,597
Accumulated deferred income taxes	$ 648,952	$ 458,978

At December 31, 2012, the tax-related regulatory assets to be recovered from customers were $50.5 million. These assets are primarily attributable to tax benefits that flowed through to customers in prior years, to deferred taxes previously recognized at rates lower than the current enacted tax law, and to taxes applicable to capitalized AFUDC.

At December 31, 2012, the tax-related regulatory liabilities to be credited to customers were $6.5 million. These liabilities are primarily attributable to deferred taxes previously recognized at rates higher than the current enacted tax law and to unamortized investment tax credits.

In accordance with regulatory requirements, deferred investment tax credits are amortized over the life of the related property with such amortization normally applied as a credit to reduce depreciation in the statements of income. Credits amortized in this manner amounted to $1.4 million in 2012, $1.3 million in 2011, and $1.5 million in 2010. At December 31, 2012, all investment tax credits available to reduce federal income taxes payable had been utilized.

In 2010, the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010 (Tax Relief Act) was signed into law. Major tax incentives in the Tax Relief Act include 100% bonus depreciation for property placed in service after September 8, 2010 and through 2011 (and for certain long-term production-period projects placed in service in 2012) and 50% bonus depreciation for property placed in service in 2012 (and for certain long-term production-period projects to be placed in service in 2013). The application of the bonus depreciation provisions in the Tax Relief Act significantly increased deferred tax liabilities related to accelerated depreciation.

Effective Tax Rate

A reconciliation of the federal statutory income tax rate to the effective income tax rate is as follows:

	2012	2011	2010
Federal statutory rate	**35.0%**	35.0%	35.0%
State income tax, net of federal deduction	**3.3**	2.5	2.7
Non-deductible book depreciation	**0.5**	0.5	0.3
Differences in prior years' deferred and current tax rates	**(0.2)**	(0.3)	(0.3)
AFUDC equity	**(0.9)**	(2.0)	(1.3)
Other, net	**(0.2)**	(0.2)	(0.5)
Effective income tax rate	**37.5%**	35.5%	35.9%

The increase in the 2012 effective tax rate is primarily the result of a decrease in AFUDC equity, which is not taxable, and a decrease in state tax credits.

Unrecognized Tax Benefits

For 2012, the total amount of unrecognized tax benefits increased by $2.1 million, resulting in a balance of $5.0 million as of December 31, 2012.

Changes during the year in unrecognized tax benefits were as follows:

	2012	2011	2010
		(in thousands)	
Unrecognized tax benefits at beginning of year	**$ 2,892**	$ 3,870	$ 1,639
Tax positions from current periods	**2,630**	540	1,027
Tax positions from prior periods	**515**	(1,518)	1,204
Reductions due to settlements	**(1,030)**	—	—
Balance at end of year	**$ 5,007**	$ 2,892	$ 3,870

The tax positions increase from current periods for 2012 relates primarily to the tax accounting method change for repairs-generation assets. The tax positions increase from prior periods for 2012 also relates primarily to the tax accounting method change for repairs-generation assets. See "Tax Method of Accounting for Repairs" herein for additional information. The American Jobs Creation Act of 2004 created a tax deduction for a portion of income attributable to U.S. production activities as defined in Section 199 of the Internal Revenue Code (production activities deduction). The reductions due to settlements for 2012 relate to a settlement with the IRS of the calculation methodology for the production activities deduction.

The impact on the Company's effective tax rate, if recognized, was as follows:

	2012	2011	2010
		(in thousands)	
Tax positions impacting the effective tax rate	**$ 45**	$ 1,804	$ 1,826
Tax positions not impacting the effective tax rate	**4,962**	1,088	2,044
Balance of unrecognized tax benefits	**$ 5,007**	$ 2,892	$ 3,870

The tax positions impacting the effective tax rate for 2012 relate primarily to the research and development credit. The tax positions not impacting the effective tax rate for 2012 relate to the timing difference associated with the tax accounting method change for repairs-generation assets. See "Tax Method of Accounting for Repairs" herein for additional information. These amounts are presented on a gross basis without considering the related federal or state income tax impact.

Accrued interest for unrecognized tax benefits was as follows:

	2012	2011	2010
		(in thousands)	
Interest accrued at beginning of year	$ 283	$ 210	$ 90
Interest reclassified due to settlements	(283)	—	—
Interest accrued during the year	—	73	120
Balance at end of year	$ —	$ 283	$ 210

The Company classifies interest on tax uncertainties as interest expense. The Company did not accrue any penalties on uncertain tax positions.

It is reasonably possible that the amount of the unrecognized tax benefits associated with a majority of the Company's unrecognized tax positions will significantly increase or decrease within 12 months. The resolution of the tax accounting method change for repairs-generation assets, as well as the conclusion or settlement of state audits, could impact the balances significantly. At this time, an estimate of the range of reasonably possible outcomes cannot be determined.

The IRS has audited and closed all of Southern Company's consolidated federal income tax returns prior to 2009 and has settled its audits of Southern Company's consolidated federal income tax returns for 2009 and 2010, in principle, pending final approval. Additionally, the IRS has audited and closed Southern Company's 2011 consolidated federal income tax return. For tax years 2010 through 2013, Southern Company is a participant in the Compliance Assurance Process of the IRS. The audits for the Company's state income tax returns have either been concluded, or the statute of limitations has expired, for years prior to 2007.

Tax Method of Accounting for Repairs

Southern Company submitted a tax accounting method change related to the deductibility of repair costs associated with its subsidiaries' generation, transmission, and distribution systems effective for the 2009 consolidated federal income tax return in 2010. In August 2011, the IRS issued a revenue procedure, which provides a safe harbor method of accounting that taxpayers may use to determine eligible repair costs for transmission and distribution property. The IRS continues to work with the utility industry in an effort to define eligible repair costs for generation assets in a consistent manner for all utilities. The IRS published regulations on the deduction and capitalization of expenditures related to tangible property that generally apply for tax years beginning on or after January 1, 2014. The utility industry anticipates more detailed guidance concerning these regulations. Due to the uncertainty regarding the ultimate resolution of the repair costs for generation assets, an unrecognized tax position has been recorded for the tax accounting method change for repairs-generation assets. The ultimate outcome of this matter cannot be determined at this time; however, it is not expected to materially impact net income.

6. FINANCING

Securities Due Within One Year

Approximately $60 million will be required through December 31, 2013 to fund maturities of long-term debt.

Maturities from 2014 through 2017 applicable to total long-term debt are as follows: $75 million in 2014; $110 million in 2016; and $85 million in 2017. There are no scheduled maturities in 2015.

Senior Notes

At December 31, 2012 and 2011, the Company had a total of $945 million and $936.4 million of senior notes outstanding, respectively. These senior notes are effectively subordinate to all secured debt of the Company, which totals approximately $41 million at December 31, 2012.

In May 2012, the Company issued $100 million aggregate principal amount of Series 2012A 3.10% Senior Notes due May 15, 2022. The net proceeds from the sale of the Series 2012A Senior Notes were used to redeem all of approximately $61 million aggregate principal amount of the Company's Series F 5.60% Senior Insured Quarterly Notes due April 1, 2033 and $30 million aggregate principal amount of the Company's Series H 5.25% Senior Notes due July 15, 2033, to repay a portion of the Company's outstanding short-term indebtedness, and for general corporate purposes, including the Company's continuous construction program.

Pollution Control Revenue Bonds

Pollution control obligations represent loans to the Company from public authorities of funds derived from sales by such authorities of revenue bonds issued to finance pollution control and solid waste disposal facilities. The Company is required to make payments sufficient for the authorities to meet principal and interest requirements of such bonds. The amount of tax-exempt pollution control revenue bonds outstanding at December 31, 2012 and 2011 was $309 million.

In November 2012, the Mississippi Business Finance Corporation issued $13 million aggregate principal amount of Mississippi Business Finance Corporation Solid Waste Disposal Facilities Revenue Refunding Bonds, Series 2012 (Gulf Power Company Project), due November 1, 2042 for the benefit of the Company. The proceeds were used in December 2012 to redeem the Mississippi Business Finance Corporation Solid Waste Disposal Facilities Revenue Refunding Bonds, Series 2002 (Gulf Power Company Project), due September 1, 2028.

Outstanding Classes of Capital Stock

The Company currently has preferred stock, Class A preferred stock, preference stock, and common stock authorized. The Company's preferred stock and Class A preferred stock, without preference between classes, rank senior to the Company's preference stock and common stock with respect to payment of dividends and voluntary or involuntary dissolution. No shares of preferred stock or Class A preferred stock were outstanding at December 31, 2012. The Company's preference stock ranks senior to the common stock with respect to the payment of dividends and voluntary or involuntary dissolution. Certain series of the preference stock are subject to redemption at the option of the Company on or after a specified date (typically five or 10 years after the date of issuance) at a redemption price equal to 100% of the liquidation amount of the preference stock. In addition, one series of the preference stock may be redeemed earlier at a redemption price equal to 100% of the liquidation amount plus a make-whole premium based on the present value of the liquidation amount and future dividends.

In January 2012, the Company issued to Southern Company 400,000 shares of the Company's common stock, without par value, and realized proceeds of $40 million. Subsequent to December 31, 2012, the Company issued to Southern Company 400,000 shares of the Company's common stock, without par value, and realized proceeds of $40 million. The proceeds were used to repay a portion of the Company's short-term debt and for other general corporate purposes, including the Company's continuous construction program.

Dividend Restrictions

The Company can only pay dividends to Southern Company out of retained earnings or paid-in-capital.

Assets Subject to Lien

The Company has granted a lien on its property at Plant Daniel in connection with the issuance of two series of pollution control revenue bonds with an outstanding principal amount of $41 million. There are no agreements or other arrangements among the Southern Company system companies under which the assets of one company have been pledged or otherwise made available to satisfy obligations of Southern Company or any of its subsidiaries.

Bank Credit Arrangements

At December 31, 2012, committed credit arrangements with banks were as follows:

Expires[a]				Executable Term-Loans		Due Within One Year	
2013	2014	Total	Unused	One Year	Two Years	Term Out	No Term Out
$ 80	$ 195	$ 275	$ 275	$ 45	$ —	$ 45	$ 35

(a) No credit arrangements expire after 2014.

During 2012, the Company renewed a $30 million credit arrangement and changed the terms of the credit arrangement so that it expires after two years instead of one year, which is reflected in the table above. The Company expects to renew its credit arrangements, as needed, prior to expiration. Of the $275 million of unused credit arrangements, $69 million provides support for variable rate pollution control revenue bonds and $206 million was available for liquidity support for the Company's commercial paper program and for other general corporate purposes. Most of the credit arrangements require payment of commitment fees based on the unused portion of the commitments. Commitment fees average less than 1/4 of 1% for the Company.

Most of those credit arrangements with banks contain covenants that limit the Company's debt level to 65% of total capitalization, as defined in the arrangements. At December 31, 2012, the Company was in compliance with these covenants.

In addition, the credit arrangements typically contain cross default provisions that are restricted only to indebtedness of the Company. The Company is currently in compliance with all such covenants.

For short-term cash needs, the Company borrows primarily through a commercial paper program that has the liquidity support of the Company's committed bank credit arrangements. The Company may also borrow through various other arrangements with banks. Commercial paper and short-term bank loans are included in notes payable in the balance sheets.

Details of short-term borrowings included in notes payable on the balance sheets were as follows:

	Short-term Debt at the End of the Period [a]	
	Amount Outstanding	Weighted Average Interest Rate
	(in millions)	
December 31, 2012:		
Commercial paper	$ 124	0.3%
December 31, 2011:		
Commercial paper	$ 111	0.2%

(a) Excludes notes payable related to other energy service contracts of $3.2 million and $3.6 million for the periods ended December 31, 2012 and 2011, respectively.

7. COMMITMENTS

Fuel and Purchased Power Agreements

To supply a portion of the fuel requirements of its generating plants, the Company has entered into various long-term commitments for the procurement of fossil fuel which are not recognized on the balance sheets. In 2012, 2011, and 2010, the Company incurred fuel expense of $544.9 million, $662.3 million, and $742.3 million, the majority of which was purchased under long-term commitments. The Company expects that a substantial amount of its future fuel needs will continue to be purchased under long-term commitments.

In addition, the Company has entered into various long-term commitments for the purchase of capacity, energy, and transmission, some of which are accounted for as operating leases. The energy-related costs associated with PPAs are recovered through the fuel cost recovery clause. The capacity and transmission-related costs associated with PPAs are recovered through the purchased power capacity cost recovery clause. Capacity expense under purchased power agreements accounted for as operating leases was $24.6 million, $25.1 million, and $25.1 million for 2012, 2011, and 2010, respectively.

Estimated total minimum long-term commitments at December 31, 2012 were as follows:

	Operating Lease PPAs
	(in millions)
2013	$ 24.7
2014	52.9
2015	78.6
2016	78.7
2017	78.8
2018 and thereafter	428.1
Total	**$ 741.8**

SCS may enter into various types of wholesale energy and natural gas contracts acting as an agent for the Company and all of the other Southern Company traditional operating companies and Southern Power. Under these agreements, each of the traditional operating companies and Southern Power may be jointly and severally liable. The credit rating of Southern Power is currently below that of the traditional operating companies. Accordingly, Southern Company has entered into keep-well agreements with the Company and each of the other traditional operating companies to ensure the Company will not subsidize or be responsible for any costs, losses, liabilities, or damages resulting from the inclusion of Southern Power as a contracting party under these agreements.

Operating Leases

The Company has operating lease agreements with various terms and expiration dates. Total rent expense was $20.1 million, $21.9 million, and $23.1 million for 2012, 2011, and 2010, respectively.

Estimated total minimum lease payments under operating leases at December 31, 2012 were as follows:

	Minimum Lease Payments		
	Barges & Railcars	Other	Total
		(in millions)	
2013	$ 18.6	$ 0.3	$ 18.9
2014	17.2	0.3	17.5
2015	1.1	0.1	1.2
2016	0.9	0.1	1.0
2017	1.0	0.1	1.1
2018 and thereafter	—	—	—
Total	**$ 38.8**	**$ 0.9**	**$ 39.7**

The Company and Mississippi Power jointly entered into operating lease agreements for aluminum railcars for the transportation of coal to Plant Daniel. The Company has the option to purchase the railcars at the greater of lease termination value or fair market value or to renew the leases at the end of each lease term. The Company and Mississippi Power also have separate lease agreements for other railcars that do not include purchase options. The Company's share of the lease costs, charged to fuel inventory and recovered through the fuel cost recovery clause, was $3.6 million in 2012, $2.6 million in 2011, and $3.5 million in 2010. The Company's annual railcar lease payments for 2013 through 2017 will average approximately $1.6 million. The Company has no lease payment obligations for the period 2018 and thereafter.

8. STOCK COMPENSATION

Stock Options

Southern Company provides non-qualified stock options through its Omnibus Incentive Compensation Plan to a large segment of the Company's employees ranging from line management to executives. As of December 31, 2012, there were 218 current and former employees of the Company participating in the stock option program, and there were 39 million shares of Southern Company common stock remaining available for awards under the Omnibus Incentive Compensation Plan. The prices of options were at the fair market value of the shares on the dates of grant. These options become exercisable pro rata over a maximum period of three years from the date of grant. The Company generally recognizes stock option expense on a straight-line basis over the vesting period which equates to the requisite service period; however, for employees who are eligible for retirement, the total cost is expensed at the grant date. Options outstanding will expire no later than 10 years after the date of grant, unless terminated earlier by the Southern Company Board of Directors in accordance with the Omnibus Incentive Compensation Plan. For certain stock option awards, a change in control will provide accelerated vesting.

The estimated fair values of stock options granted were derived using the Black-Scholes stock option pricing model. Expected volatility was based on historical volatility of Southern Company's stock over a period equal to the expected term.

Southern Company used historical exercise data to estimate the expected term that represents the period of time that options granted to employees are expected to be outstanding. The risk-free rate was based on the U.S. Treasury yield curve in effect at the time of grant that covers the expected term of the stock options.

The following table shows the assumptions used in the pricing model and the weighted average grant-date fair value of stock options granted:

Year Ended December 31	2012	2011	2010
Expected volatility	**17.7%**	17.5%	17.4%
Expected term *(in years)*	**5.0**	5.0	5.0
Interest rate	**0.9%**	2.3%	2.4%
Dividend yield	**4.2%**	4.8%	5.6%
Weighted average grant-date fair value	**$3.39**	$3.23	$2.23

The Company's activity in the stock option program for 2012 is summarized below:

	Shares Subject to Option	Weighted Average Exercise Price
Outstanding at December 31, 2011	1,498,663	$ 33.75
Granted	244,607	44.43
Exercised	(353,749)	31.97
Cancelled	(606)	42.08
Outstanding at December 31, 2012	**1,388,915**	**$ 36.08**
Exercisable at December 31, 2012	**884,888**	**$ 34.02**

The number of stock options vested, and expected to vest in the future, as of December 31, 2012, was not significantly different from the number of stock options outstanding at December 31, 2012 as stated above. As of December 31, 2012, the weighted average remaining contractual term for the options outstanding and options exercisable was approximately six years and five years, respectively, and the aggregate intrinsic value for the options outstanding and options exercisable was $9.7 million and $7.8 million, respectively.

As of December 31, 2012, there was $0.3 million of total unrecognized compensation cost related to stock option awards not yet vested. That cost is expected to be recognized over a weighted average period of approximately 11 months.

For the years ended December 31, 2012, 2011, and 2010, total compensation cost for stock option awards recognized in income was $0.7 million, $0.7 million, and $0.8 million, respectively, with the related tax benefit also recognized in income of $0.3 million, $0.3 million, and $0.3 million, respectively.

The compensation cost and tax benefits related to the grant and exercise of Southern Company stock options to the Company's employees are recognized in the Company's financial statements with a corresponding credit to equity, representing a capital contribution from Southern Company.

The total intrinsic value of options exercised during the years ended December 31, 2012, 2011, and 2010 was $3.8 million, $3.2 million, and $1.6 million, respectively. The actual tax benefit realized by the Company for the tax deductions from stock option exercises totaled $1.5 million, $1.2 million, and $0.6 million for the years ended December 31, 2012, 2011, and 2010, respectively.

Performance Shares

Southern Company provides performance share award units through its Omnibus Incentive Compensation Plan to a large segment of the Company's employees ranging from line management to executives. The performance share units granted under the plan vest at the end of a three-year performance period which equates to the requisite service period. Employees that retire prior to the end of the three-year period receive a pro rata number of shares, issued at the end of the performance period, based on actual months of service prior to retirement. The value of the award units is based on Southern Company's total shareholder return (TSR) over the three-year performance period which measures Southern Company's relative performance against a group of industry peers. The performance shares are delivered in common stock following the end of the performance period based on Southern Company's actual TSR and may range from 0% to 200% of the original target performance share amount.

The fair value of performance share awards is determined as of the grant date using a Monte Carlo simulation model to estimate the TSR of Southern Company's stock among the industry peers over the performance period. The Company recognizes compensation expense on a straight-line basis over the three-year performance period without remeasurement. Compensation expense for awards where the service condition is met is recognized regardless of the actual number of shares issued. The expected volatility was based on the historical volatility of Southern Company's stock over a period equal to the performance period. The risk-free rate was based on the U.S. Treasury yield curve in effect at the time of grant that covers the performance period of the award units.

The following table shows the assumptions used in the pricing model and the weighted average grant-date fair value of performance share award units granted:

Year Ended December 31	2012	2011	2010
Expected volatility	**16.0%**	19.2%	20.7%
Expected term *(in years)*	**3.0**	3.0	3.0
Interest rate	**0.4%**	1.4%	1.4%
Annualized dividend rate	**$1.89**	$1.82	$1.75
Weighted average grant-date fair value	**$41.99**	$35.97	$30.13

Total unvested performance share units outstanding as of December 31, 2011 were 66,662. During 2012, 29,444 performance share units were granted, 26,738 performance share units were vested, and 563 performance share units were forfeited resulting in 68,805 unvested units outstanding at December 31, 2012. In January 2013, the vested performance share award units were converted into 36,105 shares outstanding at a share price of $43.05 for the three-year performance and vesting period ended December 31, 2012.

For the years ended December 31, 2012, 2011, and 2010, total compensation cost for performance share units recognized in income was $1.0 million, $0.7 million, and $0.3 million, respectively, with the related tax benefit also recognized in income of $0.4 million, $0.3 million, and $0.1 million, respectively. As of December 31, 2012, there was $1.0 million of total unrecognized compensation cost related to performance share award units that will be recognized over a weighted average period of approximately 11 months.

9. FAIR VALUE MEASUREMENTS

Fair value measurements are based on inputs of observable and unobservable market data that a market participant would use in pricing the asset or liability. The use of observable inputs is maximized where available and the use of unobservable inputs is minimized for fair value measurement and reflects a three-tier fair value hierarchy that prioritizes inputs to valuation techniques used for fair value measurement.

- Level 1 consists of observable market data in an active market for identical assets or liabilities.
- Level 2 consists of observable market data, other than that included in Level 1, that is either directly or indirectly observable.
- Level 3 consists of unobservable market data. The input may reflect the assumptions of the Company of what a market participant would use in pricing an asset or liability. If there is little available market data, then the Company's own assumptions are the best available information.

In the case of multiple inputs being used in a fair value measurement, the lowest level input that is significant to the fair value measurement represents the level in the fair value hierarchy in which the fair value measurement is reported.

As of December 31, 2012, assets and liabilities measured at fair value on a recurring basis during the period, together with the level of the fair value hierarchy in which they fall, were as follows:

	Fair Value Measurements Using			
As of December 31, 2012:	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Total**
		(in thousands)		
Assets:				
Energy-related derivatives	$ —	$ 4,358	$ —	$ 4,358
Cash equivalents	15,231	—	—	15,231
Total	$ 15,231	$ 4,358	$ —	$ 19,589
Liabilities:				
Energy-related derivatives	$ —	$ 27,112	$ —	$ 27,112

As of December 31, 2011, assets and liabilities measured at fair value on a recurring basis during the period, together with the level of the fair value hierarchy in which they fall, were as follows:

	Fair Value Measurements Using			
As of December 31, 2011:	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Total**
		(in thousands)		
Assets:				
Energy-related derivatives	$ —	$ 198	$ —	$ 198
Cash equivalents	13,949	—	—	13,949
Total	$ 13,949	$ 198	$ —	$ 14,147
Liabilities:				
Energy-related derivatives	$ —	$ 40,983	$ —	$ 40,983

Valuation Methodologies

The energy-related derivatives primarily consist of over-the-counter financial products for natural gas and physical power products including, from time to time, basis swaps. These are standard products used within the energy industry and are valued using the market approach. The inputs used are mainly from observable market sources, such as forward natural gas prices, power prices, implied volatility, and London Interbank Offered Rate interest rates. See Note 10 for additional information on how these derivatives are used.

As of December 31, 2012 and 2011, the fair value measurements of investments calculated at net asset value per share (or its equivalent), as well as the nature and risks of those investments, were as follows:

	Fair Value	Unfunded Commitments	Redemption Frequency	Redemption Notice Period
As of December 31, 2012:	*(in thousands)*			
Cash equivalents:				
Money market funds	$15,231	None	Daily	Not applicable
As of December 31, 2011:				
Cash equivalents:				
Money market funds	$13,949	None	Daily	Not applicable

The money market funds are short-term investments of excess funds in various money market mutual funds, which are portfolios of short-term debt securities. The money market funds are regulated by the SEC and typically receive the highest rating from credit rating agencies. Regulatory and rating agency requirements for money market funds include minimum credit ratings and maximum maturities for individual securities and a maximum weighted average portfolio maturity. Redemptions are available on a same day basis up to the full amount of the Company's investment in the money market funds.

As of December 31, 2012 and 2011, other financial instruments for which the carrying amount did not equal fair value were as follows:

	Carrying Amount	Fair Value
	(in thousands)	
Long-term debt:		
2012	**$ 1,245,870**	**$ 1,367,404**
2011	$ 1,235,447	$ 1,350,237

The fair values are determined using Level 2 measurements and are based on quoted market prices for the same or similar issues or on the current rates offered to the Company.

10. DERIVATIVES

The Company is exposed to market risks, primarily commodity price risk and interest rate risk. To manage the volatility attributable to these exposures, the Company nets its exposures, where possible, to take advantage of natural offsets and may enter into various derivative transactions for the remaining exposures pursuant to the Company's policies in areas such as counterparty exposure and risk management practices. The Company's policy is that derivatives are to be used primarily for hedging purposes and mandates strict adherence to all applicable risk management policies. Derivative positions are monitored using techniques including, but not limited to, market valuation, value at risk, stress testing, and sensitivity analysis. Derivative instruments are recognized at fair value in the balance sheets as either assets or liabilities and are presented on a gross basis.

Energy-Related Derivatives

The Company enters into energy-related derivatives to hedge exposures to electricity, gas, and other fuel price changes. However, due to cost-based rate regulations and other various cost recovery mechanisms, the Company has limited exposure to market volatility in commodity fuel prices and prices of electricity. The Company manages fuel hedging programs, implemented per the guidelines of the Florida PSC, through the use of financial derivative contracts, which is expected to continue to mitigate price volatility.

To mitigate residual risks relative to movements in electricity prices, the Company may enter into physical fixed-price contracts for the purchase and sale of electricity through the wholesale electricity market. To mitigate residual risks relative to movements in gas prices, the Company may enter into fixed-price contracts for natural gas purchases; however, a significant portion of contracts are priced at market.

Energy-related derivative contracts are accounted for in one of two methods:

- *Regulatory Hedges* — Energy-related derivative contracts which are designated as regulatory hedges relate primarily to the Company's fuel hedging programs, where gains and losses are initially recorded as regulatory liabilities and assets, respectively, and then are included in fuel expense as the underlying fuel is used in operations and ultimately recovered through the fuel cost recovery clause.
- *Not Designated* — Gains and losses on energy-related derivative contracts that are not designated or fail to qualify as hedges are recognized in the statements of income as incurred.

Some energy-related derivative contracts require physical delivery as opposed to financial settlement, and this type of derivative is both common and prevalent within the electric industry. When an energy-related derivative contract is settled physically, any cumulative unrealized gain or loss is reversed and the contract price is recognized in the respective line item representing the actual price of the underlying goods being delivered.

At December 31, 2012, the net volume of energy-related derivative contracts for natural gas positions for the Company, together with the longest hedge date over which it is hedging its exposure to the variability in future cash flows for forecasted transactions and the longest date for derivatives not designated as hedges, were as follows:

Gas		
Net Purchased mmBtu*	**Longest Hedge Date**	**Longest Non-Hedge Date**
(in thousands)		
70,510	2017	—

* mmBtu — million British thermal units

Interest Rate Derivatives

The Company may also enter into interest rate derivatives to hedge exposure to changes in interest rates. Derivatives related to existing variable rate securities or forecasted transactions are accounted for as cash flow hedges where the effective portion of the derivatives' fair value gains or losses is recorded in OCI and is reclassified into earnings at the same time the hedged transactions affect earnings. The derivatives employed as hedging instruments are structured to minimize ineffectiveness, which is recorded directly to earnings.

At December 31, 2012, there were no interest rate derivatives outstanding.

The estimated pre-tax losses that will be reclassified from OCI to interest expense for the 12-month period ending December 31, 2013 are $0.8 million. The Company has deferred gains and losses that are expected to be amortized into earnings through 2020.

Derivative Financial Statement Presentation and Amounts

At December 31, 2012 and 2011, the fair value of energy-related derivatives was reflected in the balance sheets as follows:

	Asset Derivatives			Liability Derivatives		
Derivative Category	**Balance Sheet Location**	**2012**	2011	**Balance Sheet Location**	**2012**	2011
		(in thousands)			*(in thousands)*	
Derivatives designated as hedging instruments for regulatory purposes						
Energy-related derivatives:						
	Other current assets	**$ 1,293**	$ 154	Liabilities from risk management activities	**$ 16,529**	$ 22,786
	Other deferred charges and assets	**3,065**	44	Other deferred credits and liabilities	**10,583**	18,197
Total derivatives designated as hedging instruments for regulatory purposes		**$ 4,358**	$ 198		**$ 27,112**	$ 40,983
Derivatives not designated as hedging instruments						
Energy-related derivatives:						
	Other current assets	**$ —**	$ —	Liabilities from risk management activities	**$ —**	$ —
Total		**$ 4,358**	$ 198		**$ 27,112**	$ 40,983

All derivative instruments are measured at fair value. See Note 9 for additional information.

At December 31, 2012 and 2011, the pre-tax effects of unrealized derivative gains (losses) arising from energy-related derivative instruments designated as regulatory hedging instruments and deferred on the balance sheets were as follows:

	Unrealized Losses			Unrealized Gains		
Derivative Category	**Balance Sheet Location**	**2012**	2011	**Balance Sheet Location**	**2012**	2011
		(in thousands)			*(in thousands)*	
Energy-related derivatives:						
	Other regulatory assets, current	**$ (16,529)**	$ (22,786)	Other regulatory liabilities, current	**$ 1,293**	$ 154
	Other regulatory assets, deferred	**(10,583)**	(18,197)	Other regulatory liabilities, deferred	**3,065**	44
Total energy-related derivative gains (losses)		**$ (27,112)**	$ (40,983)		**$ 4,358**	$ 198

For the years ended December 31, 2012, 2011, and 2010, the pre-tax effects of interest rate derivatives designated as cash flow hedging instruments on the statements of income were as follows:

Derivatives in Cash Flow Hedging Relationships	Gain (Loss) Recognized in OCI on Derivative (Effective Portion)			Gain (Loss) Reclassified from Accumulated OCI into Income (Effective Portion)			
					Amount		
Derivative Category	2012	2011	2010	Statements of Income Location	2012	2011	2010
		(in thousands)				*(in thousands)*	
Interest rate derivatives				Interest expense, net of amounts capitalized			
	$ —	$ —	$ (1,405)		$ (933)	$ (933)	$ (974)

There was no material ineffectiveness recorded in earnings for any period presented.

For the years ended December 31, 2012, 2011, and 2010, the pre-tax effects of energy-related derivatives not designated as hedging instruments on the statements of income were not material.

Contingent Features

The Company does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. There are certain derivatives that could require collateral, but not accelerated payment, in the event of various credit rating changes of certain affiliated companies. At December 31, 2012, the fair value of derivative liabilities with contingent features was $4 million.

At December 31, 2012, the Company had no collateral posted with its derivative counterparties; however, because of the joint and several liability features underlying these derivatives, the maximum potential collateral requirements arising from the credit-risk-related contingent features, at a rating below BBB- and/or Baa3, were $15 million.

Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. The Company participates in certain agreements that could require collateral in the event that one or more Southern Company system power pool participants has a credit rating change to below investment grade.

11. QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

Summarized quarterly financial information for 2012 and 2011 is as follows:

Quarter Ended	Operating Revenues	Operating Income	Net Income After Dividends on Preference Stock
		(in thousands)	
March 2012	**$ 316,245**	**$ 49,098**	**$ 20,666**
June 2012	**370,208**	**71,465**	**34,963**
September 2012	**421,819**	**93,813**	**47,754**
December 2012	**331,490**	**53,818**	**22,549**
March 2011	$ 324,608	$ 32,044	$ 11,691
June 2011	399,265	67,387	33,352
September 2011	468,030	81,454	41,217
December 2011	327,909	43,839	18,745

The Company's business is influenced by seasonal weather conditions.

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	2012	2011	2010	2009	2008
Operating Revenues (in thousands)	**$ 1,439,762**	$ 1,519,812	$ 1,590,209	$ 1,302,229	$ 1,387,203
Net Income After Dividends on Preference Stock (in thousands)	**$ 125,932**	$ 105,005	$ 121,511	$ 111,233	$ 98,345
Cash Dividends on Common Stock (in thousands)	**$ 115,800**	$ 110,000	$ 104,300	$ 89,300	$ 81,700
Return on Average Common Equity (percent)	**10.92**	9.55	11.69	12.18	12.66
Total Assets (in thousands)	**$ 4,177,402**	$ 3,871,881	$ 3,584,939	$ 3,293,607	$ 2,879,025
Gross Property Additions (in thousands)	**$ 325,237**	$ 337,830	$ 285,379	$ 450,421	$ 390,744
Capitalization (in thousands):					
Common stock equity	**$ 1,180,742**	$ 1,124,948	$ 1,075,036	$ 1,004,292	$ 822,092
Preference stock	**97,998**	97,998	97,998	97,998	97,998
Long-term debt	**1,185,870**	1,235,447	1,114,398	978,914	849,265
Total (excluding amounts due within one year)	**$ 2,464,610**	$ 2,458,393	$ 2,287,432	$ 2,081,204	$ 1,769,355
Capitalization Ratios (percent):					
Common stock equity	**47.9**	45.8	47.0	48.3	46.5
Preference stock	**4.0**	4.0	4.3	4.7	5.5
Long-term debt	**48.1**	50.2	48.7	47.0	48.0
Total (excluding amounts due within one year)	**100.0**	100.0	100.0	100.0	100.0
Customers (year-end):					
Residential	**379,922**	378,248	376,561	374,091	373,595
Commercial	**53,808**	53,450	53,263	53,272	53,548
Industrial	**264**	273	272	279	287
Other	**577**	565	562	512	499
Total	**434,571**	432,536	430,658	428,154	427,929
Employees (year-end)	**1,416**	1,424	1,330	1,365	1,342

	2012	2011	2010	2009	2008
Operating Revenues (in thousands):					
Residential	$ 609,454	$ 637,352	$ 707,196	$ 588,073	$ 581,723
Commercial	389,936	408,389	439,468	376,125	369,625
Industrial	140,490	158,367	157,591	138,164	165,564
Other	4,591	4,382	4,471	4,206	3,854
Total retail	1,144,471	1,208,490	1,308,726	1,106,568	1,120,766
Wholesale — non-affiliates	106,881	133,555	109,172	94,105	97,065
Wholesale — affiliates	123,636	111,346	110,051	32,095	106,989
Total revenues from sales of electricity	1,374,988	1,453,391	1,527,949	1,232,768	1,324,820
Other revenues	64,774	66,421	62,260	69,461	62,383
Total	$ 1,439,762	$ 1,519,812	$ 1,590,209	$ 1,302,229	$ 1,387,203
Kilowatt-Hour Sales (in thousands):					
Residential	5,053,724	5,304,769	5,651,274	5,254,491	5,348,642
Commercial	3,858,521	3,911,399	3,996,502	3,896,105	3,960,923
Industrial	1,725,121	1,798,688	1,685,817	1,727,106	2,210,597
Other	25,267	25,430	25,602	25,121	23,237
Total retail	10,662,633	11,040,286	11,359,195	10,902,823	11,543,399
Wholesale — non-affiliates	977,395	2,012,986	1,675,079	1,813,592	1,816,839
Wholesale — affiliates	4,369,964	2,607,873	2,436,883	870,470	1,871,158
Total	16,009,992	15,661,145	15,471,157	13,586,885	15,231,396
Average Revenue Per Kilowatt-Hour (cents):					
Residential	12.06	12.01	12.51	11.19	10.88
Commercial	10.11	10.44	11.00	9.65	9.33
Industrial	8.14	8.80	9.35	8.00	7.49
Total retail	10.73	10.95	11.52	10.15	9.71
Wholesale	4.31	5.30	5.33	4.70	5.53
Total sales	8.59	9.28	9.88	9.07	8.70
Residential Average Annual Kilowatt-Hour Use Per Customer	13,303	14,028	15,036	14,049	14,274
Residential Average Annual Revenue Per Customer	$ 1,604	$ 1,685	$ 1,882	$ 1,572	$ 1,552
Plant Nameplate Capacity Ratings (year-end) (megawatts)	2,663	2,663	2,663	2,659	2,659
Maximum Peak-Hour Demand (megawatts):					
Winter	2,130	2,485	2,544	2,310	2,360
Summer	2,344	2,527	2,519	2,538	2,533
Annual Load Factor (percent)	56.3	54.5	56.1	53.8	56.7
Plant Availability Fossil-Steam (percent)*	82.5	84.7	94.7	89.7	88.6
Source of Energy Supply (percent):					
Coal	34.6	49.4	64.6	61.7	77.3
Gas	23.5	24.0	17.8	28.0	15.3
Purchased power —					
From non-affiliates	40.2	22.3	13.2	2.2	2.6
From affiliates	1.7	4.3	4.4	8.1	4.8
Total	100.0	100.0	100.0	100.0	100.0

* Beginning in 2012, plant availability is calculated as a weighted equivalent availability.

MISSISSIPPI POWER COMPANY

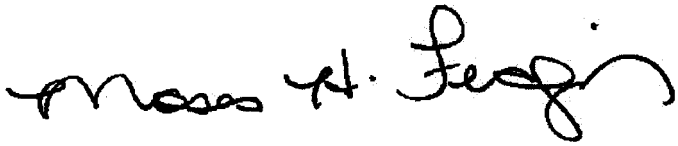
FINANCIAL SECTION

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING
Mississippi Power Company 2012 Annual Report

The management of Mississippi Power Company (the Company) is responsible for establishing and maintaining an adequate system of internal control over financial reporting as required by the Sarbanes-Oxley Act of 2002 and as defined in Exchange Act Rule 13a-15(f). A control system can provide only reasonable, not absolute, assurance that the objectives of the control system are met.

Under management's supervision, an evaluation of the design and effectiveness of the Company's internal control over financial reporting was conducted based on the framework in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, management concluded that the Company's internal control over financial reporting was effective as of December 31, 2012.

Edward Day, VI
President and Chief Executive Officer



Moses H. Feagin
Vice President, Treasurer, and Chief Financial Officer

February 27, 2013

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of
Mississippi Power Company

We have audited the accompanying balance sheets and statements of capitalization of Mississippi Power Company (the Company) (a wholly owned subsidiary of The Southern Company) as of December 31, 2012 and 2011, and the related statements of income, comprehensive income, common stockholder's equity, and cash flows for each of the three years in the period ended December 31, 2012. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such financial statements (pages II-389 to II-439) present fairly, in all material respects, the financial position of Mississippi Power Company as of December 31, 2012 and 2011, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2012, in conformity with accounting principles generally accepted in the United States of America.

Deloitte & Touche LLP

Atlanta, Georgia
February 27, 2013

OVERVIEW

Business Activities

Mississippi Power Company (the Company) operates as a vertically integrated utility providing electricity to retail customers within its traditional service territory located within the State of Mississippi and to wholesale customers in the Southeast.

Many factors affect the opportunities, challenges, and risks of the Company's business of selling electricity. These factors include the ability to maintain a constructive regulatory environment, to maintain and grow energy sales given economic conditions, and to effectively manage and secure timely recovery of rising costs. These costs include those related to projected long-term demand growth, increasingly stringent environmental standards, reliability, fuel, capital expenditures, and restoration following major storms. The Company has various regulatory mechanisms that operate to address cost recovery. Appropriately balancing required costs and capital expenditures with customer prices will continue to challenge the Company for the foreseeable future.

The Company's retail base rates are set under the Performance Evaluation Plan (PEP), a rate plan approved by the Mississippi Public Service Commission (PSC). PEP was designed with the objective to reduce the impact of rate changes on customers and provide incentives for the Company to keep customer prices low and customer satisfaction and reliability high.

In 2010, the Mississippi PSC issued a certificate of public convenience and necessity (CPCN) authorizing the acquisition, construction, and operation of a new integrated coal gasification combined cycle (IGCC) electric generating plant located in Kemper County, Mississippi (Kemper IGCC), which is scheduled to be placed into service in 2014.

On January 24, 2013, the Company and the Mississippi PSC entered into a settlement agreement (Settlement Agreement) that (i) establishes the process for resolving matters regarding cost recovery related to the Kemper IGCC for the purpose of mitigating risks to the Company and its customers and expediting the regulatory process associated with future rate filings required under the Settlement Agreement and (ii) resolves the Company's appeal before the Mississippi Supreme Court related to the new Certificated New Plant-A (CNP-A) rate schedule and stipulated rate increase submitted to the Mississippi PSC on June 14, 2012. The ultimate outcome of this matter cannot be determined at this time. See Note 3 to the financial statements under "Integrated Coal Gasification Combined Cycle" for additional information.

In October 2011, at the completion of the ten year operating lease, the Company purchased the combined cycle generating Units 3 and 4 at Plant Daniel (Plant Daniel Units 3 and 4) for $84.8 million in cash and the assumption of $270 million face value of debt obligations of the lessor related to Plant Daniel Units 3 and 4. See FINANCIAL CONDITION AND LIQUIDITY – "Purchase of the Plant Daniel Combined Cycle Generating Units" herein for additional information.

Key Performance Indicators

The Company continues to focus on several key performance indicators. These indicators are used to measure the Company's performance for customers and employees.

In recognition that the Company's long-term financial success is dependent upon how well it satisfies its customers' needs, the Company's retail base rate mechanism, PEP, includes performance indicators that directly tie customer service indicators to the Company's allowed return. PEP measures the Company's performance on a 10-point scale as a weighted average of results in three areas: average customer price, as compared to prices of other regional utilities (weighted at 40%); service reliability, measured in percentage of time customers had electric service (40%); and customer satisfaction, measured in a survey of residential customers (20%). See Note 3 to the financial statements under "Retail Regulatory Matters – Performance Evaluation Plan" for more information on PEP.

In addition to the PEP performance indicators, the Company focuses on other performance measures, including broader measures of customer satisfaction, plant availability, system reliability, and net income after dividends on preferred stock. The Company's financial success is directly tied to customer satisfaction. Key elements of ensuring customer satisfaction include outstanding service, high reliability, and competitive prices. Management uses customer satisfaction surveys and reliability indicators to evaluate the Company's results.

Peak season equivalent forced outage rate (Peak Season EFOR) is an indicator of fossil/hydro plant availability and efficient generation fleet operations during the months when generation needs are greatest. The rate is calculated by dividing the number of hours of forced outages by total generation hours. The 2012 fossil/hydro Peak Season EFOR was better than the target, excluding the impact of Hurricane Isaac in August 2012. Transmission and distribution system reliability performance is measured by the frequency and duration of outages. Performance targets for reliability are set internally based on historical performance. The 2012 performance was better than the target for these reliability measures.

Net income after dividends on preferred stock is the primary measure of the Company's financial performance. The Company was below target for 2012 net income after dividends on preferred stock primarily due to lower retail revenue under PEP and the Mississippi PSC denial of the 2012 rate recovery filings for the Kemper IGCC, partially offset by lower operations and maintenance expenses and higher allowance for funds used during construction (AFUDC) related to the construction of the Kemper IGCC, which began in 2010. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Performance Evaluation Plan" and FUTURE EARNINGS POTENTIAL – "PSC Matters – Certificated New Plant" herein for additional information.

The Company's 2012 results compared with its targets for some of these key indicators are reflected in the following chart:

Key Performance Indicator	2012 Target Performance	2012 Actual Performance
Customer Satisfaction	**Top quartile in customer surveys**	**Top quartile overall and in all segments**
Peak Season EFOR*	**4.99% or less**	**0.5%**
Net income after dividends on preferred stock	**$156.9 million**	**$148.1 million**

*Excluding impact of Hurricane Isaac

See RESULTS OF OPERATIONS herein for additional information on the Company's financial performance. Management continues to emphasize the importance of performing well and employees continue to demonstrate their commitment to achieving or exceeding management's expectations.

Earnings

The Company's net income after dividends on preferred stock was $148.1 million in 2012 compared to $94.2 million in 2011. The 57.3% increase in 2012 was primarily the result of increases in AFUDC equity related to the construction of the Kemper IGCC which began in 2010, a decrease in operations and maintenance expenses, and an increase in territorial base revenues primarily due to a wholesale base rate increase effective April 1, 2012. This increase in net income after dividends on preferred stock was partially offset by an increase in interest expense, net of amounts capitalized. See Note 3 to the financial statements under "Integrated Coal Gasification Combined Cycle" for additional information regarding the Kemper IGCC.

The Company's net income after dividends on preferred stock was $94.2 million in 2011 compared to $80.2 million in 2010. The 17.4% increase in 2011 was primarily the result of increases in AFUDC equity related to the construction of the Kemper IGCC. This increase in net income after dividends on preferred stock was partially offset by decreases in retail base revenues resulting from closer to normal weather in 2011 compared to 2010 and increased depreciation and amortization.

RESULTS OF OPERATIONS

A condensed statement of income follows:

	Amount	Increase (Decrease) from Prior Year	
	2012	2012	2011
		(in millions)	
Operating revenues	$ 1,036.0	$ (76.9)	$ (30.2)
Fuel	411.2	(79.2)	(11.4)
Purchased power	55.1	(16.7)	(11.9)
Other operations and maintenance	228.7	(37.7)	(1.7)
Depreciation and amortization	86.6	6.2	3.5
Taxes other than income taxes	79.4	9.3	0.3
Total operating expenses	861.0	(118.1)	(21.2)
Operating income	175.0	41.2	(9.0)
Allowance for equity funds used during construction	64.8	40.1	20.9
Interest income	0.7	(0.6)	1.1
Interest expense, net of amounts capitalized	40.8	19.1	(0.7)
Other income (expense), net	0.5	0.5	(3.8)
Income taxes	50.4	8.2	(4.1)
Net income	149.8	53.9	14.0
Dividends on preferred stock	1.7	—	—
Net income after dividends on preferred stock	$ 148.1	$ 53.9	$ 14.0

Operating Revenues

Operating revenues for 2012 were $1.0 billion, reflecting a $76.9 million decrease from 2011. Details of the Company's operating revenues in 2012 and the prior year were as follows:

	Amount	
	2012	2011
	(in millions)	
Retail — prior year	$ 792.5	$ 797.9
Estimated change in —		
Rates and pricing	(2.0)	0.5
Sales growth (decline)	9.0	2.3
Weather	(9.8)	(8.9)
Fuel and other cost recovery	(42.2)	0.7
Retail — current year	747.5	792.5
Wholesale revenues —		
Non-affiliates	255.5	273.2
Affiliates	16.4	30.4
Total wholesale revenues	271.9	303.6
Other operating revenues	16.6	16.8
Total operating revenues	$ 1,036.0	$ 1,112.9
Percent change	(6.9)%	(2.6)%

Total retail revenues for 2012 decreased 5.7% compared to 2011 primarily as a result of lower energy sales primarily due to milder weather and lower fuel cost recovery revenues in 2012 compared to 2011. Total retail revenues for 2011 decreased 0.7% compared to 2010 primarily as a result of lower energy sales due to closer to normal weather in 2011 compared to 2010. See "Energy Sales" below for a discussion of changes in the volume of energy sold, including changes related to sales growth (decline) and weather.

Electric rates for the Company include provisions to adjust billings for fluctuations in fuel costs, including the energy component of purchased power costs. Under these provisions, fuel revenues generally equal fuel expenses, including the energy component of purchased power costs, and do not affect net income. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Fuel Cost Recovery" herein for additional information. The fuel and other cost recovery revenues decreased in 2012 compared to 2011 primarily as a result of lower recoverable fuel costs, partially offset by an increase in revenues related to ad valorem taxes. The fuel and other cost recovery revenues increased in 2011 compared to 2010 primarily as a result of higher recoverable fuel costs. Recoverable fuel costs include fuel and purchased power expenses reduced by the fuel portion of wholesale revenues from energy sold to customers outside the Company's service territory.

Wholesale revenues from sales to non-affiliates will vary depending on fuel prices, the market prices of wholesale energy compared to the cost of the Company and the Southern Company system's generation, demand for energy within the Southern Company system's service territory, and the availability of the Southern Company system's generation. Increases and decreases in revenues that are driven by fuel prices are accompanied by an increase or decrease in fuel costs and do not have a significant impact on net income.

Wholesale revenues from sales to non-affiliates decreased $17.6 million, or 6.5%, in 2012 compared to 2011 as a result of a $31.0 million decrease in energy revenues, of which $23.2 million was associated with lower fuel prices and $7.8 million was associated with a decrease in kilowatt-hour (KWH) sales, partially offset by a wholesale base rate increase effective April 1, 2012. Wholesale revenues from sales to non-affiliates decreased $14.8 million, or 5.1%, in 2011 compared to 2010 as a result of a $13.4 million decrease in energy revenues, of which $11.4 million was associated with a decrease in KWH sales and $2.0 million was associated with lower fuel prices, and a $1.4 million decrease in capacity revenues resulting from the expiration of a power supply agreement in 2010, partially offset by a wholesale base rate increase effective January 2011.

Short-term opportunity energy sales are also included in sales for resale to non-affiliates. These opportunity sales are made at market-based rates that generally provide a margin above the Company's variable cost to produce the energy.

Wholesale revenues from sales to affiliated companies will vary from year to year depending on demand and the availability and cost of generating resources at each company. These affiliated sales and purchases are made in accordance with the Intercompany Interchange Contract (IIC), as approved by the Federal Energy Regulatory Commission (FERC). These transactions do not have a significant impact on earnings since this energy is generally sold at marginal cost.

Wholesale revenues from sales to affiliated companies decreased 46.1% in 2012 compared to 2011 primarily due to a $1.6 million decrease in capacity revenues and a $12.4 million decrease in energy revenues of which $9.1 million was associated with lower prices and $3.3 million was associated with a decrease in KWH sales. Wholesale revenues from sales to affiliated companies decreased 26.9% in 2011 compared to 2010 primarily due to a $2.5 million decrease in capacity revenues and an $8.7 million decrease in energy revenues of which $2.7 million was associated with lower prices and $6.0 million was associated with a decrease in KWH sales.

Other operating revenues in 2012 decreased $0.2 million, or 1.4%, from 2011 primarily due to a $1.0 million decrease in rent from electric property, partially offset by a $0.9 million increase in transmission revenues. Other operating revenues in 2011 increased $1.2 million, or 7.6%, from 2010 primarily due to a $1.8 million increase in transmission revenues.

Energy Sales

Changes in revenues are influenced heavily by the change in the volume of energy sold from year to year. KWH sales for 2012 and percent change by year were as follows:

	Total KWHs	Total KWH Percent Change		Weather-Adjusted Percent Change	
	2012	2012	2011	2012	2011
	(in millions)				
Residential	**2,046**	**(5.4)%**	(5.8)%	**2.3%**	(0.4)%
Commercial	**2,916**	**1.6**	(1.8)	**1.7**	2.1
Industrial	**4,702**	**2.5**	2.7	**2.5**	2.7
Other	**38**	**(0.2)**	0.3	**(0.2)**	0.3
Total retail	**9,702**	**0.5**	(0.7)	**2.2**	1.8
Wholesale					
Non-affiliated	**3,819**	**(4.8)**	(6.4)		
Affiliated	**572**	**(11.8)**	(16.2)		
Total wholesale	**4,391**	**(5.7)**	(7.9)		
Total energy sales	**14,093**	**(1.6)**	(3.1)		

Changes in retail energy sales are comprised of changes in electricity usage by customers, changes in weather, and changes in the number of customers.

Residential energy sales decreased 5.4% in 2012 compared to 2011 due to milder weather, partially offset by a slight increase in the number of residential customers in 2012 compared to 2011. Residential energy sales decreased 5.8% in 2011 compared to 2010 due to closer to normal weather in 2011 compared to 2010 and a slight decline in the number of residential customers in 2011.

Commercial energy sales increased 1.6% in 2012 compared to 2011 due to increased economic activity in 2012 compared to 2011. Commercial energy sales decreased 1.8% in 2011 compared to 2010 due to closer to normal weather in 2011 compared to 2010.

Industrial energy sales increased 2.5% in 2012 compared to 2011 due to increased production for many of the industrial customers resulting from increased economic activity as well as expansions of some existing customers. Industrial energy sales increased 2.7% in 2011 compared to 2010 due to increased production for many of the industrial customers resulting from an improving economy as well as expansions of some existing customers.

Wholesale energy sales to non-affiliates decreased 4.8% in 2012 compared to 2011 primarily due to decreased KWH sales to rural electric cooperative associations and municipalities located in southeastern Mississippi resulting from milder weather in 2012 compared to 2011. KWH sales to non-affiliates decreased 6.4% in 2011 compared to 2010 primarily due to decreased KWH sales to rural electric cooperative associations and municipalities located in southeastern Mississippi resulting from closer to normal weather in 2011 compared to 2010.

Wholesale sales to non-affiliates will vary depending on fuel prices, the market prices of wholesale energy compared to the cost of the Company and the Southern Company system's generation, demand for energy within the Southern Company system's service territory, and the availability of the Southern Company system's generation.

Wholesale energy sales to affiliates decreased 11.8% in 2012 compared to 2011 and 16.2% in 2011 compared to 2010 primarily due to a decrease in the Company's generation, resulting in less energy available to sell to affiliate companies.

Fuel and Purchased Power Expenses

Fuel costs constitute the single largest expense for the Company. The mix of fuel sources for generation of electricity is determined primarily by demand, the unit cost of fuel consumed, and the availability of generating units. Additionally, the Company purchases a portion of its electricity needs from the wholesale market.

Details of the Company's generation and purchased power were as follows:

	2012	2011	2010
Total generation *(millions of KWHs)*	**12,750**	12,986	13,146
Total purchased power *(millions of KWHs)*	**1,961**	2,055	2,330
Sources of generation *(percent)* –			
Coal	**26**	40	51
Gas	**74**	60	49
Cost of fuel, generated *(cents per net KWH)* –			
Coal	**5.09**	4.39	4.08
Gas	**2.90**	3.88	4.22
Average cost of fuel, generated *(cents per net KWH)*	**3.53**	4.10	4.14
Average cost of purchased power *(cents per net KWH)*	**2.81**	3.49	3.59

Fuel and purchased power expenses were $466.4 million in 2012, a decrease of $95.9 million, or 17.1% below the prior year costs. The decrease was primarily due to a $70.5 million decrease in the cost of fuel and purchased power and a $25.4 million decrease related to lower total KWHs generated and purchased. Fuel and purchased power expenses were $562.2 million in 2011, a decrease of $23.3 million, or 4.0%, below the prior year costs. The decrease was primarily due to a $16.5 million decrease related to lower total KWHs generated and purchased and a $6.8 million decrease in the cost of fuel and purchased power.

From an overall global market perspective, coal prices decreased from levels experienced in 2011 due to lower demand. In the U.S., this decrease was due primarily to relatively lower domestic natural gas prices that contributed to displacement of coal generation by natural gas-fueled generating units. The share of natural gas power production for the Company was higher than the share of coal-fired production. Lower domestic natural gas prices in 2012 were driven by continued robust supplies, including production from shale gas, and only modest increases in overall U.S. consumption.

Fuel and purchased power energy transactions do not have a significant impact on earnings, since energy expenses are generally offset by energy revenues through the Company's fuel cost recovery clause. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Fuel Cost Recovery" and Note 1 to the financial statements under "Fuel Costs" for additional information.

Fuel

Fuel expense decreased $79.2 million in 2012 compared to 2011. Approximately $66.2 million of the reduction in fuel expenses resulted primarily from lower fuel prices and a $13.0 million decrease in generation from Company-owned facilities. Fuel expense decreased $11.4 million in 2011 compared to 2010. Approximately $4.8 million of the reduction in fuel expenses resulted primarily from lower fuel prices and a $6.6 million decrease in generation from Company-owned facilities.

Purchased Power - Non-Affiliates

Purchased power expense from non-affiliates decreased $1.0 million, or 16.3%, in 2012 compared to 2011. The decrease was primarily the result of a 41.2% decrease in the average cost of purchased power per KWH, partially offset by a 42.3% increase in volume of KWHs purchased. The decrease in the average cost per KWH purchased was due to a lower marginal cost of fuel. The increase in the volume of KWHs purchased was due to a lower market cost of available energy compared to the cost of generation. Purchased power expense from non-affiliates decreased $2.2 million, or 26.0%, in 2011 compared to 2010. The decrease was primarily the result of a 32.4% decrease in the average cost of purchased power per KWH, partially offset by a 9.5% increase in volume of KWHs purchased.

Energy purchases from non-affiliates will vary depending on the market prices of wholesale energy compared to the cost of the Southern Company system's generation, demand for energy within the Southern Company system's service territory, and the availability of the Southern Company system's generation.

Purchased Power - Affiliates

Purchased power expense from affiliates decreased $15.7 million, or 23.9%, in 2012 compared to 2011. The decrease was primarily the result of a 15.4% decrease in the average cost of purchased power per KWH and a 10.0% decrease in volume of KWHs purchased. Purchased power expense from affiliates decreased $9.7 million, or 12.8%, in 2011 compared to 2010. The decrease was primarily the result of a 13.7% decrease in volume of KWHs purchased, partially offset by a 1.0% increase in the average cost of purchased power per KWH.

Energy purchases from affiliates will vary depending on demand for energy and the availability and cost of generating resources at each company within the Southern Company system. These purchases are made in accordance with the IIC, as approved by the FERC.

Other Operations and Maintenance Expenses

Other operations and maintenance expenses decreased $37.7 million in 2012 compared to 2011 primarily due to a $34.7 million decrease in rent expense and expenses under a long-term service agreement resulting from the expiration of the Plant Daniel Units 3 and 4 operating lease in October 2011 and a $6.3 million decrease in generation maintenance expenses for several major outages. These decreases were partially offset by a $2.8 million increase in administrative and general expenses. See FINANCIAL CONDITION AND LIQUIDITY – "Purchase of the Plant Daniel Combined Cycle Generating Units" herein for additional information.

Other operations and maintenance expenses decreased $1.7 million in 2011 compared to 2010 primarily due to a $4.0 million decrease in rent expense resulting from the expiration of the Plant Daniel Units 3 and 4 operating lease in October 2011 and a $4.6 million decrease in labor costs. These decreases were partially offset by a $4.2 million increase in generation maintenance expenses for several major outages, a $1.1 million increase in generation-related environmental expenses, and a $2.2 million increase in transmission and distribution expenses related to overhead line maintenance and vegetation maintenance costs.

Depreciation and Amortization

Depreciation and amortization increased $6.2 million in 2012 compared to 2011 primarily due to a $10.8 million increase in depreciation resulting from an increase in plant in service and a $6.2 million increase in amortization resulting from the plant acquisition adjustment related to the purchase of Plant Daniel Units 3 and 4, partially offset by a $4.5 million decrease in amortization resulting from a regulatory deferral associated with the purchase of Plant Daniel Units 3 and 4, a $3.3 million decrease in Environmental Compliance Overview (ECO) Plan amortization, and a $2.4 million decrease in amortization resulting from a regulatory deferral associated with operations and maintenance expenses that ended in 2011.

Depreciation and amortization increased $3.5 million in 2011 compared to 2010 primarily due to a $5.2 million increase in depreciation resulting from an increase in plant in service and a $1.5 million increase in amortization resulting from the plant acquisition adjustment related to the purchase of Plant Daniel Units 3 and 4, partially offset by a $2.5 million decrease in amortization resulting from a regulatory deferral associated with the purchase of Plant Daniel Units 3 and 4 and a $0.7 million decrease in ECO Plan amortization.

See Note 1 to the financial statements under "Depreciation and Amortization" and Note 3 to the financial statements under "Retail Regulatory Matters – Performance Evaluation Plan" and "Environmental Compliance Overview Plan" for additional information.

Taxes Other Than Income Taxes

Taxes other than income taxes increased $9.3 million in 2012 compared to 2011 primarily as a result of an $11.7 million increase in ad valorem taxes resulting from the expiration of a tax exemption related to Plant Daniel Units 3 and 4, partially offset by a $2.2 million decrease in franchise taxes and a $0.2 million decrease in payroll taxes. Taxes other than income taxes increased $0.3 million in 2011 compared to 2010 primarily as a result of a $0.9 million increase in franchise taxes and a $0.3 million increase in payroll taxes, partially offset by a $0.9 million decrease in ad valorem taxes.

The retail portion of ad valorem taxes is recoverable under the Company's ad valorem tax cost recovery clause and, therefore, does not affect net income.

Allowance for Funds Used During Construction Equity

AFUDC equity increased $40.1 million in 2012 as compared to 2011 and $20.9 million in 2011 as compared to 2010. These increases were primarily due to increases in construction work in progress (CWIP) related to the construction of the Kemper IGCC which began in 2010. See Note 3 to the financial statements under "Integrated Coal Gasification Combined Cycle" for additional information regarding the Kemper IGCC.

Interest Expense, Net of Amounts Capitalized

Interest expense, net of amounts capitalized increased $19.1 million in 2012 compared to 2011, primarily due to a $39.0 million increase in interest expense associated with the issuances of new long-term debt in October 2011, March 2012, August 2012, and November 2012, and a $12.5 million increase in interest expense resulting from the receipt of a $150.0 million interest-bearing refundable deposit from South Mississippi Electric Power Association (SMEPA) in March 2012 related to its pending purchase of an undivided interest in the Kemper IGCC. These increases were partially offset by a $22.8 million increase in capitalized interest primarily resulting from AFUDC debt associated with the Kemper IGCC, a $6.1 million decrease in interest expense resulting from the amortization of the fair value adjustment in the assumed debt related to the purchase of Plant Daniel Units 3 and 4 in October 2011, and a $3.5 million decrease in interest expense associated with the redemption of long term debt in 2012.

Interest expense, net of amounts capitalized, decreased $0.7 million in 2011 compared to 2010 primarily due to a $5.3 million increase in capitalized AFUDC debt associated with the Kemper IGCC, a $1.9 million decrease in interest expense due to deferred interest on the regulatory assets related to Plant Daniel Units 3 and 4 of $1.4 million and the Kemper IGCC of $0.5 million, and a $1.5 million decrease in interest expense resulting from the amortization of the fair value adjustment in the assumed debt related to the purchase of Plant Daniel Units 3 and 4. These decreases were partially offset by a $7.9 million increase in interest expense associated with the issuances of new long-term debt in December 2010, April 2011, September 2011, and October 2011.

Other Income (Expense), Net

Other income (expense), net increased $0.5 million in 2012 compared to 2011 primarily due to a $1.6 million increase in the sale of property and a $1.1 million increase in non-operating income, partially offset by a $1.9 million increase in other deductions. Other income (expense), net decreased $3.8 million in 2011 compared to 2010 primarily due to a decrease in amounts collected from customers for contributions in aid of construction.

Income Taxes

Income taxes increased $8.2 million, or 19.4%, in 2012 compared to 2011 primarily resulting from higher pre-tax earnings and an increase due to lower State of Mississippi manufacturing investment tax credits, partially offset by an increase in AFUDC equity, which is non-taxable, and a decrease in unrecognized tax benefits. Income taxes decreased $4.1 million, or 8.8%, in 2011 compared to 2010 primarily due to an increase in AFUDC equity, which is non-taxable, and an increase in a State of Mississippi manufacturing investment tax credit, partially offset by increased pre-tax income.

Effects of Inflation

The Company is subject to rate regulation that is generally based on the recovery of historical and projected costs. The effects of inflation can create an economic loss since the recovery of costs could be in dollars that have less purchasing power. Any adverse effect of inflation on the Company's results of operations has not been substantial in recent years.

FUTURE EARNINGS POTENTIAL

General

The Company operates as a vertically integrated utility providing electricity to retail customers within its traditional service area located in southeast Mississippi and to wholesale customers in the Southeast. Prices for electricity provided by the Company to retail customers are set by the Mississippi PSC under cost-based regulatory principles. Retail rates and earnings are reviewed and may be adjusted periodically within certain limitations. Prices for wholesale electricity sales, interconnecting transmission lines, and the exchange of electric power are regulated by the FERC. See "FERC Matters" herein, ACCOUNTING POLICIES – "Application of Critical Accounting Policies and Estimates – Electric Utility Regulation" herein, and Note 3 to the financial statements under "Retail Regulatory Matters" for additional information about regulatory matters.

The results of operations for the past three years are not necessarily indicative of future earnings potential. The level of the Company's future earnings depends on numerous factors that affect the opportunities, challenges, and risks of the Company's business of selling electricity. These factors include the Company's ability to maintain a constructive regulatory environment that continues to allow for the timely recovery of prudently-incurred costs during a time of increasing costs and the successful completion of ongoing construction projects, including construction of generating facilities. Future earnings in the near term will depend, in part, upon maintaining energy sales which is subject to a number of factors. These factors include weather, competition, new energy contracts with neighboring utilities, energy conservation practiced by customers, the price of electricity, the price elasticity of demand, and the rate of economic growth or decline in the Company's service territory. Changes in

economic conditions impact sales for the Company, and the pace of the economic recovery remains uncertain. The timing and extent of the economic recovery will impact growth and may impact future earnings.

Environmental Matters

Compliance costs related to federal and state environmental statutes and regulations could affect earnings if such costs cannot continue to be fully recovered in rates on a timely basis. Environmental compliance spending over the next several years may differ materially from the amounts estimated. The timing, specific requirements, and estimated costs could change as environmental statutes and regulations are adopted or modified. Further, higher costs that are recovered through regulated rates could contribute to reduced demand for electricity, which could negatively affect results of operations, cash flows, and financial condition. See Note 3 to the financial statements under "Environmental Matters" for additional information.

New Source Review Actions

In 1999, the Environmental Protection Agency (EPA) brought a civil action in the U.S. District Court for the Northern District of Georgia against certain Southern Company subsidiaries, including Alabama Power Company (Alabama Power) and Georgia Power Company (Georgia Power), alleging that these subsidiaries had violated the New Source Review (NSR) provisions of the Clean Air Act and related state laws at certain coal-fired generating facilities. The EPA alleged NSR violations at five coal-fired generating facilities operated by Alabama Power, including a unit co-owned by the Company, and three coal-fired generating facilities operated by Georgia Power. The civil action sought penalties and injunctive relief, including an order requiring installation of the best available control technology at the affected units. These actions were filed concurrently with the issuance of notices of violation to the Company with respect to the Company's Plant Watson. The case against Georgia Power was administratively closed in 2001 and has not been reopened. After Alabama Power was dismissed from the original action, the EPA filed a separate action in 2001 against Alabama Power (including claims related to the unit co-owned by the Company) in the U.S. District Court for the Northern District of Alabama.

In 2006, the U.S. District Court for the Northern District of Alabama entered a consent decree, resolving claims relating to the alleged NSR violations at Plant Miller. In 2010, the EPA dismissed five of its eight remaining claims against Alabama Power, leaving only three claims, including one relating to the unit co-owned by the Company. In March 2011, the U.S. District Court for the Northern District of Alabama granted Alabama Power summary judgment on all remaining claims and dismissed the case with prejudice. That judgment is on appeal to the U.S. Court of Appeals for the Eleventh Circuit. On February 23, 2012, the EPA filed a motion in the U.S. District Court for the Northern District of Alabama seeking vacatur of the judgment and recusal of the judge in the case involving Alabama Power.

The Company believes it complied with applicable laws and regulations in effect at the time the work in question took place. The Clean Air Act authorizes maximum civil penalties of $25,000 to $37,500 per day, per violation, depending on the date of the alleged violation. An adverse outcome could require substantial capital expenditures that cannot be determined at this time and could possibly require payment of substantial penalties. Such expenditures could affect future results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates. The ultimate outcome of this matter cannot be determined at this time.

Climate Change Litigation

Kivalina Case

In 2008, the Native Village of Kivalina and the City of Kivalina filed a lawsuit in the U.S. District Court for the Northern District of California against several electric utilities (including Southern Company), several oil companies, and a coal company. The plaintiffs allege that the village is being destroyed by erosion allegedly caused by global warming that the plaintiffs attribute to emissions of greenhouse gases by the defendants. The plaintiffs assert claims for public and private nuisance and contend that some of the defendants (including Southern Company) acted in concert and are therefore jointly and severally liable for the plaintiffs' damages. The suit seeks damages for lost property values and for the cost of relocating the village, which is alleged to be $95 million to $400 million. In 2009, the U.S. District Court for the Northern District of California granted the defendants' motions to dismiss the case. On September 21, 2012, the U.S. Court of Appeals for the Ninth Circuit upheld the U.S. District Court for the Northern District of California's dismissal of the case. On November 27, 2012, the U.S. Court of Appeals for the Ninth Circuit denied the plaintiffs' request for review of the decision. On February 25, 2013, the plaintiffs filed a petition for writ of certiorari with the U.S. Supreme Court. Southern Company believes that these claims are without merit. The ultimate outcome of this matter cannot be determined at this time.

Environmental Statutes and Regulations

General

The Company's operations are subject to extensive regulation by state and federal environmental agencies under a variety of statutes and regulations governing environmental media, including air, water, and land resources. Applicable statutes include the Clean Air Act; the Clean Water Act; the Comprehensive Environmental Response, Compensation, and Liability Act; the Resource Conservation and Recovery Act; the Toxic Substances Control Act; the Emergency Planning & Community Right-to-Know Act; the Endangered Species Act; and related federal and state regulations. Compliance with these environmental requirements involves significant capital and operating costs, a major portion of which is expected to be recovered through existing ratemaking provisions. Through 2012, the Company had invested approximately $300 million in environmental capital retrofit projects to comply with these requirements, with annual totals of approximately $52 million, $23 million, and $2 million for 2012, 2011, and 2010, respectively. The Company expects that base level capital expenditures to comply with existing statutes and regulations, including capital expenditures and compliance costs associated with the EPA's final Mercury and Air Toxics Standards (MATS) rule, will be a total of approximately $419 million from 2013 through 2015, with annual totals of approximately $129 million, $174 million, and $116 million for 2013, 2014, and 2015, respectively.

The Company continues to monitor the development of the EPA's proposed water and coal combustion byproducts rules and to evaluate compliance options. See FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" herein for the Company's anticipated incremental compliance costs related to the proposed water and coal combustion byproducts rules for 2013 through 2015. The ultimate capital expenditures and compliance costs with respect to these proposed rules, including additional expenditures required after 2015, will be dependent on the requirements of the final rules and regulations adopted by the EPA and the outcome of any legal challenges to these rules. See "Water Quality" and "Coal Combustion Byproducts" herein for additional information.

The Company's ultimate environmental compliance strategy, including potential unit retirement and replacement decisions, and future environmental capital expenditures will be affected by the final requirements of new or revised environmental regulations and regulations relating to global climate change that are promulgated, including the proposed environmental regulations described below; the outcome of any legal challenges to the environmental rules; the cost, availability, and existing inventory of emissions allowances; and the Company's fuel mix. Compliance costs may arise from existing unit retirements, installation of additional environmental controls, and adding or changing fuel sources for certain existing units. The ultimate outcome of these matters cannot be determined at this time.

Compliance with any new federal or state legislation or regulations relating to air quality, water, coal combustion byproducts, global climate change, or other environmental and health concerns could significantly affect the Company. Although new or revised environmental legislation or regulations could affect many areas of the Company's operations, the full impact of any such changes cannot be determined at this time. Additionally, many of the Company's commercial and industrial customers may also be affected by existing and future environmental requirements, which for some may have the potential to ultimately affect their demand for electricity.

Air Quality

Compliance with the Clean Air Act and resulting regulations has been and will continue to be a significant focus for the Company. Since 1990, the Company has spent approximately $183 million in reducing and monitoring emissions pursuant to the Clean Air Act. Additional controls are currently planned or under consideration to further reduce air emissions, maintain compliance with existing regulations, and meet new requirements.

Final revisions to the National Ambient Air Quality Standard for sulfur dioxide (SO_2), including the establishment of a new one-hour standard, became effective in 2010. The EPA plans to issue area designations under this new standard in June 2013, and areas within the Company's service territory could ultimately be designated as nonattainment. Implementation of the revised SO_2 standard could require additional reductions in SO_2 emissions and increased compliance and operational costs.

Revisions to the National Ambient Air Quality Standard for nitrogen dioxide (NO_2), which established a new one-hour standard, became effective in 2010. On February 29, 2012, the new NO_2 standard became effective. The EPA designated the entire country as "unclassifiable/attainment" under the new standard, with no nonattainment areas designated. However, the new NO_2 standard could result in significant additional compliance and operational costs for units that require new source permitting.

The Company's service territory is subject to the requirements of the Clean Air Interstate Rule (CAIR), which calls for phased reductions in SO_2 and nitrogen oxide emissions from power plants in 28 eastern states. In 2008, the U.S. Court of Appeals for the District of Columbia Circuit issued decisions invalidating CAIR, but left CAIR compliance requirements in place while the EPA developed a new rule. In August 2011, the EPA adopted the Cross State Air Pollution Rule (CSAPR) to replace CAIR effective January 1, 2012. However, in December 2011, the U.S. Court of Appeals for the District of Columbia Circuit stayed the rule and, on August 21, 2012, vacated CSAPR in its entirety and directed the EPA to continue to administer CAIR pending the EPA's development of a valid replacement. On January 24, 2013, the U.S. Court of Appeals for the District of Columbia Circuit denied requests by the EPA and other parties for rehearing.

The EPA finalized the Clean Air Visibility Rule (CAVR) in 2005, with a goal of restoring natural visibility conditions in certain areas (primarily national parks and wilderness areas) by 2064. The rule involves the application of best available retrofit technology (BART) to certain sources built between 1962 and 1977 and any additional emissions reductions necessary for each designated area to achieve reasonable progress toward the natural visibility conditions goal by 2018 and for each 10-year period thereafter. In 2005, the EPA determined that compliance with CAIR satisfies BART obligations under CAVR, but on June 7, 2012, the EPA issued a final rule replacing CAIR with CSAPR as an alternative means of satisfying BART obligations. The vacatur of CSAPR creates additional uncertainty with respect to whether additional controls may be required for CAVR and BART compliance.

On February 16, 2012, the EPA published the final MATS rule, which imposes stringent emissions limits for acid gases, mercury, and particulate matter on coal- and oil-fired electric utility steam generating units. Compliance for existing sources is required by April 16, 2015, unless a one-year compliance extension is granted by the state or local air permitting agency. The Company has received this one-year compliance extension for Plant Daniel to April 16, 2016.

Numerous petitions for administrative reconsideration of the MATS rule, including a petition by the Company, have been filed with the EPA. On November 30, 2012, the EPA proposed a reconsideration of certain new source and startup/shutdown issues. The EPA plans to complete its reconsideration rulemaking by March 2013. Challenges to the final rule have also been filed in the U.S. District Court for the District of Columbia by numerous states, environmental organizations, industry groups, and others.

On August 29, 2012, the EPA published proposed revisions to the New Source Performance Standard (NSPS) for Stationary Combustion Turbines (CTs). If finalized as proposed, the revisions would apply the NSPS to all new, reconstructed, and modified CTs (including CTs at combined cycle units), during all periods of operation, including startup and shutdown, and alter the criteria for determining when an existing CT has been reconstructed.

On February 12, 2013, the EPA proposed a rule that would require certain states to revise the provisions of their State Implementation Plans (SIPs) relating to the regulation of excess emissions at industrial facilities, including fossil fuel-fired generating facilities, during periods of startup, shut-down, or malfunction (SSM). The EPA proposes a determination that the SSM provisions in the SIPs for 36 states (including Alabama and Mississippi) do not meet the requirements of the Clean Air Act and must be revised within 18 months of the date on which the EPA publishes the final rule. If finalized as proposed, this new requirement could result in significant additional compliance and operational costs.

The Company has developed and continually updates a comprehensive environmental compliance strategy to assess compliance obligations associated with the existing and new environmental requirements discussed above. The impacts of the eight-hour ozone, SO_2 and NO_2 standards, CAIR and any future replacement rule, CAVR, the MATS rule, the NSPS for CTs, and the SSM rule on the Company cannot be determined at this time and will depend on the specific provisions of recently finalized and future rules, the resolution of pending and future legal challenges, and the development and implementation of rules at the state level. These regulations could result in significant additional compliance costs that could affect future unit retirement and replacement decisions and results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates. Further, higher costs that are recovered through regulated rates could contribute to reduced demand for electricity, which could negatively impact results of operations, cash flows, and financial condition.

See Note 3 to the financial statements under "Retail Regulatory Matters – Environmental Compliance Overview Plan" for additional information.

Water Quality

In April 2011, the EPA published a proposed rule that establishes standards for reducing effects on fish and other aquatic life caused by cooling water intake structures at existing power plants and manufacturing facilities. The rule also addresses cooling water intake structures for new units at existing facilities. Compliance with the proposed rule could require changes to existing cooling water intake structures at certain of the Company's generating facilities, and new generating units constructed at existing plants would be required to install closed cycle cooling towers. The EPA has entered into an amended settlement agreement to

extend the deadline for issuing a final rule until June 27, 2013. If finalized as proposed, some of the Company's facilities may be subject to significant additional capital expenditures and compliance costs that could affect future unit retirement and replacement decisions. Also, results of operations, cash flows, and financial condition could be significantly impacted if such costs are not recovered through regulated rates. The ultimate outcome of this rulemaking will depend on the final rule and the outcome of any legal challenges and cannot be determined at this time.

The EPA has announced its determination that revision of the current effluent guidelines for steam electric power plants is warranted and has stated that it intends to propose such revisions by April 2013 and finalize the revisions by May 2014. New advanced wastewater treatment requirements are expected and may result in the installation of additional controls on certain of the Company's facilities, which could result in significant additional capital expenditures and compliance costs that could affect future unit retirement and replacement decisions. The impact of the revised guidelines will depend on the specific technology requirements of the final rule and, therefore, cannot be determined at this time. See FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" for additional information regarding estimated compliance costs for 2013 through 2015.

Coal Combustion Byproducts

The Company currently operates two electric generating plants with on-site coal combustion byproducts storage facilities. In addition to on-site storage, the Company also sells a portion of its coal combustion byproducts to third parties for beneficial reuse. Historically, individual states have regulated coal combustion byproducts and the States of Mississippi and Alabama each has its own regulatory parameters. The Company has a routine and robust inspection program in place to ensure the integrity of its coal ash surface impoundments and compliance with applicable regulations.

The EPA continues to evaluate the regulatory program for coal combustion byproducts, including coal ash and gypsum, under federal solid and hazardous waste laws. In 2010, the EPA published a proposed rule that requested comments on two potential regulatory options for the management and disposal of coal combustion byproducts: regulation as a solid waste or regulation as if the materials technically constituted a hazardous waste. Adoption of either option could require closure of, or significant change to, existing storage facilities and construction of lined landfills, as well as additional waste management and groundwater monitoring requirements. Under both options, the EPA proposes to exempt the beneficial reuse of coal combustion byproducts from regulation; however, a hazardous or other designation indicative of heightened risk could limit or eliminate beneficial reuse options. Environmental groups and other parties have filed lawsuits in the U.S. District Court for the District of Columbia seeking to require the EPA to complete its rulemaking process and issue final regulations pertaining to the regulation of coal combustion byproducts.

While the ultimate outcome of this matter cannot be determined at this time and will depend on the final form of any rules adopted and the outcome of any legal challenges, additional regulation of coal combustion byproducts could have a material impact on the generation, management, beneficial use, and disposal of such byproducts. Any material changes are likely to result in substantial additional compliance, operational, and capital costs that could affect future unit retirement and replacement decisions. Moreover, the Company could incur additional material asset retirement obligations with respect to closing existing storage facilities. The Company's results of operations, cash flows, and financial condition could be significantly impacted if such costs are not recovered through regulated rates. Further, higher costs that are recovered through regulated rates could contribute to reduced demand for electricity, which could negatively impact results of operations, cash flows, and financial condition. See FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" for additional information regarding estimated compliance costs for 2013 through 2015.

Environmental Remediation

The Company must comply with other environmental laws and regulations that cover the handling and disposal of waste and releases of hazardous substances. Under these various laws and regulations, the Company may also incur substantial costs to clean up properties. The Company conducts studies to determine the extent of any required cleanup and has recognized in its financial statements the costs to clean up known impacted sites. Amounts for cleanup and ongoing monitoring costs were not material for any year presented. The Company has authority from the Mississippi PSC to recover approved environmental compliance costs through its ECO clause. The Company may be liable for some or all required cleanup costs for additional sites that may require environmental remediation. See Note 3 to the financial statements under "Environmental Matters – Environmental Remediation" for additional information.

Global Climate Issues

The EPA currently regulates greenhouse gases under the Prevention of Significant Deterioration and Title V operating permit programs of the Clean Air Act. In addition, over the past several years, the U.S. Congress has considered many proposals to reduce greenhouse gas emissions, mandate renewable or clean energy, and impose energy efficiency standards. Such proposals are expected to continue to be considered by the U.S. Congress. International climate change negotiations under the United Nations Framework Convention on Climate Change are also continuing.

On April 13, 2012, the EPA published proposed regulations to establish standards of performance for greenhouse gas emissions from new fossil fuel steam electric generating units. The EPA has also announced plans to develop federal guidelines for states to establish greenhouse gas emissions performance standards for existing sources. The impact of this rulemaking will depend on the scope and specific requirements of the final rule and the outcome of any legal challenges and, therefore, cannot be determined at this time.

Although the outcome of federal, state, and international initiatives cannot be determined at this time, additional restrictions on the Company's greenhouse gas emissions or requirements relating to renewable energy or energy efficiency at the federal or state level could result in significant additional compliance costs, including capital expenditures. These costs could affect future unit retirement and replacement decisions and could result in the retirement of a significant number of coal-fired generating units. Also, additional compliance costs and costs related to unit retirements could affect results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates. Further, higher costs that are recovered through regulated rates could contribute to reduced demand for electricity, which could negatively impact results of operations, cash flows, and financial condition.

The EPA's greenhouse gas reporting rule requires annual reporting of carbon dioxide equivalent emissions in metric tons for a company's operational control of facilities. Based on ownership or financial control of facilities, the Company reported 2011 greenhouse gas emissions of approximately 9 million metric tons of carbon dioxide equivalent. The preliminary estimate of the Company's 2012 greenhouse gas emissions on the same basis is approximately 7 million metric tons of carbon dioxide equivalent. The level of greenhouse gas emissions from year to year will depend on the level of generation and mix of fuel sources, which is determined primarily by demand, the unit cost of fuel consumed, and the availability of generating units.

FERC Matters

In November 2011, the Company filed a request with the FERC for an increase in wholesale base revenues of approximately $32 million under the wholesale cost-based electric tariff. In its filing with the FERC, the Company sought (i) approval to establish a regulatory asset for the portion of non-capitalizable Kemper IGCC-related costs which have been and will continue to be incurred during the construction period for the Kemper IGCC, (ii) authorization to defer as a regulatory asset, for the 10-year period ending October 2021, the difference between the revenue requirement under the purchase option of Plant Daniel Units 3 and 4 (assuming a remaining 30-year life) and the revenue requirement assuming the continuation of the operating lease regulatory treatment with the accumulated deferred balance at the end of the deferral being amortized into wholesale rates over the remaining life of Plant Daniel Units 3 and 4, and (iii) authority to defer in a regulatory asset costs related to the retirement or partial retirement of generating units as a result of environmental compliance rules.

On March 9, 2012, the Company entered into a settlement agreement with its wholesale customers with respect to the Company's request for revised rates under the wholesale cost-based electric tariff. The settlement agreement provides that base rates under the cost-based electric tariff will increase by approximately $22.6 million over a 12-month period with revised rates effective April 1, 2012. A significant portion of the difference between the requested base rate increase and the agreed upon rate increase is due to a change in the CWIP recovery on the Kemper IGCC. Under the settlement agreement, a portion of CWIP will continue to accrue AFUDC. The tariff customers specifically agreed to the same regulatory treatment for tariff ratemaking as the treatment approved for retail ratemaking by the Mississippi PSC with respect to (i) the accounting for Kemper IGCC-related costs that cannot be capitalized, (ii) the accounting for the lease termination and purchase of Plant Daniel Units 3 and 4, and (iii) the establishment of a regulatory asset for certain potential plant retirement costs.

On March 28, 2012, the FERC approved a motion to place interim rates into effect beginning in May 2012. On September 27, 2012, the Company, with its wholesale customers, filed a final settlement agreement with the FERC. On November 5, 2012, the settlement judge certified the settlement agreement to the FERC with the recommendation that it be approved. The FERC has not yet approved the settlement agreement. The ultimate outcome of this matter cannot be determined at this time.

PSC Matters

General

On August 7, 2012, the Mississippi PSC issued an order for the purpose of investigating and reviewing for informational purposes only the ROE formulas used by the Company and all other regulated electric utilities in Mississippi. The ultimate outcome of this matter cannot be determined at this time.

Performance Evaluation Plan

In the 2004 order establishing the Company's forward-looking PEP, the Mississippi PSC ordered that the Mississippi Public Utilities Staff (MPUS) and the Company review the operations of the PEP in 2007. By mutual agreement, this review was deferred until 2008 and continued into 2009. In 2009, concurrent with this review, the annual PEP evaluation filing for 2009 was suspended and the MPUS and the Company filed a joint report with the Mississippi PSC proposing several changes to the PEP. The Mississippi PSC approved the revised PEP in 2009, which resulted in a lower performance incentive under the PEP and therefore smaller and/or less frequent rate changes in the future. Later that year, the Company resumed annual evaluations and filed its annual PEP filing for 2010 under the revised PEP, which resulted in a lower allowed return on investment but no rate change.

In 2010, the Company filed its annual PEP filing for 2011 under the revised PEP, which indicated a rate increase of 1.936%, or $16.1 million, annually. In January 2011, the MPUS contested the filing. In June 2011, the Mississippi PSC issued an order approving a joint stipulation between the MPUS and the Company resulting in no change in rates.

In November 2011, the Company filed its annual PEP filing for 2012, which indicated a rate increase of 1.893%, or $17.4 million, annually. On January 10, 2012, the MPUS contested the filing.

In March 2011, the Company submitted its annual PEP lookback filing for 2010, which recommended no surcharge or refund. In May 2011, the Company received a letter from the MPUS disputing certain items in the 2010 PEP lookback filing. On April 2, 2012, the Company filed a motion to suspend the PEP lookback filing for 2011. Unresolved matters related to certain costs included in the 2010 PEP lookback filing also impact the 2011 PEP lookback filing, making it impractical to determine the Company's actual retail return on investment for 2011 for purposes of the 2011 PEP lookback filing. An order granting the suspension of the 2011 PEP lookback was signed by the Mississippi PSC on May 8, 2012. On or before March 15, 2013, the Company will submit its annual PEP lookback filing for 2012. While the Company does not expect the resolution of these unresolved matters to have a material impact on its financial statements, the ultimate outcome of these matters cannot be determined at this time.

On January 18, 2013, the Company filed its annual PEP filing for 2013, which indicated a rate increase of 1.990%, or $15.8 million, annually.

The ultimate outcome of these matters cannot be determined at this time.

Environmental Compliance Overview Plan

In November 2011, the Company filed a request to establish a regulatory asset to defer certain plant retirement costs if such costs are incurred. This request was made to minimize the potential rate impact to customers arising from pending and final environmental regulations which may require the premature retirement of some generating units. These environmental rules and regulations are continuously being monitored by the Company and all options are being evaluated. In December 2011, an order was issued by the Mississippi PSC authorizing the Company to defer all plant retirement related costs resulting from compliance with environmental regulations as a regulatory asset for future recovery.

On February 14, 2012, the Company submitted its 2012 ECO Plan filing, which proposed a 0.3% increase in annual revenues for the Company. In compliance with the CPCN to construct a flue gas desulfurization system (scrubber) on Plant Daniel Units 1 and 2, the Company revised the 2012 ECO Plan filing to exclude scrubber expenditures from rate base, which resulted in a 0.16% decrease in annual revenues. On June 22, 2012, the 2012 ECO Plan filing, including the proposed rate decrease, was approved by the Mississippi PSC, effective on June 29, 2012.

On April 3, 2012, the Mississippi PSC approved the Company's request for a CPCN to construct a scrubber on Plant Daniel Units 1 and 2. On May 3, 2012, the Sierra Club filed a notice of appeal of the order with the Chancery Court of Harrison County, Mississippi (Chancery Court). These units are jointly owned by the Company and Gulf Power, with 50% ownership each. The estimated total cost of the project is approximately $660 million, with the Company's portion being $330 million, excluding AFUDC. The project is scheduled for completion in December 2015. The Company's portion of the cost is expected to be

recovered through the ECO Plan. As of December 31, 2012, total project expenditures were $146.6 million, with the Company's portion being $73.3 million.

On February 12, 2013, the Company submitted its 2013 ECO Plan filing, which proposed no change in rates.

The ultimate outcome of these matters cannot be determined at this time.

Certificated New Plant

See "Integrated Coal Gasification Combined Cycle" for information on certificated new plant and the Company's cost recovery plans.

Fuel Cost Recovery

The Company establishes, annually, a retail fuel cost recovery factor that is approved by the Mississippi PSC. On January 18, 2013, in compliance with the Company's filing requirement, the Company requested an annual adjustment of the retail fuel cost recovery factor in an amount equal to a decrease of 4.7% of total 2012 retail revenue. At December 31, 2012, the amount of over recovered retail fuel costs included in the balance sheets was $56.6 million compared to $42.4 million at December 31, 2011. The Company also has a wholesale Municipal and Rural Associations (MRA) and a Market Based (MB) fuel cost recovery factor. Effective January 1, 2013, the wholesale MRA fuel rate decreased resulting in an annual decrease in an amount equal to 3.3% of total 2012 MRA revenue. Effective February 1, 2013, the wholesale MB fuel rate decreased, resulting in an annual decrease in an amount equal to 5.5% of total 2012 MB revenue. At December 31, 2012, the amount of over recovered wholesale MRA and MB fuel costs included in the balance sheets was $19.0 million and $2.1 million compared to $14.3 million and $2.2 million, respectively, at December 31, 2011. In addition, at December 31, 2012, the amount of over recovered MRA emissions allowance cost included in the balance sheets was $0.4 million compared to $1.7 million at December 31, 2011. The Company's operating revenues are adjusted for differences in actual recoverable fuel cost and amounts billed in accordance with the currently approved cost recovery rate. Accordingly, changes in the billing factor have no significant effect on the Company's revenues or net income, but will affect annual cash flow.

In March 2011, a portion of the Company's territorial wholesale loads that was formerly served under the MB tariff terminated service. Beginning in April 2011, a new power purchase agreement (PPA) went into effect to cover these MB customers as non-territorial load. In June 2011, the Company and SMEPA reached an agreement to allocate $3.7 million of the over recovered fuel balance at March 31, 2011 to the PPA. This amount was subsequently refunded to SMEPA in June 2011. See "Other Matters" herein for additional information.

The Mississippi PSC engaged an independent professional audit firm to conduct an audit of the Company's fuel-related expenditures included in the retail fuel adjustment clause and energy cost management clause (ECM). The 2012 audit of fuel-related expenditures began in the second quarter 2012 and was completed in the fourth quarter 2012 with no audit findings.

Storm Damage Cost Recovery

In August 2012, Hurricane Isaac hit the Gulf Coast of the United States and caused damage within the Company's service area. The estimated total storm restoration costs relating to Hurricane Isaac through December 31, 2012 were $10.5 million. The Company maintains a reserve to cover the cost of damage from major storms to its transmission and distribution facilities and generally the cost of uninsured damage to its generation facilities and other property. At December 31, 2012, the balance in the storm reserve was $58.8 million.

Income Tax Matters

Bonus Depreciation

In 2010, the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010 (Tax Relief Act) was signed into law. Major tax incentives in the Tax Relief Act include 100% bonus depreciation for property placed in service after September 8, 2010 and through 2011 (and for certain long-term production-period projects placed in service in 2012) and 50% bonus depreciation for property placed in service in 2012 (and for certain long-term production-period projects to be placed in service in 2013), which will have a positive impact on the future cash flows of the Company through 2013.

On January 2, 2013, the American Taxpayer Relief Act of 2012 (ATRA) was signed into law. The ATRA retroactively extended several tax credits through 2013 and extended 50% bonus depreciation for property to be placed in service in 2013 (and for certain long-term production-period projects to be placed in service in 2014), which is expected to apply to the Kemper IGCC scheduled to be placed in service in May 2014.

Due to the significant amount of estimated bonus depreciation for 2013, the utilization of a portion of the Company's tax credits has been delayed. See "Integrated Coal Gasification Combined Cycle – Tax Incentives" for additional information.

Integrated Coal Gasification Combined Cycle

General

The Company is constructing the Kemper IGCC which will utilize an IGCC technology with an output capacity of 582 MWs. The Kemper IGCC will use as fuel locally mined lignite (an abundant, lower heating value coal) from a mine owned by the Company and situated adjacent to the Kemper IGCC. In connection with the Kemper IGCC, the Company also plans to construct and operate approximately 61 miles of carbon dioxide (CO_2) pipeline infrastructure. The Kemper IGCC is scheduled to be placed in-service in May 2014.

In 2010, the Mississippi PSC issued a CPCN authorizing the acquisition, construction, and operation of the Kemper IGCC (2010 MPSC Order). The Sierra Club filed an appeal of the Mississippi PSC's issuance of the CPCN and, on March 15, 2012, the Mississippi Supreme Court reversed the decision of the Chancery Court of Harrison County Mississippi (Chancery Court) upholding the 2010 MPSC Order and remanded the matter to the Mississippi PSC. The Mississippi Supreme Court concluded that the 2010 MPSC Order did not cite in sufficient detail substantial evidence upon which the Mississippi Supreme Court could determine the basis for the findings of the Mississippi PSC granting the CPCN. On March 30, 2012, the Mississippi PSC issued a temporary authorization which allowed the Company to continue construction and, on April 24, 2012, issued a detailed order (2012 MPSC Order) confirming the CPCN for the Kemper IGCC. On April 26, 2012, the Sierra Club appealed the 2012 MPSC Order to the Chancery Court. On December 17, 2012, the Chancery Court affirmed the 2012 MPSC Order which confirmed the issuance of the CPCN for the Kemper IGCC. On January 8, 2013, the Sierra Club filed an appeal of the Chancery Court's ruling with the Mississippi Supreme Court.

The certificated cost estimate of the Kemper IGCC included in the 2012 MPSC Order was $2.4 billion, net of $245.3 million of grants awarded to the project by the United States Department of Energy (DOE) under the Clean Coal Power Initiative Round 2 (CCPI2) and excluding the cost of the lignite mine and equipment, the cost of the CO_2 pipeline facilities, and financing costs related to the Kemper IGCC. The 2012 MPSC Order approved a construction cost cap of up to $2.88 billion, with recovery of prudently-incurred costs subject to approval by the Mississippi PSC. Exemptions from the cost cap included in the 2012 MPSC Order included the cost of the lignite mine and equipment, the cost of the CO_2 pipeline facilities, financing costs, and certain general exceptions, including change of law, force majeure, and beneficial capital (which exists when the Company demonstrates that the purpose and effect of the construction cost increase is to produce efficiencies that will result in a neutral or favorable effect on the ratepayers, relative to the original proposal for the CPCN).

The Company's current cost estimate for the Kemper IGCC (net of the $245.3 million CCPI2 grant, and excluding the cost of the lignite mine and equipment, the cost of the CO_2 pipeline facilities, financing costs, and certain general exceptions as contemplated in the 2012 MPSC Order and the Settlement Agreement that must be specifically approved by the Mississippi PSC) is approximately $2.88 billion. The Mississippi PSC and the MPUS have engaged their independent monitors to assess the current cost estimates and schedule projections for the Kemper IGCC. These consultants have issued reports with their own opinions as to the likelihood that costs for the Kemper IGCC will remain at or under the $2.88 billion cost cap and as to the expected in-service date. While the Company continues to believe its cost estimate and schedule projection remain appropriate based on the current status of the project, it is possible that the Company could experience further cost increases and/or schedule delays with respect to the Kemper IGCC. Certain factors have caused and may continue to cause the costs for the Kemper IGCC to increase and/or schedule delays to occur including, but not limited to, costs and productivity of labor, adverse weather conditions, shortages and inconsistent quality of equipment, materials, and labor, contractor or supplier delay or non-performance under construction or other agreements, and unforeseen engineering problems. To the extent it becomes probable that costs beyond any permitted exceptions to the cost cap will exceed $2.88 billion or it becomes probable that the Mississippi PSC will disallow a portion of the costs relating to the Kemper IGCC, including certain general exceptions as contemplated in the 2012 MPSC Order and the Settlement Agreement, charges to expense may occur and these charges could be material. See "Cost Recovery Plans" below for additional information relating to the Settlement Agreement that defines the process for resolving matters regarding cost recovery related to the Kemper IGCC.

As of December 31, 2012, the Company had spent a total of $2.51 billion on the Kemper IGCC, including the cost of the lignite mine and equipment, the cost of the CO_2 pipeline facilities, and other deferred costs. Of this total, $2.47 billion was included in CWIP (which is net of $245.3 million of CCPI2 grant funds), $34.9 million was recorded in other regulatory assets, $3.8 million was recorded in other deferred charges and assets, and $1.0 million was previously expensed. Consistent with the treatment of non-capital costs incurred during the pre-construction period, the Mississippi PSC granted the Company the authority to defer all non-capital Kemper IGCC-related costs to a regulatory asset during the construction period. This includes deferred costs

associated with the generation resource planning, evaluation, and screening activities. The amortization period for the regulatory asset will be determined by the Mississippi PSC at a later date.

In addition, the Company is authorized to accrue carrying costs on the unamortized balance of such regulatory assets at a rate and in a manner to be determined by the Mississippi PSC in future cost recovery mechanism proceedings.

The 2012 MPSC Order established periodic prudence reviews during the annual CWIP review process. Of the total costs of $51 million incurred through March 2009, $46 million has been reviewed and deemed prudent by the Mississippi PSC. Due to the decision of the Mississippi PSC to deny the CNP-A rate filing and a 2012 rate request related to the Kemper IGCC described below, prudence reviews for the construction costs of the Kemper IGCC incurred after March 2009 have not been made. The Settlement Agreement provides for completion of all prudence reviews within six months of the date the Kemper IGCC is placed in service. See "Cost Recovery Plans" herein for additional information.

The ultimate outcome of these matters, including the determinations of prudency and the specific manner of recovery of prudently-incurred costs relating to the Kemper IGCC, is subject to further regulatory actions and cannot be determined at this time.

Cost Recovery Plans

The 2012 MPSC Order included provisions relating to both the Company's recovery of financing costs during the course of construction of the Kemper IGCC and the Company's recovery of costs following the date the Kemper IGCC is placed in service. In the 2012 MPSC Order, the Mississippi PSC approved financing cost recovery on CWIP balances not to exceed the $2.4 billion certificated cost estimate for the Kemper IGCC. The 2012 MPSC Order provided for the accrual of AFUDC in 2010 and 2011 and for the current recovery of financing costs on 100% of CWIP in 2012, 2013, and through May 1, 2014 (provided that the amount of financing cost recovery allowed is to be reduced by the amount of certain state and federal government construction cost incentives received by the Company and must be justified by a showing that such recovery will benefit customers over the life of the Kemper IGCC). With respect to recovery of costs following the in-service date of the Kemper IGCC, the 2012 MPSC Order provided for the establishment of operational cost and revenue parameters based upon assumptions in the Company's petition for the CPCN.

On June 1, 2012, the MPUS signed a joint stipulation with the Company to establish a proposed rate schedule detailing CNP-A and, on June 14, 2012, the Company submitted to the Mississippi PSC a filing to establish the new CNP-A rate schedule and a stipulated rate increase based upon the revenue request of between $55.3 million and $58.6 million to recover financing costs over the remainder of 2012. On June 22, 2012, the Mississippi PSC denied the proposed CNP-A rate schedule and the 2012 rate recovery filings submitted by the Company, pending a final ruling from the Mississippi Supreme Court regarding the Sierra Club's appeal of the Mississippi PSC's issuance of the CPCN for the Kemper IGCC.

On July 9, 2012, the Company appealed the Mississippi PSC's June 22, 2012 decision to the Mississippi Supreme Court and requested interim rates under bond of $55.3 million. On July 31, 2012, the Mississippi Supreme Court denied the Company's request for interim rates under bond until the Mississippi Supreme Court decides the Company's appeal of the Mississippi PSC's June 22, 2012 decision.

On January 24, 2013, the Company and the Mississippi PSC entered into the Settlement Agreement that (1) establishes the process for resolving matters regarding cost recovery related to the Kemper IGCC for the purpose of mitigating risks to the Company and its customers and expediting the regulatory process associated with future rate filings required under the Settlement Agreement and (2) resolves the Company's CNP-A rate appeal before the Mississippi Supreme Court.

On February 12, 2013, the Mississippi Supreme Court granted the Company and the Mississippi PSC's joint filing for dismissal of the Company's appeal of the Mississippi PSC's June 22, 2012 decision.

Under the terms of the Settlement Agreement, the Company and the Mississippi PSC will follow certain agreed-upon regulatory procedures and schedules for resolving the cost recovery matters related to the Kemper IGCC. These procedures and schedules include the following: (1) the Company's filing within 30 days of the Settlement Agreement of a new request to increase rates in 2013 in an amount not to exceed a $172 million annual revenue requirement, based upon projected investment as of December 31, 2013, to be recorded to a regulatory liability to be used to mitigate rate impacts when the Kemper IGCC is placed in service (which filing for $172 million was made on January 25, 2013); (2) the Mississippi PSC's decision on that matter within 50 days of the Company's request; (3) the Company's collaboration with the MPUS to file with the Mississippi PSC within three months of the Settlement Agreement a rate recovery plan for the Kemper IGCC for the first seven years of its operation, along with a proposed revenue requirement under such plan for 2014 through 2020 (which filing was made on February 26, 2013 as described below); (4) the Mississippi PSC's decision on the rate recovery plan within four months of that filing; (5) the Company's agreement to limit the portion of prudently-incurred Kemper IGCC costs to be included in rate base to the $2.4 billion certificated

cost estimate, plus costs related to the lignite mine and CO_2 pipeline as well as any other costs permitted or determined to be excluded from the cost cap, provided that this limitation will not prevent the Company from securing alternate financing to recover any prudently-incurred Kemper IGCC costs, including financing costs and plant costs above the $2.4 billion certificated cost estimate, not otherwise recovered in any Mississippi PSC rate proceeding contemplated by the Settlement Agreement; and (6) the Mississippi PSC's completion of its prudence review of the Kemper IGCC costs incurred through 2012 within six months of the Settlement Agreement, an additional prudence review upon considering the seven-year rate plan for costs incurred through the most recent reporting period, and a final prudence review of the remaining project costs within six months of the Kemper IGCC's in-service date.

Legislation to authorize a multi-year rate plan and legislation to provide for alternate financing through securitization was passed in the Mississippi legislature and was signed by the Governor on February 26, 2013. The Company contemplates using securitization as provided in the legislation as its form of alternate financing for prudently-incurred Kemper IGCC costs, including financing costs and plant costs above the $2.4 billion certificated cost estimate, not otherwise recovered in any Mississippi PSC rate proceeding contemplated by the Settlement Agreement.

On February 26, 2013, the Company, in compliance with the Settlement Agreement, filed with the Mississippi PSC a rate recovery plan for the Kemper IGCC for 2014 through 2020, the first seven years of operation of the Kemper IGCC. The rate recovery plan proposes recovery of an annual revenue requirement of approximately $150 million of Kemper IGCC-related operational costs and rate base amounts, including plant costs equal to the $2.4 billion certificated cost estimate. Approval of the Company's request to increase rates in 2013 to mitigate the rate impacts of the Kemper IGCC filed on January 25, 2013 is integral to the rate recovery plan as the proposed filing contemplates amortization of the regulatory liability to be used to mitigate rate impacts from 2014 through 2020, based on a fixed amortization schedule that requires approval by the Mississippi PSC. Under the rate recovery plan filing, the Company proposes annual recovery to remain the same from 2014 through 2020 and while it is the intent of the Company for the actual revenue requirement to equal the proposed revenue requirement for certain items, the Company proposes that the annual differences for those items through 2020 will be deferred, subject to accrual of carrying costs, and the cumulative balance will be reviewed at the end of the term of the Settlement Agreement by the Mississippi PSC for determination of the manner of recovery. The Company proposes to secure recovery of prudently-incurred Kemper IGCC costs, including financing costs and plant costs above the $2.4 billion certificated cost estimate, not otherwise recovered in any Mississippi PSC rate proceeding contemplated by the Settlement Agreement to be provided for with alternate financing through securitization. The rate recovery necessary to recover the annual costs of securitization is proposed to be filed and begin after the Kemper IGCC is placed in service.

Under the terms of the Settlement Agreement, the Company has the right to terminate the Settlement Agreement if certain conditions, including the passage of multi-year rate plan legislation that is contemplated under the Settlement Agreement, are not met, if the Company is unable to secure alternate financing for any prudently-incurred Kemper IGCC costs not otherwise recovered in any Mississippi PSC rate proceeding contemplated by the Settlement Agreement, or if the Mississippi PSC fails to comply with the requirements of the Settlement Agreement.

The ultimate outcome of these matters, including the determinations of prudency and the specific manner of recovery of prudently-incurred costs relating to the Kemper IGCC, is subject to further regulatory actions and cannot be determined at this time.

Tax Incentives

The Internal Revenue Service (IRS) has allocated $133 million (Phase I) and $279 million (Phase II) of Internal Revenue Code Section 48A tax credits to the Company in connection with the Kemper IGCC. The Company's utilization of Phase I and Phase II credits is dependent upon meeting the IRS certification requirements, including an in-service date no later than May 11, 2014 for the Phase I credits and April 19, 2016 for the Phase II credits. In order to remain eligible for the Phase II credits, the Company plans to capture and sequester (via enhanced oil recovery) at least 65% of the CO_2 produced by the Kemper IGCC during operations in accordance with the rules for Section 48A investment tax credits. Through December 31, 2012, the Company received or accrued tax benefits totaling $361.6 million for these tax credits, which will be amortized as a reduction to depreciation and amortization over the life of the Kemper IGCC. As a result of bonus tax depreciation on certain assets placed, or to be placed, in service in 2012 and 2013, and the subsequent reduction in federal taxable income, the Company estimates that it will not be able to utilize $170.9 million of these tax credits until after 2013. IRS guidelines allow these unused tax credits to be carried forward for 20 years, expiring at the end of 2031, if not utilized before then. On October 15, 2012, the Company filed an application with the DOE for certification of the Kemper IGCC for additional tax credits under the Internal Revenue Code Section 48A (Phase III). A portion of the tax credits realized by the Company may be subject to recapture upon successful completion of SMEPA's purchase of an undivided interest in the Kemper IGCC as described below. In addition, all or a portion of

the tax credits will be subject to recapture if the Company fails to satisfy the in-service date requirements and carbon capture requirements described above. See "Income Tax Matters" herein for additional information.

The ultimate outcome of these matters cannot be determined at this time.

Lignite Mine and CO_2 Pipeline Facilities

In conjunction with the Kemper IGCC, the Company will own the lignite mine and equipment and has acquired and will continue to acquire mineral reserves located around the Kemper IGCC site in Kemper County. The mine is scheduled to be placed in-service in June 2013. The estimated capital cost of the mine is approximately $245 million, of which $163.3 million has been incurred through December 31, 2012.

In 2010, the Company executed a 40-year management fee contract with Liberty Fuels Company, LLC, a wholly-owned subsidiary of The North American Coal Corporation (Liberty Fuels), which will develop, construct, and manage the mining operations. The contract with Liberty Fuels is effective through the end of the mine reclamation. As the mining permit holder, Liberty Fuels has a legal obligation to perform mine reclamation and the Company has a contractual obligation to fund all reclamation activities. In addition to the obligation to fund the reclamation activities, the Company currently provides working capital support to Liberty Fuels through cash advances for capital purchases, payroll, and other operating expenses.

In addition, the Company will acquire, construct, and operate the CO_2 pipeline for the planned transport of captured CO_2 for use in enhanced oil recovery. The Company has entered into agreements with Denbury Onshore (Denbury), a subsidiary of Denbury Resources Inc., and Treetop Midstream Services, LLC (Treetop), an affiliate of Tellus Operating Group, LLC and a subsidiary of Tengrys, LLC, pursuant to which Denbury will purchase 70% of the CO_2 captured from the Kemper IGCC and Treetop will purchase 30% of the CO_2 captured from the Kemper IGCC. The estimated capital cost of the CO_2 pipeline facilities is approximately $132 million, of which $78.4 million has been incurred through December 31, 2012.

The ultimate outcome of these matters, including the determinations of prudency and the specific manner of recovery of prudently-incurred costs relating to the Kemper IGCC, is subject to further regulatory actions and cannot be determined at this time.

Proposed Sale of Undivided Interest to SMEPA

In 2010, the Company and SMEPA entered into an asset purchase agreement whereby SMEPA agreed to purchase a 17.5% undivided interest in the Kemper IGCC. On February 28, 2012, the Mississippi PSC approved the sale and transfer of 17.5% of the Kemper IGCC to SMEPA. On June 29, 2012, the Company and SMEPA signed an amendment to the asset purchase agreement whereby SMEPA extended its option to purchase until December 31, 2012 and reduced its purchase commitment percentage from a 17.5% to a 15% undivided interest in the Kemper IGCC, subject to approval by the Mississippi PSC. On December 31, 2012, the Company and SMEPA agreed to extend SMEPA's option to purchase through December 31, 2013.

The closing of this transaction is conditioned upon execution of a joint ownership and operating agreement, receipt of all construction permits, appropriate regulatory approvals, financing, and other conditions. On September 27, 2012, SMEPA received a conditional loan commitment from Rural Utilities Service to provide funding for SMEPA's undivided interest in the Kemper IGCC.

On March 6, 2012, the Company received a $150 million interest-bearing refundable deposit from SMEPA to be applied to the purchase. While the expectation is that the amount will be applied to the purchase price at closing, the Company would be required to refund the deposit upon the termination of the asset purchase agreement, within 60 days of a request by SMEPA for a full or partial refund, or within 15 days at SMEPA's discretion in the event that the Company is assigned a senior unsecured credit rating of BBB+ or lower by Standard and Poor's Ratings Services, a division of The McGraw Hill Companies, Inc. (S&P) or Baa1 or lower by Moody's Investors Services, Inc. (Moody's) or ceases to be rated by either of these rating agencies.

The ultimate outcome of these matters cannot be determined at this time.

Baseload Act

In the 2008 regular session of the Mississippi legislature, a bill was passed and signed by the Governor to enhance the Mississippi PSC's authority to facilitate development and construction of base load generation in the State of Mississippi (Baseload Act). The Baseload Act authorizes, but does not require, the Mississippi PSC to adopt a cost recovery mechanism that includes in retail base rates, prior to and during construction, all or a portion of the prudently-incurred pre-construction and construction costs incurred by a utility in constructing a base load electric generating plant. Prior to the passage of the Baseload Act, such costs would traditionally be recovered only after the plant was placed in service. The Baseload Act also provides for periodic prudence reviews by the Mississippi PSC and prohibits the cancellation of any such generating plant without the approval of the Mississippi PSC. In the event of cancellation of the construction of the plant without approval of the Mississippi PSC, the

Baseload Act authorizes the Mississippi PSC to make a public interest determination as to whether and to what extent the utility will be afforded rate recovery for costs incurred in connection with such cancelled generating plant. There are legal challenges to the constitutionality of the Baseload Act currently pending before the Mississippi Supreme Court. The ultimate impact of this legislation will depend on the outcome of any legal challenges and cannot be determined at this time. See "Cost Recovery Plans" herein for additional information regarding certain legislation related to the Kemper IGCC.

Other Matters

The Company is involved in various other matters being litigated and regulatory matters that could affect future earnings. In addition, the Company is subject to certain claims and legal actions arising in the ordinary course of business. The Company's business activities are subject to extensive governmental regulation related to public health and the environment, such as regulation of air emissions and water discharges. Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements, such as air quality and water standards, has increased generally throughout the U.S. In particular, personal injury, property damage, and other claims for damages alleged to have been caused by CO_2 and other emissions, coal combustion byproducts, and alleged exposure to hazardous materials, and/or requests for injunctive relief in connection with such matters, have become more frequent.

The ultimate outcome of such pending or potential litigation against the Company cannot be predicted at this time; however, for current proceedings not specifically reported herein or in Note 3 to the financial statements, management does not anticipate that the ultimate liabilities, if any, arising from such current proceedings would have a material effect on the Company's financial statements. See Note 3 to the financial statements for a discussion of various other contingencies, regulatory matters, and other matters being litigated which may affect future earnings potential.

On February 6, 2013, the Company submitted a claim under the Deepwater Horizon Economic and Property Damages Settlement Agreement associated with the oil spill that occurred in April 2010 in the Gulf of Mexico. The ultimate outcome of this matter cannot be determined at this time.

ACCOUNTING POLICIES

Application of Critical Accounting Policies and Estimates

The Company prepares its financial statements in accordance with generally accepted accounting principles (GAAP). Significant accounting policies are described in Note 1 to the financial statements. In the application of these policies, certain estimates are made that may have a material impact on the Company's results of operations and related disclosures. Different assumptions and measurements could produce estimates that are significantly different from those recorded in the financial statements. Senior management has reviewed and discussed the following critical accounting policies and estimates with the Audit Committee of Southern Company's Board of Directors.

Electric Utility Regulation

The Company is subject to retail regulation by the Mississippi PSC and wholesale regulation by the FERC. These regulatory agencies set the rates the Company is permitted to charge customers based on allowable costs. As a result, the Company applies accounting standards which require the financial statements to reflect the effects of rate regulation. Through the ratemaking process, the regulators may require the inclusion of costs or revenues in periods different than when they would be recognized by a non-regulated company. This treatment may result in the deferral of expenses and the recording of related regulatory assets based on anticipated future recovery through rates or the deferral of gains or creation of liabilities and the recording of related regulatory liabilities. The application of the accounting standards has a further effect on the Company's financial statements as a result of the estimates of allowable costs used in the ratemaking process. These estimates may differ from those actually incurred by the Company; therefore, the accounting estimates inherent in specific costs such as depreciation and pension and postretirement benefits have less of a direct impact on the Company's results of operations and financial condition than they would on a non-regulated company.

As reflected in Note 1 to the financial statements, significant regulatory assets and liabilities have been recorded. Management reviews the ultimate recoverability of these regulatory assets and any requirement to refund these regulatory liabilities based on applicable regulatory guidelines and GAAP. However, adverse legislative, judicial, or regulatory actions could materially impact the amounts of such regulatory assets and liabilities and could adversely impact the Company's financial statements.

Contingent Obligations

The Company is subject to a number of federal and state laws and regulations, as well as other factors and conditions that subject it to environmental, litigation, income tax, and other risks. See FUTURE EARNINGS POTENTIAL herein and Note 3 to the financial statements for more information regarding certain of these contingencies. The Company periodically evaluates its exposure to such risks and, in accordance with GAAP, records reserves for those matters where a non-tax-related loss is considered probable and reasonably estimable and records a tax asset or liability if it is more likely than not that a tax position will be sustained. The adequacy of reserves can be significantly affected by external events or conditions that can be unpredictable; thus, the ultimate outcome of such matters could materially affect the Company's financial statements.

Unbilled Revenues

Revenues related to the retail sale of electricity are recorded when electricity is delivered to customers. However, the determination of KWH sales to individual customers is based on the reading of their meters, which is performed on a systematic basis throughout the month. At the end of each month, amounts of electricity delivered to customers, but not yet metered and billed, are estimated. Components of the unbilled revenue estimates include total KWH territorial supply, total KWH billed, estimated total electricity lost in delivery, and customer usage. These components can fluctuate as a result of a number of factors including weather, generation patterns, power delivery volume, and other operational constraints. These factors can be unpredictable and can vary from historical trends. As a result, the overall estimate of unbilled revenues could be significantly affected, which could have a material impact on the Company's results of operations.

Pension and Other Postretirement Benefits

The Company's calculation of pension and other postretirement benefits expense is dependent on a number of assumptions. These assumptions include discount rates, healthcare cost trend rates, expected long-term return on plan assets, mortality rates, expected salary and wage increases, and other factors. Components of pension and other postretirement benefits expense include interest and service cost on the pension and other postretirement benefit plans, expected return on plan assets, and amortization of certain unrecognized costs and obligations. Actual results that differ from the assumptions utilized are accumulated and amortized over future periods and, therefore, generally affect recognized expense and the recorded obligation in future periods. While the Company believes that the assumptions used are appropriate, differences in actual experience or significant changes in assumptions would affect its pension and other postretirement benefits costs and obligations.

Key elements in determining the Company's pension and other postretirement benefit expense in accordance with GAAP are the expected long-term return on plan assets and the discount rate used to measure the benefit plan obligations and the periodic benefit plan expense for future periods. The expected long-term return on postretirement benefit plan assets is based on the Company's investment strategy, historical experience, and expectations for long-term rates of return that consider external actuarial advice. The Company determines the long-term return on plan assets by applying the long-term rate of expected returns on various asset classes to the Company's target asset allocation. The Company discounts the future cash flows related to its postretirement benefit plans using a single-point discount rate developed from the weighted average of market-observed yields for high quality fixed income securities with maturities that correspond to expected benefit payments.

A 25 basis point change in any significant assumption (discount rate, salaries, or long-term return on plan assets) would result in a $1.5 million or less change in total annual benefit expense and an $18.4 million or less change in projected obligations.

Allowance for Funds Used During Construction

In accordance with regulatory treatment, the Company records AFUDC, which represents the estimated debt and equity costs of capital funds that are necessary to finance the construction of new regulated facilities. While cash is not realized currently from such allowance, AFUDC increases the revenue requirement over the service life of the plant through a higher rate base and higher depreciation. The equity component of AFUDC is not included in the calculation of taxable income. The average annual AFUDC rate was 7.04%, 7.06%, and 7.33% for the years ended December 31, 2012, 2011, and 2010, respectively. The AFUDC rate is applied to CWIP consistent with jurisdictional regulatory treatment. AFUDC, net of income taxes, as a percentage of net income after dividends on preferred stock was 57.05%, 31.60%, and 6.97% for 2012, 2011, and 2010, respectively.

FINANCIAL CONDITION AND LIQUIDITY

Overview

The Company's financial condition remained stable at December 31, 2012. The Company's cash requirements primarily consist of funding ongoing operations, common stock dividends, capital expenditures, and debt maturities. Capital expenditures and other investing activities include investments to meet projected long-term demand requirements, to comply with environmental regulations, and for restoration following major storms. Operating cash flows provide a substantial portion of the Company's cash needs. For the three-year period from 2013 through 2015, the Company's projected common stock dividends, capital expenditures, and debt maturities are expected to exceed operating cash flows. Projected capital expenditures in that period include investments to build new generation facilities, to add environmental equipment for existing generating units, and to expand and improve transmission and distribution facilities. The Company plans to finance future cash needs in excess of its operating cash flows primarily through debt and equity issuances. The Company intends to continue to monitor its access to short-term and long-term capital markets as well as its bank credit arrangements to meet future capital and liquidity needs. See "Sources of Capital," "Financing Activities," and "Capital Requirements and Contractual Obligations" herein for additional information.

The Company's investments in the qualified pension plan increased in value as of December 31, 2012 as compared to December 31, 2011. In December 2012, the Company contributed $43.0 million to the qualified pension plan.

Net cash provided from operating activities totaled $235.4 million for 2012, an increase of $3.9 million as compared to the corresponding period in 2011. The increase in net cash provided from operating activities was primarily due to an increase in investment tax credits received related to the Kemper IGCC and an increase in over recovered regulatory clause revenues. The increase in cash provided from operating activities was partially offset by a contribution to the qualified pension plan in 2012, payments for fuel stock, and the settlement of interest rate swaps. Net cash provided from operating activities in 2011 totaled $231.5 million, an increase of $98.8 million compared to 2010. The increase in net cash provided from operating activities was primarily due to a decrease in the use of funds related to the Kemper IGCC generation construction screening costs incurred during 2010, cash payment made in 2010 to fund the qualified pension plan, and a decrease in prepaid income taxes. These increases in cash provided from operating activities were partially offset by a decrease in over recovered regulatory clause revenues and a decrease in fossil fuel stock.

Net cash used for investing activities totaled $1.5 billion for 2012 primarily due to an increase in property additions primarily related to the Kemper IGCC, partially offset by a decrease in restricted cash, a decrease in capital grant proceeds received primarily related to CCPI2 and Smart Grid Investment grants, and a decrease in plant acquisition due to the cash payment associated with the purchase of Plant Daniel Units 3 and 4 in 2011. Net cash used for investing activities in 2011 totaled $682.7 million primarily due to an increase in property additions primarily related to the Kemper IGCC and an increase in plant acquisition due to the cash payment associated with the purchase of Plant Daniel Units 3 and 4. These increases in cash used for investing activities were partially offset by an increase in construction payables, a change in restricted cash associated with the second series revenue bonds issued in 2010, and an increase in capital grant proceeds received primarily related to CCPI2 and Smart Grid Investment grants.

Net cash provided from financing activities totaled $1.2 billion in 2012 primarily due to an increase in capital contributions from Southern Company, an increase in long-term debt financings and the receipt of an interest bearing refundable deposit related to a pending asset sale, partially offset by redemptions of long-term debt financings. Net cash provided from financing activities totaled $502.0 million in 2011 primarily due to an increase in capital contributions from Southern Company, an increase in long-term debt, and redemptions of long-term debt financings.

Significant changes in the balance sheet as of December 31, 2012 compared to 2011 include an increase in prepaid income taxes of $92.0 million and an increase in accumulated deferred investment tax credits of $260.8 million primarily due to the Kemper IGCC investment tax credit. Total property, plant, and equipment increased $1.6 billion primarily due to the increase in CWIP related to the Kemper IGCC. Interest-bearing refundable deposit related to an asset sale increased $150.0 million due to the receipt of the $150.0 million interest-bearing refundable deposit from SMEPA. Long-term debt increased $460.9 million primarily due to the issuance of $600.0 million of senior notes, partially offset by the redemption of $90.0 million of senior notes and the reclassification of a $50.0 million long-term bank loan maturing in November 2013. Common stockholder's equity increased $748.2 million primarily due to the increase in paid-in capital due to $700.0 million in capital contributions from Southern Company in 2012.

The Company's ratio of common equity to total capitalization, excluding long-term debt due within one year, increased from 48.0% in 2011 to 52.9% at December 31, 2012.

Sources of Capital

Except as described herein, the Company plans to obtain the funds required for construction and other purposes from sources similar to those used in the past, which were primarily from operating cash flows, security issuances, term loans, short-term debt, and equity contributions from Southern Company. However, the amount, type, and timing of any future financings, if needed, will depend upon regulatory approval, prevailing market conditions, and other factors. In 2012, the Company received $700 million in capital contributions from Southern Company. On January 31, 2013, the Company received $100 million in additional capital contributions from Southern Company. See "Capital Requirements and Contractual Obligations" herein for additional information.

The Company has received $245.3 million in DOE CCPI2 grant funds that were used for the construction of the Kemper IGCC. An additional $25 million in CCPI2 grant funds is expected to be received for the initial operation of the Kemper IGCC. On January 29, 2013, the Company withdrew its application for federal loan guarantees related to the Kemper IGCC. See Note 3 to the financial statements under "Integrated Coal Gasification Combined Cycle" for information regarding legislation related to the securitization of certain costs of the Kemper IGCC.

Investment tax credits related to the Kemper IGCC of $170.9 million are not expected to be utilized until after 2013, which could result in additional financing needs. See Note 3 to the financial statements under "Integrated Coal Gasification Combined Cycle" for additional information.

The issuance of securities by the Company is subject to regulatory approval by the FERC. Additionally, with respect to the public offering of securities, the Company files registration statements with the Securities and Exchange Commission (SEC) under the Securities Act of 1933, as amended (1933 Act). The amounts of securities authorized by the FERC, as well as the amounts registered under the 1933 Act, are continuously monitored and appropriate filings are made to ensure flexibility in raising capital.

The Company obtains financing separately without credit support from any affiliate. See Note 6 to the financial statements under "Bank Credit Arrangements" for additional information. The Southern Company system does not maintain a centralized cash or money pool. Therefore, funds of the Company are not commingled with funds of any other company in the Southern Company system.

The Company's current liabilities frequently exceed current assets because of the continued use of short-term obligations as a funding source to meet scheduled maturities of long-term debt, as well as cash needs, which can fluctuate significantly due to the seasonality of the Company's business.

At December 31, 2012, the Company had approximately $145.0 million of cash and cash equivalents. Committed credit arrangements with banks at December 31, 2012 were as follows:

Expires[a]				Executable Term-Loans		Due Within One Year	
2013	2014	Total	Unused	One Year	Two Years	Term Out	No Term Out
		(in millions)					
$ 135	$ 165	$ 300	$ 300	$ 25	$ 40	$ 65	$ 70

(a) No credit arrangements expire after 2014.

See Note 6 to the financial statements under "Bank Credit Arrangements" for additional information.

Most of these arrangements contain covenants that limit debt levels and typically contain cross-default provisions that are restricted only to the indebtedness of the Company. The Company is currently in compliance with all such covenants. The Company expects to renew its credit arrangements, as needed prior to expiration.

These credit arrangements provide liquidity support to the Company's variable rate pollution control revenue bonds and commercial paper borrowings. The amount of variable rate pollution control revenue bonds outstanding requiring liquidity support as of December 31, 2012 was $40.1 million.

The Company may also meet short-term cash needs through a Southern Company subsidiary organized to issue and sell commercial paper at the request and for the benefit of the Company and the other traditional operating companies. Proceeds from such issuances for the benefit of the Company are loaned directly to the Company. The obligations of each traditional operating company under these arrangements are several and there is no cross affiliate credit support.

Details of short-term borrowings were as follows:

	Short-term Debt at the End of the Period		Short-term Debt During the Period [a]		
	Amount Outstanding	Weighted Average Interest Rate	Average Outstanding	Weighted Average Interest Rate	Maximum Amount Outstanding
	(in millions)		*(in millions)*		*(in millions)*
December 31, 2012:					
Commercial paper	$ —	—%	$ —	—%	$ —
December 31, 2011:					
Commercial paper	$ —	—%	$ 7	0.2%	$ 70
December 31, 2010:					
Commercial paper	$ —	—%	$ 12	0.3%	$ 63

(a) Average and maximum amounts are based upon daily balances during the twelve-month periods ended December 31, 2012, 2011, and 2010.

Management believes that the need for working capital can be adequately met by utilizing commercial paper programs, lines of credit, and cash.

Financing Activities

In addition to any financings that may be necessary to meet capital requirements, contractual obligations, and storm restoration costs, the Company plans to continue, when economically feasible, a program to retire higher-cost securities and replace these obligations with lower-cost capital if market conditions permit.

Bank Term Loans

In March 2012, the Company paid at maturity a $75 million aggregate principal amount variable rate bank note bearing interest at a rate based on one-month London Interbank Offered Rate (LIBOR).

In September 2012, the Company paid at maturity a $40 million aggregate principal amount variable rate bank note bearing interest at a rate based on one-month LIBOR.

In November 2012, the Company entered into a 366-day $100 million aggregate principal amount floating rate term loan agreement that bears interest based on one-month LIBOR. The first advance in the amount of $50 million was made in November 2012. Subsequent to December 31, 2012, the second advance in the amount of $50 million was made. The proceeds of this loan were used solely for working capital and other general corporate purposes, including the Company's continuous construction program.

Senior Notes

In March 2012, the Company issued $250 million aggregate principal amount of Series 2012A 4.25% Senior Notes due March 15, 2042 and an additional $150 million aggregate principal amount of Series 2011A 2.35% Senior Notes due October 15, 2016. The Series 2011A Senior Notes were of the same series of notes that were originally issued in October 2011 in the aggregate principal amount of $150 million. Upon completion of this offering, the aggregate principal amount of the outstanding Series 2011A Senior Notes was $300 million. The proceeds from the sales of the Series 2012A Senior Notes and the Series 2011A Senior Notes were used to repay a bank term loan in an aggregate principal amount of $75 million, bearing interest at a variable rate based on one-month LIBOR, and for general corporate purposes, including the Company's continuous construction program.

In March 2012, $300 million in interest rate swaps were settled, of which $250 million related to the Series 2012A Senior Notes at a loss of approximately $13.3 million, which will be amortized to interest expense, in earnings, over 10 years, and $50 million related to the Series 2011A Senior Notes at a loss of approximately $2.7 million, which will be amortized to interest expense, in earnings, over 10 years.

In May 2012, the Company redeemed $90 million aggregate principal amount of Series E 5-5/8% Senior Notes due May 1, 2033.

In August 2012, the Company issued an additional $200 million aggregate principal amount of Series 2012A 4.25% Senior Notes due March 15, 2042. The Series 2012A Senior Notes were of the same series of notes that were originally issued in March 2012 in the aggregate principal amount of $250 million. Upon completion of this offering, the aggregate principal amount of the outstanding Series 2012A Senior Notes is $450 million. The proceeds from this sale of the Series 2012A Senior Notes were used for general corporate purposes, including the Company's continuous construction program.

Other Revenue Bonds

In August 2012, the Mississippi Business Finance Corporation (MBFC) entered into an agreement to issue up to $42.50 million aggregate principal amount of MBFC Taxable Revenue Bonds, Series 2012A (Mississippi Power Company Project), up to $21.25 million aggregate principal amount of MBFC Taxable Revenue Bonds, Series 2012B (Mississippi Power Company Project), and up to $21.25 million aggregate principal amount of MBFC Taxable Revenue Bonds, Series 2012C (Mississippi Power Company Project) for the benefit of the Company. During 2012, the MBFC issued $8.97 million aggregate principal amount of MBFC Taxable Revenue Bonds (Mississippi Power Company Project), Series 2012A, $21.25 million aggregate principal amount of MBFC Taxable Revenue Bonds (Mississippi Power Company Project), Series 2012B, and $21.25 million aggregate principal amount of MBFC Taxable Revenue Bonds (Mississippi Power Company Project), Series 2012C for the benefit of the Company. The proceeds were used to reimburse the Company for the cost of the acquisition, construction, equipping, installation, and improvement of certain equipment and facilities for the lignite mining facility related to the Kemper IGCC. Any future issuances of the Series 2012A bonds will be used for this same purpose.

Other Obligations

In March 2012, the Company received a $150 million interest-bearing refundable deposit from SMEPA to be applied to the sale price for the pending sale of an undivided interest in the Kemper IGCC. Until the acquisition is closed, the deposit bears interest at the Company's AFUDC rate adjusted for income taxes, which was 9.967% per annum at December 31, 2012, and is refundable to SMEPA upon termination of the asset purchase agreement related to such purchase, within 60 days of a request by SMEPA for a full or partial refund, or within 15 days at SMEPA's discretion in the event that the Company is assigned a senior unsecured credit rating of BBB+ or lower by S&P or Baa1 or lower by Moody's or ceases to be rated by either of these rating agencies.

Purchase of the Plant Daniel Combined Cycle Generating Units

In 2001, the Company began the initial 10-year term of an operating lease agreement for Plant Daniel Units 3 and 4. In October 2011, the Company purchased Plant Daniel Units 3 and 4 for $84.8 million in cash and the assumption of $270.0 million face value of debt obligations of the lessor related to Plant Daniel Units 3 and 4, which mature in 2021 and bear interest at a fixed stated interest rate of 7.13% per annum. These obligations are secured by Plant Daniel Units 3 and 4 and certain personal property. Accounting rules require that Plant Daniel Units 3 and 4 be reflected on the Company's financial statements at the time of the purchase at the fair value of the consideration rendered. Based on interest rates as of October 20, 2011, the fair value of the debt assumed was $346.1 million. The fair value of the debt was determined using a discounted cash flow model based on the Company's borrowing rate at the closing date. The fair value is considered a Level 2 disclosure for financial reporting purposes. See Note 1 to the financial statements under "Purchase of the Plant Daniel Combined Cycle Generating Units" for additional information regarding the debt valuation. Accordingly, Plant Daniel Units 3 and 4 were reflected in the Company's financial statements at $430.9 million.

In connection with the purchase of Plant Daniel Units 3 and 4, the Company filed a request in July 2011 for an accounting order from the Mississippi PSC. This order, as approved on January 11, 2012, authorized the Company to defer as a regulatory asset, for the 10-year period ending October 2021, the difference between the revenue requirement under the purchase option for Plant Daniel Units 3 and 4 (assuming a remaining 30-year life) and the revenue requirement assuming the continuation of the operating lease regulatory treatment with the accumulated deferred balance at the end of the deferral being amortized into rates over the remaining life of Plant Daniel Units 3 and 4. In November 2011, the Company filed a request with the FERC seeking the same accounting and regulatory treatment for its wholesale cost-based jurisdiction. The total amount deferred in other regulatory assets, deferred at December 31, 2012 was $12.4 million. The ultimate outcome of this matter cannot be determined at this time.

Credit Rating Risk

The Company does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. There are certain contracts that could require collateral, but not accelerated payment, in the event of a credit rating change to below BBB- and/or Baa3. These contracts are for physical electricity sales, fuel purchases, fuel transportation and storage, emissions allowances, and energy price risk management. At December 31, 2012, the maximum potential collateral requirements under these contracts at a rating below BBB- and/or Baa3 were approximately $273 million.

Included in these amounts are certain agreements that could require collateral in the event that one or more Southern Company system power pool participants has a credit rating change to below investment grade. Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. Additionally, any credit rating downgrade could impact the Company's ability to access capital markets, particularly the short-term debt market and the variable rate pollution control revenue bond market.

In March 2012, the Company received a $150 million interest-bearing refundable deposit from SMEPA to be applied to the sale price for the pending sale of an undivided interest in the Kemper IGCC. Until the acquisition is closed, the deposit bears interest at the Company's AFUDC rate adjusted for income taxes, which was 9.967% per annum at December 31, 2012, and is refundable to SMEPA upon termination of the asset purchase agreement related to such purchase, within 60 days of a request by SMEPA for a full or partial refund, or within 15 days at SMEPA's discretion in the event that the Company is assigned a senior unsecured credit rating of BBB+ or lower by S&P or Baa1 or lower by Moody's or ceases to be rated by either of these rating agencies.

On July 3, 2012, Fitch downgraded the issuer default and unsecured long-term debt ratings of the Company to A- from A and to A from A+, respectively. Fitch also announced that it had downgraded the pollution control revenue bond ratings of the Company to A from A+ and the preferred stock ratings of the Company to BBB+ from A-. Fitch revised the ratings outlook for the Company to negative from stable.

On August 6, 2012, Moody's downgraded the senior unsecured debt and preferred stock ratings of the Company to A3 from A2 and to Baa2 from Baa1, respectively. Moody's revised the ratings outlook for the Company to negative from stable.

Market Price Risk

Due to cost-based rate regulation and other various cost recovery mechanisms, the Company continues to have limited exposure to market volatility in interest rates, foreign currency exchange rates, commodity fuel prices, and prices of electricity. To manage the volatility attributable to these exposures, the Company nets the exposures, where possible, to take advantage of natural offsets and enters into various derivative transactions for the remaining exposures pursuant to the Company's policies in areas such as counterparty exposure and risk management practices. The Company's policy is that derivatives are to be used primarily for hedging purposes and mandates strict adherence to all applicable risk management policies. Derivative positions are monitored using techniques that include, but are not limited to, market valuation, value at risk, stress testing, and sensitivity analysis.

To mitigate future exposure to changes in interest rates, the Company enters into derivatives that have been designated as hedges. The weighted average interest rate on $266.5 million of outstanding variable rate long-term debt at December 31, 2012 was 0.72%. If the Company sustained a 100 basis point change in interest rates for all unhedged variable rate long-term debt, the change would affect annualized interest expense by approximately $2.7 million at January 1, 2013. See Note 1 to the financial statements under "Financial Instruments" and Note 10 to the financial statements for additional information.

To mitigate residual risks relative to movements in electricity prices, the Company enters into fixed-price contracts for the purchase and sale of electricity through the wholesale electricity market. The Company continues to manage retail fuel hedging programs implemented per the guidelines of the Mississippi PSC and wholesale fuel hedging programs under agreements with wholesale customers. The Company had no material change in market risk exposure for the year ended December 31, 2012 when compared to the December 31, 2011 reporting period.

The changes in fair value of energy-related derivative contracts, substantially all of which are composed of regulatory hedges, for the years ended December 31 were as follows:

	2012 Changes	2011 Changes
	Fair Value	
	(in thousands)	
Contracts outstanding at the beginning of the period, assets (liabilities), net	$ **(50,990)**	$ (43,770)
Contracts realized or settled	**43,326**	32,381
Current period changes[(a)]	**(9,263)**	(39,601)
Contracts outstanding at the end of the period, assets (liabilities), net	$ **(16,927)**	$ (50,990)

(a) Current period changes also include the changes in fair value of new contracts entered into during the period, if any.

The changes in the fair value positions of the energy-related derivative contracts, which are substantially all attributable to both the volume and the price of natural gas, for the years ended December 31 were as follows:

	2012 Changes	2011 Changes
	Fair Value	
	(in thousands)	
Natural gas swaps	$ 26,020	$ 1,066
Natural gas options	8,085	(8,286)
Other energy related derivatives	(42)	—
Total changes	$ 34,063	$ (7,220)

The net hedge volumes of energy-related derivative contracts, for the years ended December 31 were as follows:

	2012	2011
	mmBtu* Volume	
	(in thousand)	
Commodity – Natural gas swaps	38,130	21,660
Commodity – Natural gas options	—	9,350
Total hedge volume	38,130	31,010

* million British thermal units (mmBtu)

The weighted average swap contract cost above market prices was approximately $0.44 per mmBtu as of December 31, 2012 and $1.98 per mmBtu as of December 31, 2011. The change in option fair value is primarily attributable to the volatility of the market and the underlying change in the natural gas price. The costs associated with natural gas hedges are recovered through the Company's energy cost management clauses.

At December 31, 2012 and 2011, substantially all of the Company's energy-related derivative contracts were designated as regulatory hedges and are related to the Company's fuel hedging program. Therefore, gains and losses are initially recorded as regulatory liabilities and assets, respectively, and then are included in fuel expense as they are recovered through the ECM clause. Gains and losses on energy-related derivatives that are designated as cash flow hedges are used to hedge anticipated purchases and sales and are initially deferred in other comprehensive income before being recognized in income in the same period as the hedged transaction. Gains and losses on energy-related derivative contracts that are not designated or fail to qualify as hedges are recognized in the statements of income as incurred and were not material for any year presented. The pre-tax gains and losses reclassified from other comprehensive income to revenue and fuel expense were not material for any period presented and are not expected to be material for 2013.

The Company uses over-the-counter contracts that are not exchange traded but are fair valued using prices which are market observable, and thus fall into Level 2. See Note 9 to the financial statements for further discussion of fair value measurements. The maturities of the energy-related derivative contracts, which are all Level 2 of the fair value hierarchy, at December 31, 2012 were as follows:

	Fair Value Measurements December 31, 2012			
	Total Fair Value	Maturity		
		Year 1	Years 2&3	Years 4&5
		(in thousands)		
Level 1	$ —	$ —	$ —	$ —
Level 2	(16,927)	(12,478)	(4,730)	281
Level 3	—	—	—	—
Fair value of contracts outstanding at end of period	$ (16,927)	$ (12,478)	$ (4,730)	$ 281

The Company is exposed to market price risk in the event of nonperformance by counterparties to the energy-related derivative contracts. The Company only enters into agreements and material transactions with counterparties that have investment grade credit ratings by Moody's and S&P or with counterparties who have posted collateral to cover potential credit exposure. Therefore, the Company does not anticipate market risk exposure from nonperformance by the counterparties. For additional information, see Note 1 to the financial statements under "Financial Instruments" and Note 10 to the financial statements.

Capital Requirements and Contractual Obligations

The construction program of the Company consists of a base level capital investment and capital expenditures to comply with existing environmental statutes and regulations. Included in the estimated base level capital investment amounts are expenditures related to the construction of the Kemper IGCC of $513 million and $218 million in 2013 and 2014, respectively, which are net of SMEPA's 15% proposed ownership share of the construction of the Kemper IGCC of approximately $492 million and $28 million in 2013 and 2014, respectively. The estimated share for SMEPA in 2013 reflects estimated construction costs relating to SMEPA's proposed ownership interest to be incurred through December 31, 2013 (including construction costs for all prior years relating to its proposed ownership interest). These estimated base level capital investment amounts also include capital expenditures covered under LTSAs, as well as capital expenditures and compliance costs associated with the MATS rule. Proposed water and coal combustion byproducts rules are not included in the construction program base level capital investment.

The Company's base level construction program investments for existing environmental statutes and regulations and the estimated incremental compliance costs related to the proposed water and coal combustion byproducts rules over the 2013 through 2015 three-year period, based on the assumption that coal combustion byproducts will continue to be regulated as non-hazardous solid waste under the proposed rule, are estimated as follows:

	2013	2014	2015
Construction program:		*(in millions)*	
Base capital	$ 667	$ 324	$ 139
Existing environmental statutes and regulations, including the MATS rule	129	174	116
Total construction program base level capital investment	**$ 796**	**$ 498**	**$ 255**
Potential incremental environmental compliance investment:			
Proposed water and coal combustion byproducts rules	$ —	$ 6	$ 28

See FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations" and – "Integrated Coal Gasification Combined Cycle" for additional information.

The construction program is subject to periodic review and revision, and actual construction costs may vary from these estimates because of numerous factors. These factors include: changes in business conditions; changes in load projections; storm impacts; changes in environmental statutes and regulations; the outcome of any legal challenges to environmental rules; changes in generating plants, including unit retirements and replacements and adding or changing fuel sources at existing units, to meet regulatory requirements; changes in FERC rules and regulations; Mississippi PSC approvals; changes in the expected environmental compliance program; changes in legislation; the cost and efficiency of construction labor, equipment, and materials; project scope and design changes; and the cost of capital. In addition, there can be no assurance that costs related to capital expenditures will be fully recovered. See Note 3 to the financial statements under "Integrated Coal Gasification Combined Cycle" for additional information.

In addition, as discussed in Note 2 to the financial statements, the Company provides postretirement benefits to substantially all employees and funds trusts to the extent required by the FERC.

Other funding requirements related to obligations associated with scheduled maturities of long-term debt, as well as the related interest, derivative obligations, preferred stock dividends, leases, and other purchase commitments are detailed in the contractual obligations table that follows. See Notes 1, 2, 5, 6, 7, and 10 to the financial statements for additional information.

Contractual Obligations

	2013	2014-2015	2016-2017	After 2017	Uncertain Timing [d]	Total
			(in thousands)			
Long-term debt[a] —						
Principal	$ 276,471	$ —	$ 335,000	$ 1,157,695	$ —	$ 1,769,166
Interest	71,290	132,879	125,829	819,619	—	1,149,617
Preferred stock dividends[b]	1,733	3,465	3,465	—	—	8,663
Financial derivative obligations[c]	13,116	6,202	165	—	—	19,483
Unrecognized tax benefits[d]	3,562	—	—	—	3,997	7,559
Operating leases [e]	11,232	11,648	1,920	—	—	24,800
Purchase commitments —						
Capital[f]	757,037	752,522	—	—	—	1,509,559
Fuel[g]	349,197	378,355	176,500	159,221	—	1,063,273
Long-term service agreements[h]	21,032	43,893	17,148	—	—	82,073
Pension and other postretirement benefits plans[i]	5,602	12,172	—	—	—	17,774
Total	$ 1,510,272	$ 1,341,136	$ 660,027	$ 2,136,535	$ 3,997	$ 5,651,967

(a) All amounts are reflected based on final maturity dates. The Company plans to continue to retire higher-cost securities and replace these obligations with lower-cost capital if market conditions permit. Variable rate interest obligations are estimated based on rates as of January 1, 2013, as reflected in the statements of capitalization. Fixed rates include, where applicable, the effects of interest rate derivatives employed to manage interest rate risk. Long-term debt excludes capital lease amounts.

(b) Preferred stock does not mature; therefore, amounts are provided for the next five years only.

(c) For additional information, see Notes 1 and 10 to the financial statements.

(d) The timing related to the realization of $4.0 million in unrecognized tax benefits in individual years beyond 12 months cannot be reasonably and reliably estimated due to uncertainties in the timing of the effective settlement of tax positions. See Note 5 to the financial statements under "Unrecognized Tax Benefits" for additional information.

(e) See Note 7 to the financial statements for additional information.

(f) The Company provides estimated capital expenditures for a three-year period, including capital expenditures and compliance costs associated with existing environmental regulations, including the MATS rule. Such amounts exclude the Company's estimates of potential incremental environmental compliance investment to comply with proposed water and coal combustion byproducts rules, which are approximately $6 million and $28 million for years 2014 and 2015, respectively. Estimates reflect the proposed sale of 15% of the Kemper IGCC to SMEPA. At December 31, 2012, significant purchase commitments were outstanding in connection with the construction program. These amounts exclude capital expenditures covered under long-term service agreements, which are reflected separately. See FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations" for additional information. See Note 3 to the financial statements under "Integrated Coal Gasification Combined Cycle" for additional information.

(g) Includes commitments to purchase coal and natural gas, as well as the related transportation and storage. In most cases, these contracts contain provisions for price escalation, minimum purchase levels, and other financial commitments. Natural gas purchase commitments are based on various indices at the time of delivery. Amounts reflected for natural gas purchase commitments have been estimated based on the New York Mercantile Exchange future prices at December 31, 2012.

(h) Long-term service agreements include price escalation based on inflation indices.

(i) The Company forecasts contributions to the pension and other postretirement benefit plans over a three-year period. The Company anticipates no mandatory contributions to the qualified pension plan during the next three years. Amounts presented represent estimated benefit payments for the nonqualified pension plans, estimated non-trust benefit payments for the other postretirement benefit plans, and estimated contributions to the other postretirement benefit plan trusts, all of which will be made from the Company's corporate assets. See Note 2 to the financial statements for additional information related to the pension and other postretirement benefit plans, including estimated benefit payments. Certain benefit payments will be made through the related benefit plans. Other benefit payments will be made from the Company's corporate assets.

Cautionary Statement Regarding Forward-Looking Statements

The Company's 2012 Annual Report contains forward-looking statements. Forward-looking statements include, among other things, statements concerning retail sales, retail rates, customer growth, fuel and environmental cost recovery and other rate actions, current and proposed environmental regulations and related estimated expenditures, access to sources of capital, projections for the qualified pension plan and postretirement benefit plan, financing activities, start and completion of construction projects, plans and estimated costs for new generation resources, filings with state and federal regulatory authorities, impact of the Tax Relief Act, impact of the ATRA, estimated sales and purchases under new power sale and purchase agreements, storm damage cost recovery and repairs, economic recovery, and estimated construction and other expenditures. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "could," "should," "expects," "plans," "anticipates," "believes," "estimates," "projects," "predicts," "potential," or "continue" or the negative of these terms or other similar terminology. There are various factors that could cause actual results to differ materially from those suggested by the forward-looking statements; accordingly, there can be no assurance that such indicated results will be realized. These factors include:

- the impact of recent and future federal and state regulatory changes, including legislative and regulatory initiatives regarding deregulation and restructuring of the electric utility industry, environmental laws including regulation of water, coal combustion byproducts, and emissions of sulfur, nitrogen, carbon, soot, particulate matter, hazardous air pollutants, including mercury, and other substances, financial reform legislation, and also changes in tax and other laws and regulations to which the Company is subject, as well as changes in application of existing laws and regulations;
- current and future litigation, regulatory investigations, proceedings, or inquiries, including FERC matters, the pending EPA civil action, and IRS and state tax audits;
- the effects, extent, and timing of the entry of additional competition in the markets in which the Company operates;
- variations in demand for electricity, including those relating to weather, the general economy and recovery from the recent recession, population and business growth (and declines), the effects of energy conservation measures, and any potential economic impacts resulting from federal fiscal decisions;
- available sources and costs of fuels;
- effects of inflation;
- ability to control costs and avoid cost overruns during the development and construction of facilities, including the development and construction of facilities with designs that have not been finalized or previously constructed, to construct facilities in accordance with the requirements of permits and licenses, and to satisfy any operational and environmental performance standards, including the requirements of tax credits and other incentives;
- investment performance of the Company's employee benefit plans;
- advances in technology;
- state and federal rate regulations and the impact of pending and future rate cases and negotiations, including rate actions relating to fuel and other cost recovery mechanisms;
- regulatory approvals and legislative actions related to the Kemper IGCC, including Mississippi PSC approvals and legislation relating to cost recovery for the Kemper IGCC, the SMEPA purchase decision, satisfaction of requirements to utilize investment tax credits and grants, and the outcome of any proceedings regarding the Mississippi PSC's issuance of the CPCN for the Kemper IGCC;
- internal restructuring or other restructuring options that may be pursued;
- potential business strategies, including acquisitions or dispositions of assets or businesses, which cannot be assured to be completed or beneficial to the Company;
- the ability of counterparties of the Company to make payments as and when due and to perform as required;
- the ability to obtain new short- and long-term contracts with wholesale customers;
- the direct or indirect effect on the Company's business resulting from terrorist incidents and the threat of terrorist incidents, including cyber intrusion;
- interest rate fluctuations and financial market conditions and the results of financing efforts, including the Company's credit ratings;
- the impacts of any potential U.S. credit rating downgrade or other sovereign financial issues, including impacts on interest rates, access to capital markets, impacts on currency exchange rates, counterparty performance, and the economy in general, as well as potential impacts on the availability or benefits of proposed DOE loan guarantees;

- the ability of the Company to obtain additional generating capacity at competitive prices;
- catastrophic events such as fires, earthquakes, explosions, floods, hurricanes, droughts, pandemic health events such as influenzas, or other similar occurrences;
- the direct or indirect effects on the Company's business resulting from incidents affecting the U.S. electric grid or operation of generating resources;
- the effect of accounting pronouncements issued periodically by standard setting bodies; and
- other factors discussed elsewhere herein and in other reports (including the Form 10-K) filed by the Company from time to time with the SEC.

The Company expressly disclaims any obligation to update any forward-looking statements.

STATEMENTS OF INCOME
For the Years Ended December 31, 2012, 2011, and 2010
Mississippi Power Company 2012 Annual Report

	2012	2011	2010
		(in thousands)	
Operating Revenues:			
Retail revenues	**$ 747,453**	$ 792,463	$ 797,912
Wholesale revenues, non-affiliates	**255,557**	273,178	287,917
Wholesale revenues, affiliates	**16,403**	30,417	41,614
Other revenues	**16,583**	16,819	15,625
Total operating revenues	**1,035,996**	1,112,877	1,143,068
Operating Expenses:			
Fuel	**411,226**	490,415	501,830
Purchased power, non-affiliates	**5,221**	6,239	8,426
Purchased power, affiliates	**49,907**	65,574	75,230
Other operations and maintenance	**228,675**	266,395	268,063
Depreciation and amortization	**86,510**	80,337	76,891
Taxes other than income taxes	**79,445**	70,127	69,810
Total operating expenses	**860,984**	979,087	1,000,250
Operating Income	**175,012**	133,790	142,818
Other Income and (Expense):			
Allowance for equity funds used during construction	**64,793**	24,707	3,795
Interest income	**745**	1,347	215
Interest expense, net of amounts capitalized	**(40,838)**	(21,691)	(22,341)
Other income (expense), net	**519**	(45)	3,738
Total other income and (expense)	**25,219**	4,318	(14,593)
Earnings Before Income Taxes	**200,231**	138,108	128,225
Income taxes	**50,391**	42,193	46,275
Net Income	**149,840**	95,915	81,950
Dividends on Preferred Stock	**1,733**	1,733	1,733
Net Income After Dividends on Preferred Stock	**$ 148,107**	$ 94,182	$ 80,217

The accompanying notes are an integral part of these financial statements.

STATEMENTS OF COMPREHENSIVE INCOME
For the Years Ended December 31, 2012, 2011, and 2010
Mississippi Power Company 2012 Annual Report

	2012	2011	2010
		(in thousands)	
Net Income	**$ 149,840**	$ 95,915	$ 81,950
Other comprehensive income (loss):			
Qualifying hedges:			
Changes in fair value, net of tax of $(296), $(5,494), and $1, respectively	**(479)**	(8,870)	2
Reclassification adjustment for amounts included in net income, net of tax of $411, $(18), and $-, respectively	**663**	(29)	—
Total other comprehensive income (loss)	**184**	(8,899)	2
Comprehensive Income	**$ 150,024**	$ 87,016	$ 81,952

The accompanying notes are an integral part of these financial statements.

STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2012, 2011, and 2010
Mississippi Power Company 2012 Annual Report

	2012	2011	2010
		(in thousands)	
Operating Activities:			
Net income	$ 149,840	$ 95,915	$ 81,950
Adjustments to reconcile net income to net cash provided from operating activities —			
Depreciation and amortization, total	86,981	83,787	82,294
Deferred income taxes	47,523	71,764	37,557
Investment tax credits received	82,464	—	22,173
Allowance for equity funds used during construction	(64,793)	(24,707)	(3,795)
Pension, postretirement, and other employee benefits	(35,425)	3,169	(34,911)
Hedge settlements	(15,983)	848	—
Stock based compensation expense	2,084	1,548	1,186
Generation construction screening costs	—	—	(50,554)
Regulatory assets associated with Kemper IGCC	(15,445)	(7,719)	(12,292)
Other, net	10,516	(433)	8,888
Changes in certain current assets and liabilities —			
-Receivables	(6,589)	5,864	(8,185)
-Fossil fuel stock	(36,206)	(27,933)	14,997
-Materials and supplies	(3,473)	(2,116)	(879)
-Prepaid income taxes	(3,852)	12,907	(17,075)
-Other current assets	(19,851)	1,606	(4,633)
-Other accounts payable	8,814	24,143	(12,630)
-Accrued interest	17,627	6,817	194
-Accrued taxes	13,768	1,209	(4,268)
-Accrued compensation	(183)	(187)	2,291
-Over recovered regulatory clause revenues	16,836	(16,544)	28,450
-Other current liabilities	757	1,557	1,943
Net cash provided from operating activities	235,410	231,495	132,701
Investing Activities:			
Property additions	(1,620,047)	(964,233)	(247,005)
Plant acquisition	—	(84,803)	—
Investment in restricted cash	—	—	(50,000)
Distribution of restricted cash	—	50,000	—
Cost of removal net of salvage	(4,355)	(7,432)	(9,240)
Construction payables	78,961	97,079	33,767
Capital grant proceeds	13,372	232,442	23,657
Other investing activities	(16,706)	(5,736)	(5,587)
Net cash used for investing activities	(1,548,775)	(682,683)	(254,408)
Financing Activities:			
Proceeds —			
Capital contributions from parent company	702,971	299,305	65,215
Bonds-Other	51,471	—	—
Senior notes issuances	600,000	300,000	—
Interest-bearing refundable deposit related to asset sale	150,000	—	—
Other long-term debt issuances	50,000	115,000	225,000
Redemptions —			
Capital leases	(633)	(1,437)	(1,330)
Senior notes	(90,000)	—	—
Other long-term debt	(115,000)	(130,000)	—
Payment of preferred stock dividends	(1,733)	(1,733)	(1,733)
Payment of common stock dividends	(106,800)	(75,500)	(68,600)
Other financing activities	6,512	(3,641)	(1,091)
Net cash provided from (used for) financing activities	1,246,788	501,994	217,461
Net Change in Cash and Cash Equivalents	(66,577)	50,806	95,754
Cash and Cash Equivalents at Beginning of Year	211,585	160,779	65,025
Cash and Cash Equivalents at End of Year	$ 145,008	$ 211,585	$ 160,779
Supplemental Cash Flow Information:			
Cash paid during the period for —			
Interest (net of $32,816, $10,065 and $2,903 capitalized, respectively)	$ 32,589	$ 14,814	$ 19,518
Income taxes (net of refunds)	(77,580)	(41,024)	7,546
Noncash transactions — accrued property additions at year-end	214,863	135,902	37,736
Assumption of debt due to plant acquisition	—	346,051	—

The accompanying notes are an integral part of these financial statements.

BALANCE SHEETS
At December 31, 2012 and 2011
Mississippi Power Company 2012 Annual Report

Assets	2012	2011
		(in thousands)
Current Assets:		
Cash and cash equivalents	**$ 145,008**	$ 211,585
Receivables —		
Customer accounts receivable	**29,561**	32,551
Unbilled revenues	**32,688**	27,239
Other accounts and notes receivable	**7,517**	7,080
Affiliated companies	**27,160**	23,078
Accumulated provision for uncollectible accounts	**(373)**	(547)
Fossil fuel stock, at average cost	**176,378**	140,173
Materials and supplies, at average cost	**34,260**	30,787
Other regulatory assets, current	**55,302**	69,201
Prepaid income taxes	**129,835**	37,793
Other current assets	**17,170**	8,881
Total current assets	**654,506**	587,821
Property, Plant, and Equipment:		
In service	**3,036,159**	2,902,240
Less accumulated provision for depreciation	**1,065,474**	1,019,251
Plant in service, net of depreciation	**1,970,685**	1,882,989
Construction work in progress	**2,471,145**	955,135
Total property, plant, and equipment	**4,441,830**	2,838,124
Other Property and Investments	**4,887**	6,520
Deferred Charges and Other Assets:		
Deferred charges related to income taxes	**71,869**	25,009
Other regulatory assets, deferred	**236,225**	185,694
Other deferred charges and assets	**42,304**	28,674
Total deferred charges and other assets	**350,398**	239,377
Total Assets	**$ 5,451,621**	$ 3,671,842

The accompanying notes are an integral part of these financial statements.

BALANCE SHEETS
At December 31, 2012 and 2011
Mississippi Power Company 2012 Annual Report

Liabilities and Stockholder's Equity	2012	2011
		(in thousands)
Current Liabilities:		
Securities due within one year	**$ 276,471**	$ 240,633
Interest-bearing refundable deposit related to asset sale	**150,000**	—
Accounts payable —		
Affiliated	**54,769**	62,650
Other	**262,992**	168,309
Customer deposits	**14,202**	13,658
Accrued taxes —		
Accrued income taxes	**2,339**	3,813
Other accrued taxes	**69,376**	53,825
Accrued interest	**30,376**	12,750
Accrued compensation	**15,706**	15,889
Other regulatory liabilities, current	**5,376**	5,779
Over recovered regulatory clause liabilities	**77,338**	60,502
Liabilities from risk management activities	**13,116**	54,127
Other current liabilities	**18,766**	17,533
Total current liabilities	**990,827**	709,468
Long-Term Debt (See accompanying statements)	**1,564,462**	1,103,596
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	**274,793**	270,397
Deferred credits related to income taxes	**10,106**	11,058
Accumulated deferred investment tax credits	**370,554**	109,761
Employee benefit obligations	**157,421**	161,065
Other cost of removal obligations	**143,461**	126,424
Other regulatory liabilities, deferred	**56,984**	60,848
Other deferred credits and liabilities	**52,860**	37,228
Total deferred credits and other liabilities	**1,066,179**	776,781
Total Liabilities	**3,621,468**	2,589,845
Cumulative Redeemable Preferred Stock (See accompanying statements)	**32,780**	32,780
Common Stockholder's Equity (See accompanying statements)	**1,797,373**	1,049,217
Total Liabilities and Stockholder's Equity	**$ 5,451,621**	$ 3,671,842
Commitments and Contingent Matters (See notes)		

The accompanying notes are an integral part of these financial statements.

STATEMENTS OF CAPITALIZATION
At December 31, 2012 and 2011
Mississippi Power Company 2012 Annual Report

	2012	2011	2012	2011
	(in thousands)		*(percent of total)*	
Long-Term Debt:				
Long-term notes payable —				
6.00% due 2013	**$ 50,000**	$ 50,000		
2.35% due 2016	**300,000**	150,000		
5.60% due 2017	**35,000**	35,000		
2.25% to 5.63% due 2019-2042	**805,000**	445,000		
Adjustable rates (0.60% to 0.85% at 1/1/12) due 2012	**—**	240,000		
Adjustable rates (0.63% to 1.21% at 1/1/13) due 2013	**226,471**	—		
Total long-term notes payable	**1,416,471**	920,000		
Other long-term debt —				
Pollution control revenue bonds:				
5.15% due 2028	**42,625**	42,625		
Variable rates (0.12% to 0.14% at 1/1/13) due 2020-2028	**40,070**	40,070		
Plant Daniel revenue bonds (7.13%) due 2021	**270,000**	270,000		
Total other long-term debt	**352,695**	352,695		
Capitalized lease obligations	**—**	633		
Unamortized debt premium	**80,912**	74,551		
Unamortized debt discount	**(9,145)**	(3,650)		
Total long-term debt (annual interest requirement — $71.3 million)	**1,840,933**	1,344,229		
Less amount due within one year	**276,471**	240,633		
Long-term debt excluding amount due within one year	**1,564,462**	1,103,596	**46.1%**	50.5%
Cumulative Redeemable Preferred Stock:				
$100 par value				
Authorized: 1,244,139 shares				
Outstanding: 334,210 shares				
4.40% to 5.25% (annual dividend requirement — $1.7 million)	**32,780**	32,780	**1.0**	1.5
Common Stockholder's Equity:				
Common stock, without par value —				
Authorized: 1,130,000 shares				
Outstanding: 1,121,000 shares	**37,691**	37,691		
Paid-in capital	**1,401,520**	694,855		
Retained earnings	**366,875**	325,568		
Accumulated other comprehensive income (loss)	**(8,713)**	(8,897)		
Total common stockholder's equity	**1,797,373**	1,049,217	**52.9**	48.0
Total Capitalization	**$ 3,394,615**	$ 2,185,593	**100.0%**	100.0%

The accompanying notes are an integral part of these financial statements.

STATEMENTS OF COMMON STOCKHOLDER'S EQUITY
For the Years Ended December 31, 2012, 2011, and 2010
Mississippi Power Company 2012 Annual Report

	Number of Common Shares Issued	Common Stock	Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
			(in thousands)			
Balance at December 31, 2009	1,121	$ 37,691	$ 325,562	$295,269	$ —	$ 658,522
Net income after dividends on preferred stock	—	—	—	80,217	—	80,217
Capital contributions from parent company	—	—	67,228	—	—	67,228
Other comprehensive income (loss)	—	—	—	—	2	2
Cash dividends on common stock	—	—	—	(68,600)	—	(68,600)
Other	—	—	—	(1)	—	(1)
Balance at December 31, 2010	1,121	37,691	392,790	306,885	2	737,368
Net income after dividends on preferred stock	—	—	—	94,182	—	94,182
Capital contributions from parent company	—	—	302,065	—	—	302,065
Other comprehensive income (loss)	—	—	—	—	(8,899)	(8,899)
Cash dividends on common stock	—	—	—	(75,500)	—	(75,500)
Other	—	—	—	1	—	1
Balance at December 31, 2011	**1,121**	**37,691**	**694,855**	**325,568**	**(8,897)**	**1,049,217**
Net income after dividends on preferred stock	—	—	—	**148,107**	—	**148,107**
Capital contributions from parent company	—	—	**706,665**	—	—	**706,665**
Other comprehensive income (loss)	—	—	—	—	**184**	**184**
Cash dividends on common stock	—	—	—	**(106,800)**	—	**(106,800)**
Balance at December 31, 2012	**1,121**	**$ 37,691**	**$1,401,520**	**$366,875**	**$ (8,713)**	**$1,797,373**

The accompanying notes are an integral part of these financial statements.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

General

Mississippi Power Company (the Company) is a wholly owned subsidiary of The Southern Company (Southern Company), which is the parent company of the Company and three other traditional operating companies, as well as Southern Power Company (Southern Power), Southern Company Services, Inc. (SCS), Southern Communications Services, Inc. (SouthernLINC Wireless), Southern Company Holdings, Inc. (Southern Holdings), Southern Nuclear Operating Company, Inc. (Southern Nuclear), and other direct and indirect subsidiaries. The traditional operating companies – Alabama Power Company (Alabama Power), Georgia Power Company (Georgia Power), Gulf Power Company (Gulf Power), and the Company – are vertically integrated utilities providing electric service in four Southeastern states. The Company operates as a vertically integrated utility providing electricity to retail customers in southeast Mississippi and to wholesale customers in the Southeast. Southern Power constructs, acquires, owns, and manages generation assets, including renewable energy projects, and sells electricity at market-based rates in the wholesale market. SCS, the system service company, provides, at cost, specialized services to Southern Company and its subsidiary companies. SouthernLINC Wireless provides digital wireless communications for use by Southern Company and its subsidiary companies and also markets these services to the public and provides fiber cable services within the Southeast. Southern Holdings is an intermediate holding company subsidiary, primarily for Southern Company's investments in leveraged leases. Southern Nuclear operates and provides services to the Southern Company system's nuclear power plants.

The equity method is used for entities in which the Company has significant influence but does not control and for variable interest entities (VIEs) where the Company has an equity investment, but is not the primary beneficiary.

The Company is subject to regulation by the Federal Energy Regulatory Commission (FERC) and the Mississippi Public Service Commission (PSC). The Company follows generally accepted accounting principles (GAAP) in the U.S. and complies with the accounting policies and practices prescribed by its regulatory commissions. The preparation of financial statements in conformity with GAAP requires the use of estimates, and the actual results may differ from those estimates. Certain prior years' data presented in the financial statements have been reclassified to conform to the current year presentation.

Affiliate Transactions

The Company has an agreement with SCS under which the following services are rendered to the Company at direct or allocated cost: general and design engineering, operations, purchasing, accounting, finance and treasury, tax, information technology, marketing, auditing, insurance and pension administration, human resources, systems and procedures, digital wireless communications, and other services with respect to business and operations and power pool transactions. Costs for these services amounted to $212.7 million, $185.5 million, and $125.1 million during 2012, 2011, and 2010, respectively. The increase in 2012 and 2011 SCS costs is primarily due to the construction of the new integrated coal gasification combined cycle (IGCC) electric generating plant located in Kemper County, Mississippi (Kemper IGCC) and the construction of a flue gas desulfurization system (scrubber) on Plant Daniel Units 1 and 2. Cost allocation methodologies used by SCS prior to the repeal of the Public Utility Holding Company Act of 1935, as amended, were approved by the Securities and Exchange Commission (SEC). Subsequently, additional cost allocation methodologies have been reported to the FERC and management believes they are reasonable. The FERC permits services to be rendered at cost by system service companies.

The Company has an agreement with Alabama Power under which the Company owns a portion of Greene County Steam Plant. Alabama Power operates Greene County Steam Plant, and the Company reimburses Alabama Power for its proportionate share of non-fuel expenditures and costs, which totaled $11.7 million, $12.2 million, and $11.2 million in 2012, 2011, and 2010, respectively. Also, the Company reimburses Alabama Power for any direct fuel purchases delivered from an Alabama Power transfer facility, which were $28.1 million in 2012, $20.9 million in 2011, and $16.1 million in 2010. The Company also has an agreement with Gulf Power under which Gulf Power owns a portion of Plant Daniel. The Company operates Plant Daniel, and Gulf Power reimburses the Company for its proportionate share of all associated expenditures and costs, which totaled $21.2 million, $23.3 million, and $25.0 million in 2012, 2011, and 2010, respectively. See Note 4 for additional information.

The Company also provides incidental services to and receives such services from other Southern Company subsidiaries which are generally minor in duration and amount. Except as described herein, the Company neither provided nor received any material services to or from affiliates in 2011 and 2010. The Company received storm assistance from other Southern Company subsidiaries totaling $2.0 million in 2012. There was no significant storm assistance received from affiliates in 2011 or 2010.

The traditional operating companies, including the Company, and Southern Power may jointly enter into various types of wholesale energy, natural gas, and certain other contracts, either directly or through SCS, as agent. Each participating company may be jointly and severally liable for the obligations incurred under these agreements. See Note 7 under "Fuel and Purchased Power Agreements" for additional information.

New Accounting Pronouncements

In June 2011, the Financial Accounting Standards Board (FASB) issued guidance, ASU 2011-05, *Presentation of Comprehensive Income*, requiring companies to present the total of comprehensive income, the components of net income, and the components of other comprehensive income, in a single continuous statement of comprehensive income or in two separate but consecutive statements. In October 2012, the FASB issued additional guidance, ASU 2012-04, *Technical Corrections and Improvements* (ASU 2012-04), in which it clarified that those companies presenting consecutive statements must begin the statement of comprehensive income with net income. The Company retroactively adopted the guidance in ASU 2012-04 beginning with its financial statements for the three years ended December 31, 2012, 2011, and 2010.

Regulatory Assets and Liabilities

The Company is subject to the provisions of the FASB in accounting for the effects of rate regulation. Regulatory assets represent probable future revenues associated with certain costs that are expected to be recovered from customers through the ratemaking process. Regulatory liabilities represent probable future reductions in revenues associated with amounts that are expected to be credited to customers through the ratemaking process.

Regulatory assets and (liabilities) reflected in the balance sheets at December 31 relate to:

	2012	2011	Note
		(in thousands)	
Retiree benefit plans	$ 162,293	$ 130,678	(a,g)
Property damage	(58,789)	(64,748)	(i)
Deferred income tax charges	68,175	21,000	(c)
Property tax	27,882	18,484	(d)
Vacation pay	9,635	9,128	(e,g)
Loss on reacquired debt	9,815	7,171	(k)
Plant Daniel Units 3 and 4 regulatory assets	12,386	3,945	(j)
Other regulatory assets	2,035	132	(b)
Fuel hedging (realized and unrealized) losses	20,906	54,103	(f,g)
Asset retirement obligations	9,353	9,057	(c)
Deferred income tax credits	(11,157)	(12,081)	(c)
Other cost of removal obligations	(143,461)	(126,424)	(c)
Fuel hedging (realized and unrealized) gains	(2,519)	(162)	(f,g)
Kemper IGCC regulatory assets	36,047	20,684	(h)
Other regulatory liabilities	—	(693)	(b)
Deferred income tax charges — Medicare subsidy	4,868	5,521	(l)
Total regulatory assets (liabilities), net	$ 147,469	$ 75,795	

Note: The recovery and amortization periods for these regulatory assets and (liabilities) are as follows:

(a) Recovered and amortized over the average remaining service period which may range up to 14 years. See Note 2 for additional information.

(b) Recorded and recovered as approved by the Mississippi PSC.

(c) Asset retirement and removal assets and liabilities and deferred income tax assets are recovered, and removal assets and deferred income tax liabilities are amortized over the related property lives, which may range up to 50 years. Asset retirement and removal assets and liabilities will be settled and trued up following completion of the related activities.

(d) Recovered through the ad valorem tax adjustment clause over a 12-month period beginning in April of the following year.

(e) Recorded as earned by employees and recovered as paid, generally within one year. This includes both vacation and banked holiday pay.

(f) Fuel hedging assets and liabilities are recorded over the life of the underlying hedged purchase contracts, which generally do not exceed two years. Upon final settlement, costs are recovered through the Energy Cost Management clause (ECM).

(g) Not earning a return as offset in rate base by a corresponding asset or liability.

(h) For additional information, see Note 3 under "Integrated Coal Gasification Combined Cycle."

(i) For additional information, see Note 1 under "Provision for Property Damage" and Note 3 under "Retail Regulatory Matters – System Restoration Rider."

(j) Recovered and amortized over a 10-year period ending October 2021, as approved by the Mississippi PSC for the difference between the revenue requirement under the purchase option and the revenue requirement assuming operating lease accounting treatment for the extended term.

(k) Recovered over the remaining life of the original issue or, if refinanced, over the life of the new issue, which may range up to 50 years.

(l) Recovered and amortized over a 10-year period beginning in 2012, as approved by the Mississippi PSC for the retail portion and a five-year period for the wholesale portion, as approved by FERC.

In the event that a portion of the Company's operations is no longer subject to applicable accounting rules for rate regulation, the Company would be required to write off to income or reclassify to accumulated other comprehensive income (OCI) related regulatory assets and liabilities that are not specifically recoverable through regulated rates. In addition, the Company would be required to determine if any impairment to other assets, including plant, exists and write down the assets, if impaired, to their fair values. All regulatory assets and liabilities are to be reflected in rates. See Note 3 under "Retail Regulatory Matters" and "Integrated Coal Gasification Combined Cycle" for additional information.

Government Grants

In 2008, the Company requested that the Department of Energy (DOE) transfer the remaining funds previously granted under the Clean Coal Power Initiative Round 2 (CCPI2) from a cancelled IGCC project of one of Southern Company's subsidiaries that would have been located in Orlando, Florida. In 2010, the DOE, through a cooperative agreement with SCS, agreed to fund $270.0 million of the Kemper IGCC through the CCPI2 funds. Through December 31, 2012, the Company has received grant funds of $245.3 million, used for the construction of the Kemper IGCC, which is reflected in the Company's financial statements as a reduction to the Kemper IGCC capital costs. An additional $25.0 million is expected to be received for its initial operation.

Revenues

Energy and other revenues are recognized as services are provided. Wholesale capacity revenues from long-term contracts are recognized at the lesser of the levelized amount or the amount billable under the contract over the respective contract period. Unbilled revenues related to retail sales are accrued at the end of each fiscal period. The Company's retail and wholesale rates include provisions to adjust billings for fluctuations in fuel costs, fuel hedging, the energy component of purchased power costs, and certain other costs. Retail rates also include provisions to adjust billings for fluctuations in costs for ad valorem taxes and certain qualifying environmental costs. Revenues are adjusted for differences between these actual costs and amounts billed in current regulated rates. Under or over recovered regulatory clause revenues are recorded in the balance sheets and are recovered or returned to customers through adjustments to the billing factors. The Company is required to file with the Mississippi PSC for an adjustment to the fuel cost recovery factor annually.

The Company serves long-term contracts with rural electric cooperative associations and municipalities located in southeastern Mississippi under cost-based electric tariffs which are subject to regulation by the FERC. The contracts with these wholesale customers represented 22% of the Company's total operating revenues in 2012 and are largely subject to rolling 10-year cancellation notices.

The Company has a diversified base of customers. No single customer or industry comprises 10% or more of revenues. For all periods presented, uncollectible accounts averaged less than 1% of revenues.

Fuel Costs

Fuel costs are expensed as the fuel is used. Fuel expense generally includes fuel transportation costs and the cost of purchased emissions allowances as they are used. Fuel costs also include gains and/or losses from fuel hedging programs as approved by the Mississippi PSC.

Income and Other Taxes

The Company uses the liability method of accounting for deferred income taxes and provides deferred income taxes for all significant income tax temporary differences. Investment tax credits utilized are deferred and amortized to income over the average life of the related property. Taxes that are collected from customers on behalf of governmental agencies to be remitted to these agencies are presented net on the statements of income.

In accordance with accounting standards related to the uncertainty in income taxes, the Company recognizes tax positions that are "more likely than not" of being sustained upon examination by the appropriate taxing authorities. See Note 5 under "Unrecognized Tax Benefits" for additional information.

Property, Plant, and Equipment

Property, plant, and equipment is stated at original cost less any regulatory disallowances and impairments. Original cost includes: materials; labor; minor items of property; appropriate administrative and general costs; payroll-related costs such as taxes, pensions, and other benefits; and the interest capitalized and cost of equity funds used during construction for projects where recovery of construction work in progress (CWIP) is not allowed in rates.

The Company's property, plant, and equipment in service consisted of the following at December 31:

	2012	2011
	(in thousands)	
Generation	$ **1,363,269**	$ 1,362,567
Transmission	**563,037**	497,202
Distribution	**802,718**	784,655
General	**225,723**	176,408
Plant acquisition adjustment	**81,412**	81,408
Total plant in service	$ **3,036,159**	$ 2,902,240

The cost of replacements of property, exclusive of minor items of property, is capitalized. The cost of maintenance, repairs, and replacement of minor items of property is charged to other operations and maintenance expense except for the cost of maintenance of coal cars and a portion of the railway track maintenance costs, which are charged to fuel stock and recovered through the Company's fuel clause.

Purchase of the Plant Daniel Combined Cycle Generating Units

In 2001, the Company began the initial 10-year term of an operating lease agreement for the combined cycle generating Units 3 and 4 at Plant Daniel (Plant Daniel Units 3 and 4). In October 2011, the Company purchased Plant Daniel Units 3 and 4 for $84.8 million in cash and the assumption of $270.0 million face value of debt obligations of the lessor related to Plant Daniel Units 3 and 4, which mature in 2021 and bear interest at a fixed stated interest rate of 7.13% per annum. These obligations are secured by Plant Daniel Units 3 and 4 and certain personal property. Accounting rules require that Plant Daniel Units 3 and 4 be reflected on the Company's financial statements at the time of the purchase at the fair value of the consideration rendered. Based on interest rates as of October 20, 2011, the fair value of the debt assumed was $346.1 million. The fair value of the debt was determined using a discounted cash flow model based on the Company's borrowing rate at the closing date. The fair value is considered a Level 2 disclosure for financial reporting purposes. Accordingly, Plant Daniel Units 3 and 4 were reflected in the Company's financial statements as follows:

	(in thousands)
Assumption of debt obligations	$ 270,000
Fair value adjustment at date of purchase	76,051
Total debt	346,051
Cash payment for the purchase	84,803
Total value of Plant Daniel Units 3 and 4	$ 430,854

See Note 3 under "Retail Regulatory Matters – Performance Evaluation Plan" for additional information.

Depreciation and Amortization

Depreciation of the original cost of plant in service is provided primarily by using composite straight-line rates, which approximated 3.5% in 2012, 3.9% in 2011, and 3.4% in 2010. Depreciation studies are conducted periodically to update the composite rates. When property subject to depreciation is retired or otherwise disposed of in the normal course of business, its original cost, together with the cost of removal, less salvage, is charged to accumulated depreciation. Minor items of property included in the original cost of the plant are retired when the related property unit is retired. Depreciation includes an amount for the expected cost of removal of facilities. In 2009, the Company filed a depreciation study as of December 31, 2008 with the Mississippi PSC and the FERC. The FERC accepted this study in 2009. In 2010, the Mississippi PSC issued an order approving the depreciation rates effective in 2010. This change did not have a material impact on the financial statements.

The Company, in compliance with FERC guidance, classified $81.4 million as a plant acquisition adjustment on the purchase of Plant Daniel Units 3 and 4. This includes $76.1 million recorded in conjunction with the premium on long-term debt and is being amortized over 10 years beginning October 2011. See "Purchase of the Plant Daniel Combined Cycle Generating Units" herein for additional information.

On January 11, 2012, the Mississippi PSC issued an order allowing the Company to defer in a regulatory asset the difference between the revenue requirement under the purchase option of Plant Daniel Units 3 and 4 and the revenue requirement assuming operating lease accounting treatment for the extended term. The regulatory asset will be deferred for a 10-year period ending October 2021. At the conclusion of the deferral period, the unamortized deferral balance will be amortized into rates over the remaining life of the units.

In 2007, the Mississippi PSC issued an order allowing the Company to defer certain reliability related maintenance costs beginning in 2007 and recover them evenly over a four-year period beginning in 2008. These costs related to maintenance that was needed as follow-up to emergency repairs that were made subsequent to Hurricane Katrina. At December 31, 2011, the Company had fully amortized these costs.

Asset Retirement Obligations and Other Costs of Removal

Asset retirement obligations (ARO) are computed as the present value of the ultimate costs for an asset's future retirement and are recorded in the period in which the liability is incurred. The costs are capitalized as part of the related long-lived asset and depreciated over the asset's useful life. The Company has received accounting guidance from the Mississippi PSC allowing the continued accrual of other future retirement costs for long-lived assets that the Company does not have a legal obligation to retire. Accordingly, the accumulated removal costs for these obligations are reflected in the balance sheets as a regulatory liability.

The Company has retirement obligations related to various landfill sites, ash ponds, underground storage tanks, deep injection wells, water wells, substation removal, mine reclamation, and asbestos removal. The Company also has identified retirement obligations related to certain transmission and distribution facilities, co-generation facilities, certain wireless communication towers, and certain structures authorized by the U.S. Army Corps of Engineers. However, liabilities for the removal of these assets have not been recorded because the range of time over which the Company may settle these obligations is unknown and cannot be reasonably estimated. The Company will continue to recognize in the statements of income allowed removal costs in accordance with its regulatory treatment. Any differences between costs recognized in accordance with accounting standards related to asset retirement and environmental obligations and those reflected in rates are recognized as either a regulatory asset or liability, as ordered by the Mississippi PSC, and are reflected in the balance sheets.

Details of the ARO included in the balance sheets are as follows:

	2012	2011
	(in thousands)	
Balance at beginning of year	$ **19,148**	$ 18,601
Liabilities incurred	**20,989**	137
Liabilities settled	**(282)**	(644)
Accretion	**1,874**	1,054
Cash flow revisions	**386**	—
Balance at end of year	$ **42,115**	$ 19,148

Allowance for Funds Used During Construction

In accordance with regulatory treatment, the Company records allowance for funds used during construction (AFUDC), which represents the estimated debt and equity costs of capital funds that are necessary to finance the construction of new regulated facilities. While cash is not realized currently from such allowance, AFUDC increases the revenue requirement over the service life of the plant through a higher rate base and higher depreciation. The equity component of AFUDC is not included in the calculation of taxable income. The average annual AFUDC rate was 7.04%, 7.06%, and 7.33% for the years ended December 31, 2012, 2011, and 2010, respectively. The AFUDC rate is applied to CWIP consistent with jurisdictional regulatory treatment. AFUDC, net of income taxes, as a percentage of net income after dividends on preferred stock was 57.05%, 31.60%, and 6.97% for 2012, 2011, and 2010, respectively.

Impairment of Long-Lived Assets and Intangibles

The Company evaluates long-lived assets for impairment when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. The determination of whether an impairment has occurred is based on either a specific regulatory disallowance or an estimate of undiscounted future cash flows attributable to the assets, as compared with the carrying value of the assets. If an impairment has occurred, the amount of the impairment recognized is determined by either the amount of regulatory disallowance or by estimating the fair value of the assets and recording a loss if the carrying value is greater than the fair value. For assets identified as held for sale, the carrying value is compared to the estimated fair value less the cost to sell in order to determine if an impairment loss is required. Until the assets are disposed of, their estimated fair value is re-evaluated when circumstances or events change.

Provision for Property Damage

The Company carries insurance for the cost of certain types of damage to generation plants and general property. However, the Company is self-insured for the cost of storm, fire, and other uninsured casualty damage to its property, including transmission and distribution facilities. As permitted by the Mississippi PSC and the FERC, the Company accrues for the cost of such damage through an annual expense accrual credited to regulatory liability accounts for the retail and wholesale jurisdictions. The cost of repairing actual damage resulting from such events that individually exceed $50,000 is charged to the reserve. In 2009, the Mississippi PSC approved the System Restoration Rider (SRR) stipulation between the Company and the Mississippi Public Utilities Staff (MPUS). In accordance with the stipulation, every three years the Mississippi PSC, MPUS, and the Company will agree on SRR revenue level(s) for the ensuing period, based on historical data, expected exposure, type and amount of insurance coverage, excluding insurance cost, and any other relevant information. The accrual amount and the reserve balance are determined based on the SRR revenue level(s). If a significant change in circumstances occurs, then the SRR revenue level can be adjusted more frequently if the Company and the MPUS or the Mississippi PSC deem the change appropriate. Each year the Company will set rates to collect the approved SRR revenues. The property damage reserve accrual will be the difference between the approved SRR revenues and the SRR revenue requirement, excluding any accrual to the reserve. In 2012, 2011, and 2010, the Company made retail accruals of $3.5 million, $3.8 million, and $3.1 million, respectively, per the annual SRR rate filings. In addition, SRR allows the Company to set up a regulatory asset, pending review, if the allowable actual retail property damage costs exceed the amount in the retail property damage reserve. See Note 3 under "Retail Regulatory Matters – System Restoration Rider" for additional information. The Company accrued $0.3 million annually in 2012, 2011 and in 2010 for the wholesale jurisdiction.

Cash and Cash Equivalents

For purposes of the financial statements, temporary cash investments are considered cash equivalents. Temporary cash investments are securities with original maturities of 90 days or less.

Materials and Supplies

Generally, materials and supplies include the average cost of transmission, distribution, and generating plant materials. Materials are charged to inventory when purchased and then expensed or capitalized to plant, as appropriate, at weighted average cost when installed.

Fuel Inventory

Fuel inventory includes the average cost of coal, natural gas, oil, transportation, and emissions allowances. Fuel is charged to inventory when purchased and then expensed, at weighted average cost, as used and recovered by the Company through fuel cost recovery rates. The retail rate is approved by the Mississippi PSC while the wholesale rates are filed with the FERC. Emissions allowances granted by the Environmental Protection Agency (EPA) are included in inventory at zero cost.

Financial Instruments

The Company uses derivative financial instruments to limit exposure to fluctuations in interest rates, the prices of certain fuel purchases, electricity purchases and sales, and occasionally foreign currency exchange rates. All derivative financial instruments are recognized as either assets or liabilities (included in "Other" or shown separately as "Risk Management Activities") and are measured at fair value. See Note 9 for additional information. Substantially all of the Company's bulk energy purchases and sales contracts that meet the definition of a derivative are excluded from the fair value accounting requirements because they qualify for the "normal" scope exception, and are accounted for under the accrual method. Fuel and interest rate derivative contracts qualify as cash flow hedges of anticipated transactions or are recoverable through the Mississippi PSC approved fuel hedging program as discussed below. This results in the deferral of related gains and losses in OCI or regulatory assets and liabilities, respectively, until the hedged transactions occur. Foreign currency exchange rate hedges are designated as fair value hedges.

Settled foreign currency exchange hedges are booked as CWIP. Any ineffectiveness arising from these would be recognized currently in net income; however, the Company has regulatory approval allowing it to defer any ineffectiveness arising from hedging program instruments relating to the Kemper IGCC to a regulatory asset. Other derivative contracts are marked to market through current period income and are recorded on a net basis in the statements of income. The amounts related to derivatives on the cash flow statement are classified in the same category as the items being hedged. See Note 10 for additional information.

The Company does not offset fair value amounts recognized for multiple derivative instruments executed with the same counterparty under a master netting arrangement. Additionally, the Company has no outstanding collateral repayment obligations or rights to reclaim collateral arising from derivative instruments recognized at December 31, 2012.

The Mississippi PSC has approved the Company's request to implement an ECM which, among other things, allows the Company to utilize financial instruments to hedge its fuel commitments. Changes in the fair value of these financial instruments are recorded as regulatory assets or liabilities. Amounts paid or received as a result of financial settlement of these instruments are classified as fuel expense and are included in the ECM factor applied to customer billings. The Company's jurisdictional wholesale customers have a similar ECM mechanism, which has been approved by the FERC.

The Company is exposed to losses related to financial instruments in the event of counterparties' nonperformance. The Company has established controls to determine and monitor the creditworthiness of counterparties in order to mitigate the Company's exposure to counterparty credit risk.

Comprehensive Income

The objective of comprehensive income is to report a measure of all changes in common stock equity of an enterprise that result from transactions and other economic events of the period other than transactions with owners. Comprehensive income consists of net income, changes in the fair value of qualifying cash flow hedges, certain changes in pension and other postretirement benefit plans, and reclassifications for amounts included in net income.

Variable Interest Entities

The primary beneficiary of a VIE is required to consolidate the VIE when it has both the power to direct the activities of the VIE that most significantly impact the VIE's economic performance and the obligation to absorb losses or the right to receive benefits from the VIE that could potentially be significant to the VIE.

The Company is required to provide financing for all costs associated with the mine development and operation under a contract with Liberty Fuels Company, LLC, a subsidiary of North American Coal Corporation (Liberty Fuels), in conjunction with the construction of the Kemper IGCC. Liberty Fuels qualifies as a VIE for which the Company is the primary beneficiary. For the year ended 2011, Liberty Fuels did not have a material impact on the financial position and results of operations of the Company. For the year ended December 31, 2012, the VIE consolidation resulted in an ARO and an associated liability in the amounts of $21.0 million and $21.8 million, respectively. See Note 3 under "Integrated Coal Gasification Combined Cycle" for additional information.

2. RETIREMENT BENEFITS

The Company has a defined benefit, trusteed, pension plan covering substantially all employees. This qualified pension plan is funded in accordance with requirements of the Employee Retirement Income Security Act of 1974, as amended (ERISA). In December 2012, the Company contributed $43.0 million to the qualified pension plan. No mandatory contributions to the qualified pension plan are anticipated for the year ending December 31, 2013. The Company also provides certain defined benefit pension plans for a selected group of management and highly compensated employees. Benefits under these non-qualified pension plans are funded on a cash basis. In addition, the Company provides certain medical care and life insurance benefits for retired employees through other postretirement benefit plans. The Company funds its other postretirement trusts to the extent required by the FERC. For the year ending December 31, 2013, other postretirement trust contributions are expected to be less than $1 million.

Actuarial Assumptions

The weighted average rates assumed in the actuarial calculations used to determine both the benefit obligations as of the measurement date and the net periodic costs for the pension and other postretirement benefit plans for the following year are presented below. Net periodic benefit costs were calculated in 2009 for the 2010 plan year using discount rates for the pension plans and the other postretirement benefit plans of 5.92% and 5.83%, respectively, and an annual salary increase of 4.18%.

	2012	2011	2010
Discount rate:			
Pension plans	**4.26%**	4.98%	5.51%
Other postretirement benefit plans	**4.04**	4.87	5.39
Annual salary increase	**3.59**	3.84	3.84
Long-term return on plan assets:			
Pension plans	**8.20**	8.45	8.45
Other postretirement benefit plans	**6.96**	7.53	7.65

The Company estimates the expected rate of return on pension plan and other postretirement benefit plan assets using a financial model to project the expected return on each current investment portfolio. The analysis projects an expected rate of return on each of seven different asset classes in order to arrive at the expected return on the entire portfolio relying on each trust's target asset allocation and reasonable capital market assumptions. The financial model is based on four key inputs: anticipated returns by asset class (based in part on historical returns), each trust's target asset allocation, an anticipated inflation rate, and the projected impact of a periodic rebalancing of each trust's portfolio.

An additional assumption used in measuring the accumulated other postretirement benefit obligations (APBO) is the weighted average medical care cost trend rate. The weighted average medical care cost trend rates used in measuring the APBO as of December 31, 2012 were as follows:

	Initial Cost Trend Rate	**Ultimate Cost Trend Rate**	**Year That Ultimate Rate Is Reached**
Pre-65	8.00%	5.00%	2020
Post-65 medical	6.00	5.00	2020
Post-65 prescription	6.00	5.00	2020

An annual increase or decrease in the assumed medical care cost trend rate of 1% would affect the APBO and the service and interest cost components at December 31, 2012 as follows:

	1 Percent Increase	**1 Percent Decrease**
	(in thousands)	
Benefit obligation	$ 6,000	$ (5,099)
Service and interest costs	316	(268)

Pension Plans

The total accumulated benefit obligation for the pension plans was $392 million at December 31, 2012 and $339 million at December 31, 2011. Changes in the projected benefit obligations and the fair value of plan assets during the plan years ended December 31, 2012 and 2011 were as follows:

	2012	2011
	(in thousands)	
Change in benefit obligation		
Benefit obligation at beginning of year	**$ 369,680**	$ 330,315
Service cost	**9,416**	8,838
Interest cost	**18,019**	17,827
Benefits paid	**(14,949)**	(14,587)
Plan amendments	**—**	—
Actuarial loss	**50,387**	27,287
Balance at end of year	**432,553**	369,680
Change in plan assets		
Fair value of plan assets at beginning of year	**282,100**	283,698
Actual return on plan assets	**39,668**	10,805
Employer contributions	**44,930**	2,184
Benefits paid	**(14,949)**	(14,587)
Fair value of plan assets at end of year	**351,749**	282,100
Accrued liability	**$ (80,804)**	$ (87,580)

At December 31, 2012, the projected benefit obligations for the qualified and non-qualified pension plans were $400 million and $32 million, respectively. All pension plan assets are related to the qualified pension plan.

Amounts recognized in the balance sheets at December 31, 2012 and 2011 related to the Company's pension plans consist of the following:

	2012	2011
	(in thousands)	
Other regulatory assets, deferred	**$ 146,838**	$ 117,354
Other current liabilities	**(2,087)**	(1,652)
Employee benefit obligations	**(78,717)**	(85,928)

Presented below are the amounts included in regulatory assets at December 31, 2012 and 2011 related to the defined benefit pension plans that had not yet been recognized in net periodic pension cost along with the estimated amortization of such amounts for 2013.

	2012	2011	Estimated Amortization in 2013
		(in thousands)	
Prior service cost	**$ 5,261**	$ 6,570	**$ 1,143**
Net (gain) loss	**141,577**	110,784	**9,461**
Other regulatory assets, deferred	**$ 146,838**	$ 117,354	

The changes in the balance of regulatory assets related to the defined benefit pension plans for the years ended December 31, 2012 and 2011 are presented in the following table:

	Regulatory Assets
	(in thousands)
Balance at December 31, 2010	$ 78,130
Net (gain) loss	41,647
Change in prior service costs	—
Reclassification adjustments:	
Amortization of prior service costs	(1,309)
Amortization of net gain (loss)	(1,114)
Total reclassification adjustments	(2,423)
Total change	39,224
Balance at December 31, 2011	$ 117,354
Net (gain) loss	**34,893**
Change in prior service costs	—
Reclassification adjustments:	
Amortization of prior service costs	**(1,309)**
Amortization of net gain (loss)	**(4,100)**
Total reclassification adjustments	**(5,409)**
Total change	**29,484**
Balance at December 31, 2012	**$ 146,838**

Components of net periodic pension cost were as follows:

	2012	2011	2010
		(in thousands)	
Service cost	**$ 9,416**	$ 8,838	$ 8,300
Interest cost	**18,019**	17,827	17,916
Expected return on plan assets	**(24,121)**	(25,166)	(21,451)
Recognized net (gain) loss	**4,100**	1,114	634
Net amortization	**1,309**	1,309	1,391
Net periodic pension cost	**$ 8,723**	$ 3,922	$ 6,790

Net periodic pension cost is the sum of service cost, interest cost, and other costs netted against the expected return on plan assets. The expected return on plan assets is determined by multiplying the expected rate of return on plan assets and the market-related value of plan assets. In determining the market-related value of plan assets, the Company has elected to amortize changes in the market value of all plan assets over five years rather than recognize the changes immediately. As a result, the accounting value of plan assets that is used to calculate the expected return on plan assets differs from the current fair value of the plan assets.

Future benefit payments reflect expected future service and are estimated based on assumptions used to measure the projected benefit obligation for the pension plans. At December 31, 2012, estimated benefit payments were as follows:

	Benefit Payments
	(in thousands)
2013	$ 16,282
2014	17,121
2015	17,947
2016	18,886
2017	20,001
2018 to 2022	117,471

Other Postretirement Benefits

Changes in the APBO and in the fair value of plan assets during the plan years ended December 31, 2012 and 2011 were as follows:

	2012	2011
	(in thousands)	
Change in benefit obligation		
Benefit obligation at beginning of year	$ **87,447**	$ 81,688
Service cost	**1,038**	1,012
Interest cost	**4,155**	4,292
Benefits paid	**(4,432)**	(4,094)
Actuarial loss	**3,166**	4,073
Plan amendments	**—**	—
Retiree drug subsidy	**409**	476
Balance at end of year	**91,783**	87,447
Change in plan assets		
Fair value of plan assets at beginning of year	**20,534**	20,955
Actual return on plan assets	**2,427**	720
Employer contributions	**3,052**	2,477
Benefits paid	**(4,023)**	(3,618)
Fair value of plan assets at end of year	**21,990**	20,534
Accrued liability	$ **(69,793)**	$ (66,913)

Amounts recognized in the balance sheets at December 31, 2012 and 2011 related to the Company's other postretirement benefit plans consist of the following:

	2012	2011
	(in thousands)	
Other regulatory assets, deferred	$ **15,454**	$ 13,324
Employee benefit obligations	**(69,793)**	(66,913)

Presented below are the amounts included in regulatory assets at December 31, 2012 and 2011 related to the other postretirement benefit plans that had not yet been recognized in net periodic other postretirement benefit cost along with the estimated amortization of such amounts for 2013.

	2012	2011	Estimated Amortization in 2013
		(in thousands)	
Prior service cost	**$ (2,498)**	$ (2,686)	**$ (188)**
Net (gain) loss	**17,952**	15,839	**659**
Transition obligation	**—**	171	**—**
Other regulatory assets, deferred	**$ 15,454**	$ 13,324	

The changes in the balance of regulatory assets related to the other postretirement benefit plans for the plan years ended December 31, 2012 and 2011 are presented in the following table:

	Regulatory Assets
	(in thousands)
Balance at December 31, 2010	$ 8,618
Net (gain) loss	4,980
Change in prior service costs/transition obligation	—
Reclassification adjustments:	
Amortization of transition obligation	(228)
Amortization of prior service costs	188
Amortization of net gain (loss)	(234)
Total reclassification adjustments	(274)
Total change	4,706
Balance at December 31, 2011	$ 13,324
Net (gain) loss	**2,600**
Change in prior service costs/transition obligation	**—**
Reclassification adjustments:	
Amortization of transition obligation	**(171)**
Amortization of prior service costs	**188**
Amortization of net gain (loss)	**(487)**
Total reclassification adjustments	**(470)**
Total change	**2,130**
Balance at December 31, 2012	**$ 15,454**

Components of the other postretirement benefit plans' net periodic cost were as follows:

	2012	2011	2010
		(in thousands)	
Service cost	**$ 1,038**	$ 1,012	$ 1,305
Interest cost	**4,155**	4,292	4,763
Expected return on plan assets	**(1,552)**	(1,763)	(1,826)
Net amortization	**470**	274	574
Net postretirement cost	**$ 4,111**	$ 3,815	$ 4,816

Future benefit payments, including prescription drug benefits, reflect expected future service and are estimated based on assumptions used to measure the APBO for the other postretirement benefit plans. Estimated benefit payments are reduced by drug subsidy receipts expected as a result of the Medicare Prescription Drug, Improvement, and Modernization Act of 2003 as follows:

	Benefit Payments	Subsidy Receipts	Total
		(in thousands)	
2013	$ 5,174	$ (601)	$ 4,573
2014	5,442	(663)	4,779
2015	5,754	(720)	5,034
2016	5,995	(782)	5,213
2017	6,280	(845)	5,435
2018 to 2022	33,822	(4,414)	29,408

Benefit Plan Assets

Pension plan and other postretirement benefit plan assets are managed and invested in accordance with all applicable requirements, including ERISA and the Internal Revenue Code of 1986, as amended (Internal Revenue Code). The Company's investment policies for both the pension plan and the other postretirement benefit plans cover a diversified mix of assets, including equity and fixed income securities, real estate, and private equity. Derivative instruments are used primarily to gain efficient exposure to the various asset classes and as hedging tools. The Company minimizes the risk of large losses primarily through diversification but also monitors and manages other aspects of risk.

The composition of the Company's pension plan and other postretirement benefit plan assets as of December 31, 2012 and 2011, along with the targeted mix of assets for each plan, is presented below:

	Target	2012	2011
Pension plan assets:			
Domestic equity	26%	**28%**	29%
International equity	25	**24**	25
Fixed income	23	**27**	23
Special situations	3	**1**	—
Real estate investments	14	**13**	14
Private equity	9	**7**	9
Total	100%	**100%**	100%
Other postretirement benefit plan assets:			
Domestic equity	21%	**22%**	22%
International equity	20	**19**	20
Fixed income	39	**42**	40
Special situations	2	**1**	—
Real estate investments	11	**10**	11
Private equity	7	**6**	7
Total	100%	**100%**	100%

The investment strategy for plan assets related to the Company's qualified pension plan is to be broadly diversified across major asset classes. The asset allocation is established after consideration of various factors that affect the assets and liabilities of the pension plan including, but not limited to, historical and expected returns, volatility, correlations of asset classes, the current level of assets and liabilities, and the assumed growth in assets and liabilities. Because a significant portion of the liability of the pension plan is long-term in nature, the assets are invested consistent with long-term investment expectations for return and risk. To manage the actual asset class exposures relative to the target asset allocation, the Company employs a formal rebalancing program. As additional risk management, external investment managers and service providers are subject to written guidelines to ensure appropriate and prudent investment practices.

Investment Strategies

Detailed below is a description of the investment strategies for each major asset category for the pension and other postretirement benefit plans disclosed above:

- ***Domestic equity.*** A mix of large and small capitalization stocks with generally an equal distribution of value and growth attributes, managed both actively and through passive index approaches.
- ***International equity.*** A mix of growth stocks and value stocks with both developed and emerging market exposure, managed both actively and through passive index approaches.
- ***Fixed income.*** A mix of domestic and international bonds.
- ***Special situations.*** Investments in opportunistic strategies with the objective of diversifying and enhancing returns and exploiting short-term inefficiencies as well as investments in promising new strategies of a longer-term nature.
- ***Real estate investments.*** Investments in traditional private market, equity-oriented investments in real properties (indirectly through pooled funds or partnerships) and in publicly traded real estate securities.
- ***Private equity.*** Investments in private partnerships that invest in private or public securities typically through privately-negotiated and/or structured transactions, including leveraged buyouts, venture capital, and distressed debt.

Benefit Plan Asset Fair Values

Following are the fair value measurements for the pension plan and the other postretirement benefit plan assets as of December 31, 2012 and 2011. The fair values presented are prepared in accordance with GAAP. For purposes of determining the fair value of the pension plan and other postretirement benefit plan assets and the appropriate level designation, management relies on information provided by the plan's trustee. This information is reviewed and evaluated by management with changes made to the trustee information as appropriate.

Valuation methods of the primary fair value measurements disclosed in the following tables are as follows:

- **Investments in equity securities:** Investments in equity securities such as common stocks, American depositary receipts, and real estate investment trusts that trade on a public exchange are classified as Level 1 investments and are valued at the closing price in the active market. Equity investments with unpublished prices (i.e. pooled funds) are valued as Level 2, when the underlying holdings used to value the investment are comprised of Level 1 or Level 2 equity securities.
- **Investments in fixed income securities:** Investments in fixed income securities are generally classified as Level 2 investments and are valued based on prices reported in the market place. Additionally, the value of fixed income securities takes into consideration certain items such as broker quotes, spreads, yield curves, interest rates, and discount rates that apply to the term of a specific instrument.
- **Investments in private equity and real estate:** Investments in private equity and real estate are generally classified as Level 3 as the underlying assets typically do not have observable inputs. The fund manager values the assets using various inputs and techniques depending on the nature of the underlying investments. In the case of private equity, techniques may include purchase multiples for comparable transactions, comparable public company trading multiples, and discounted cash flow analysis. Real estate managers generally use prevailing market capitalization rates, recent sales of comparable investments, and independent third-party appraisals to value underlying real estate investments. The fair value of partnerships is determined by aggregating the value of the underlying assets.

The fair values of pension plan assets as of December 31, 2012 and 2011 are presented below. These fair value measurements exclude cash, receivables related to investment income, pending investments sales, and payables related to pending investment purchases. Assets that are considered special situations investments, primarily real estate investments and private equities, are presented in the tables below based on the nature of the investment.

	Fair Value Measurements Using			
As of December 31, 2012:	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Total**
		(in thousands)		
Assets:				
Domestic equity*	$ 51,433	$ 29,624	$ —	$ 81,057
International equity*	40,337	43,303	—	83,640
Fixed income:				
U.S. Treasury, government, and agency bonds	—	22,820	—	22,820
Mortgage- and asset-backed securities	—	5,618	—	5,618
Corporate bonds	—	38,696	140	38,836
Pooled funds	—	17,656	—	17,656
Cash equivalents and other	209	24,251	—	24,460
Real estate investments	11,410	—	37,196	48,606
Private equity	—	—	26,240	26,240
Total	$ 103,389	$ 181,968	$ 63,576	$ 348,933

* Level 1 securities consist of actively traded stocks while Level 2 securities consist of pooled funds. Management believes that the portfolio is well-diversified with no significant concentrations of risk.

As of December 31, 2011:	Fair Value Measurements Using: Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
		(in thousands)		
Assets:				
Domestic equity*	$ 47,911	$ 22,115	$ —	$ 70,026
International equity*	49,250	14,111	—	63,361
Fixed income:				
U.S. Treasury, government, and agency bonds	—	17,960	—	17,960
Mortgage- and asset-backed securities	—	5,605	—	5,605
Corporate bonds	—	34,552	112	34,664
Pooled funds	—	15,757	—	15,757
Cash equivalents and other	28	5,773	—	5,801
Real estate investments	9,119	—	32,434	41,553
Private equity	—	—	24,151	24,151
Total	$ 106,308	$ 115,873	$ 56,697	$ 278,878

* Level 1 securities consist of actively traded stocks while Level 2 securities consist of pooled funds. Management believes that the portfolio is well-diversified with no significant concentrations of risk.

Changes in the fair value measurement of the Level 3 items in the pension plan assets valued using significant unobservable inputs for the years ended December 31, 2012 and 2011 were as follows:

	2012		2011	
	Real Estate Investments	Private Equity	Real Estate Investments	Private Equity
		(in thousands)		
Beginning balance	$ 32,434	$ 24,151	$ 27,976	$ 26,475
Actual return on investments:				
Related to investments held at year end	4,629	44	2,964	(498)
Related to investments sold during the year	133	3,415	830	1,951
Total return on investments	4,762	3,459	3,794	1,453
Purchases, sales, and settlements	—	(1,370)	664	(3,777)
Transfers into/out of Level 3	—	—	—	—
Ending balance	$ 37,196	$ 26,240	$ 32,434	$ 24,151

The fair values of other postretirement benefit plan assets as of December 31, 2012 and 2011 are presented below. These fair value measurements exclude cash, receivables related to investment income, pending investments sales, and payables related to pending investment purchases. Assets that are considered special situations investments, primarily real estate investments and private equities, are presented in the tables below based on the nature of the investment.

	Fair Value Measurements Using			
As of December 31, 2012:	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Total**
		(in thousands)		
Assets:				
Domestic equity*	$ 2,561	$ 1,475	$ —	$ 4,036
International equity*	2,008	2,156	—	4,164
Fixed income:				
U.S. Treasury, government, and agency bonds	—	5,187	—	5,187
Mortgage- and asset-backed securities	—	280	—	280
Corporate bonds	—	1,925	7	1,932
Pooled funds	—	879	—	879
Cash equivalents and other	11	1,612	—	1,623
Real estate investments	569	—	1,865	2,434
Private equity	—	14	1,293	1,307
Total	$ 5,149	$ 13,528	$ 3,165	$ 21,842

* Level 1 securities consist of actively traded stocks while Level 2 securities consist of pooled funds. Management believes that the portfolio is well-diversified with no significant concentrations of risk.

As of December 31, 2011:	Fair Value Measurements Using: Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
		(in thousands)		
Assets:				
Domestic equity*	$ 2,733	$ 1,260	$ —	$ 3,993
International equity*	2,807	804	—	3,611
Fixed income:				
U.S. Treasury, government, and agency bonds	—	4,796	—	4,796
Mortgage- and asset-backed securities	—	320	—	320
Corporate bonds	—	1,968	—	1,968
Pooled funds	—	898	—	898
Cash equivalents and other	1	987	—	988
Real estate investments	520	—	1,851	2,371
Private equity	—	—	1,377	1,377
Total	$ 6,061	$ 11,033	$ 3,228	$ 20,322

* Level 1 securities consist of actively traded stocks while Level 2 securities consist of pooled funds. Management believes that the portfolio is well-diversified with no significant concentrations of risk.

Changes in the fair value measurement of the Level 3 items in the other postretirement benefit plan assets valued using significant unobservable inputs for the years ended December 31, 2012 and 2011 were as follows:

	2012		2011	
	Real Estate Investments	Private Equity	Real Estate Investments	Private Equity
		(in thousands)		
Beginning balance	**$ 1,851**	**$ 1,377**	$ 1,625	$ 1,538
Actual return on investments:				
Related to investments held at year end	**119**	**(1)**	141	(29)
Related to investments sold during the year	**7**	**90**	47	85
Total return on investments	**126**	**89**	188	56
Purchases, sales, and settlements	**(112)**	**(173)**	38	(217)
Ending balance	**$ 1,865**	**$ 1,293**	$ 1,851	$ 1,377

Employee Savings Plan

The Company also sponsors a 401(k) defined contribution plan covering substantially all employees. The Company provides an 85% matching contribution on up to 6% of an employee's base salary. Total matching contributions made to the plan for 2012, 2011, and 2010 were $3.9 million, $3.8 million, and $3.8 million, respectively.

3. CONTINGENCIES AND REGULATORY MATTERS

General Litigation Matters

The Company is subject to certain claims and legal actions arising in the ordinary course of business. In addition, the Company's business activities are subject to extensive governmental regulation related to public health and the environment such as regulation of air emissions and water discharges. Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements such as air

quality and water standards, has increased generally throughout the U.S. In particular, personal injury, property damage, and other claims for damages alleged to have been caused by carbon dioxide (CO_2) and other emissions, coal combustion byproducts, and alleged exposure to hazardous materials, and/or requests for injunctive relief in connection with such matters, have become more frequent. The ultimate outcome of such pending or potential litigation against the Company cannot be predicted at this time; however, for current proceedings not specifically reported herein, management does not anticipate that the ultimate liabilities, if any, arising from such current proceedings would have a material effect on the Company's financial statements.

Environmental Matters

New Source Review Actions

In 1999, the EPA brought a civil action in the U.S. District Court for the Northern District of Georgia against certain Southern Company subsidiaries, including Alabama Power and Georgia Power, alleging that these subsidiaries had violated the New Source Review (NSR) provisions of the Clean Air Act and related state laws at certain coal-fired generating facilities. The EPA alleged NSR violations at five coal-fired generating facilities operated by Alabama Power, including a unit co-owned by the Company, and three coal-fired generating facilities operated by Georgia Power. The civil action sought penalties and injunctive relief, including an order requiring installation of the best available control technology at the affected units. These actions were filed concurrently with the issuance of notices of violation to the Company with respect to the Company's Plant Watson. The case against Georgia Power was administratively closed in 2001 and has not been reopened. After Alabama Power was dismissed from the original action, the EPA filed a separate action in 2001 against Alabama Power (including claims related to the unit co-owned by the Company) in the U.S. District Court for the Northern District of Alabama.

In 2006, the U.S. District Court for the Northern District of Alabama entered a consent decree, resolving claims relating to the alleged NSR violations at Plant Miller. In 2010, the EPA dismissed five of its eight remaining claims against Alabama Power, leaving only three claims, including one relating to the unit co-owned by the Company. In March 2011, the U.S. District Court for the Northern District of Alabama granted Alabama Power summary judgment on all remaining claims and dismissed the case with prejudice. That judgment is on appeal to the U.S. Court of Appeals for the Eleventh Circuit. On February 23, 2012, the EPA filed a motion in the U.S. District Court for the Northern District of Alabama seeking vacatur of the judgment and recusal of the judge in the case involving Alabama Power.

The Company believes it complied with applicable laws and regulations in effect at the time the work in question took place. The Clean Air Act authorizes maximum civil penalties of $25,000 to $37,500 per day, per violation, depending on the date of the alleged violation. An adverse outcome could require substantial capital expenditures that cannot be determined at this time and could possibly require payment of substantial penalties. Such expenditures could affect future results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates. The ultimate outcome of this matter cannot be determined at this time.

Climate Change Litigation

Kivalina Case

In 2008, the Native Village of Kivalina and the City of Kivalina filed a lawsuit in the U.S. District Court for the Northern District of California against several electric utilities (including Southern Company), several oil companies, and a coal company. The plaintiffs allege that the village is being destroyed by erosion allegedly caused by global warming that the plaintiffs attribute to emissions of greenhouse gases by the defendants. The plaintiffs assert claims for public and private nuisance and contend that some of the defendants (including Southern Company) acted in concert and are therefore jointly and severally liable for the plaintiffs' damages. The suit seeks damages for lost property values and for the cost of relocating the village, which is alleged to be $95 million to $400 million. In 2009, the U.S. District Court for the Northern District of California granted the defendants' motions to dismiss the case. On September 21, 2012, the U.S. Court of Appeals for the Ninth Circuit upheld the U.S. District Court for the Northern District of California's dismissal of the case. On November 27, 2012, the U.S. Court of Appeals for the Ninth Circuit denied the plaintiffs' request for review of the decision. On February 25, 2013, the plaintiffs filed a petition for writ of certiorari with the U.S. Supreme Court. Southern Company believes that these claims are without merit. While Southern Company believes the likelihood of loss is remote based on existing case law, it is not possible to predict with certainty whether the Company will incur any liability in connection with this matter. The ultimate outcome of this matter cannot be determined at this time.

Environmental Remediation

The Company must comply with environmental laws and regulations that cover the handling and disposal of waste and releases of hazardous substances. Under these various laws and regulations, the Company may also incur substantial costs to clean up properties. The Company has authority from the Mississippi PSC to recover approved environmental compliance costs through regulatory mechanisms.

In 2003, the Texas Commission on Environmental Quality (TCEQ) designated the Company as a potentially responsible party at a site in Texas. The site was owned by an electric transformer company that handled the Company's transformers as well as those of many other entities. The site owner is bankrupt and the State of Texas has entered into an agreement with the Company and several other utilities to investigate and remediate the site. The feasibility study/presumptive remedy document was originally filed with TCEQ in June 2011 and remains under consideration by the agency. Amounts expensed and accrued during 2010, 2011, and 2012 related to this work were not material. Hundreds of entities have received notices from the TCEQ requesting their participation in the anticipated site remediation. The final impact of this matter on the Company will depend upon further environmental assessment and the ultimate number of potentially responsible parties. The remediation expenses incurred by the Company are expected to be recovered through the Environmental Compliance Overview (ECO) Plan.

The final outcome of this matter cannot now be determined. However, based on the currently known conditions at this site and the nature and extent of activities relating to this site, the Company does not believe that additional liabilities, if any, at this site would be material to the financial statements.

FERC Matters

In November 2011, the Company filed a request with the FERC for an increase in wholesale base revenues of approximately $32 million under the wholesale cost-based electric tariff. In its filing with the FERC, the Company sought (i) approval to establish a regulatory asset for the portion of non-capitalizable Kemper IGCC-related costs which have been and will continue to be incurred during the construction period for the Kemper IGCC, (ii) authorization to defer as a regulatory asset, for the 10-year period ending October 2021, the difference between the revenue requirement under the purchase option of Plant Daniel Units 3 and 4 (assuming a remaining 30-year life) and the revenue requirement assuming the continuation of the operating lease regulatory treatment with the accumulated deferred balance at the end of the deferral being amortized into wholesale rates over the remaining life of Plant Daniel Units 3 and 4, and (iii) authority to defer in a regulatory asset costs related to the retirement or partial retirement of generating units as a result of environmental compliance rules.

On March 9, 2012, the Company entered into a settlement agreement with its wholesale customers with respect to the Company's request for revised rates under the wholesale cost-based electric tariff. The settlement agreement provides that base rates under the cost-based electric tariff will increase by approximately $22.6 million over a 12-month period with revised rates effective April 1, 2012. A significant portion of the difference between the requested base rate increase and the agreed upon rate increase is due to a change in the CWIP recovery on the Kemper IGCC. Under the settlement agreement, a portion of CWIP will continue to accrue AFUDC. The tariff customers specifically agreed to the same regulatory treatment for tariff ratemaking as the treatment approved for retail ratemaking by the Mississippi PSC with respect to (i) the accounting for Kemper IGCC-related costs that cannot be capitalized, (ii) the accounting for the lease termination and purchase of Plant Daniel Units 3 and 4, and (iii) the establishment of a regulatory asset for certain potential plant retirement costs.

On March 28, 2012, the FERC approved a motion to place interim rates into effect beginning in May 2012. On September 27, 2012, the Company, with its wholesale customers, filed a final settlement agreement with the FERC. On November 5, 2012, the settlement judge certified the settlement agreement to the FERC with the recommendation that it be approved. The FERC has not yet approved the settlement agreement. The ultimate outcome of this matter cannot be determined at this time.

Retail Regulatory Matters

Performance Evaluation Plan

The Company's retail base rates are set under the Performance Evaluation Plan (PEP), a rate plan approved by the Mississippi PSC. PEP was designed with the objective to reduce the impact of rate changes on the customer and provide incentives for the Company to keep customer prices low and customer satisfaction and reliability high. PEP is a mechanism for rate adjustments based on three indicators: price, customer satisfaction, and service reliability.

In the 2004 order establishing the Company's forward-looking PEP, the Mississippi PSC ordered that the MPUS and the Company review the operations of the PEP in 2007. By mutual agreement, this review was deferred until 2008 and continued into 2009. In 2009, concurrent with this review, the annual PEP evaluation filing for 2009 was suspended and the MPUS and the Company filed a joint report with the Mississippi PSC proposing several changes to the PEP. The Mississippi PSC approved the revised PEP in 2009, which resulted in a lower performance incentive under the PEP and therefore smaller and/or less frequent rate changes in the future. Later that year, the Company resumed annual evaluations and filed its annual PEP filing for 2010 under the revised PEP, which resulted in a lower allowed return on investment but no rate change.

In 2010, the Company filed its annual PEP filing for 2011 under the revised PEP, which indicated a rate increase of 1.936%, or $16.1 million, annually. In January 2011, the MPUS contested the filing. In June 2011, the Mississippi PSC issued an order approving a joint stipulation between the MPUS and the Company resulting in no change in rates.

In November 2011, the Company filed its annual PEP filing for 2012, which indicated a rate increase of 1.893%, or $17.4 million, annually. On January 10, 2012, the MPUS contested the filing.

In March 2011, the Company submitted its annual PEP lookback filing for 2010, which recommended no surcharge or refund. In May 2011, the Company received a letter from the MPUS disputing certain items in the 2010 PEP lookback filing. On April 2, 2012, the Company filed a motion to suspend the PEP lookback filing for 2011. Unresolved matters related to certain costs included in the 2010 PEP lookback filing also impact the 2011 PEP lookback filing, making it impractical to determine the Company's actual retail return on investment for 2011 for purposes of the 2011 PEP lookback filing. An order granting the suspension of the 2011 PEP lookback was signed by the Mississippi PSC on May 8, 2012. On or before March 15, 2013, the Company will submit its annual PEP lookback filing for 2012. While the Company does not expect the resolution of these unresolved matters to have a material impact on its financial statements, the ultimate outcome of these matters cannot be determined at this time.

On January 18, 2013, the Company filed its annual PEP filing for 2013, which indicated a rate increase of 1.990%, or $15.8 million, annually.

The ultimate outcome of these matters cannot be determined at this time.

Environmental Compliance Overview Plan

In November 2011, the Company filed a request to establish a regulatory asset to defer certain plant retirement costs if such costs are incurred. This request was made to minimize the potential rate impact to customers arising from pending and final environmental regulations which may require the premature retirement of some generating units. These environmental rules and regulations are continuously being monitored by the Company and all options are being evaluated. In December 2011, an order was issued by the Mississippi PSC authorizing the Company to defer all plant retirement related costs resulting from compliance with environmental regulations as a regulatory asset for future recovery.

On February 14, 2012, the Company submitted its 2012 ECO Plan filing which proposed a 0.3% increase in annual revenues for the Company. In compliance with the certificate of public convenience and necessity (CPCN) to construct a scrubber on Plant Daniel Units 1 and 2, the Company revised the 2012 ECO Plan filing to exclude scrubber expenditures from rate base, which resulted in a 0.16% decrease in annual revenues. On June 22, 2012, the 2012 ECO Plan filing, including the proposed rate decrease, was approved by the Mississippi PSC, effective on June 29, 2012.

On April 3, 2012, the Mississippi PSC approved the Company's request for a CPCN to construct a scrubber on Plant Daniel Units 1 and 2. On May 3, 2012, the Sierra Club filed a notice of appeal of the order with the Chancery Court of Harrison County, Mississippi (Chancery Court). These units are jointly owned by the Company and Gulf Power, with 50% ownership each. The estimated total cost of the project is approximately $660 million, with the Company's portion being $330 million, excluding AFUDC. The project is scheduled for completion in December 2015. The Company's portion of the cost is expected to be recovered through the ECO Plan. As of December 31, 2012, total project expenditures were $146.6 million, with the Company's portion being $73.3 million.

On February 12, 2013, the Company submitted its 2013 ECO Plan filing, which proposed no change in rates.

The ultimate outcome of these matters cannot be determined at this time.

Certificated New Plant

See "Integrated Coal Gasification Combined Cycle" for information on certificated new plant and the Company's cost recovery plans.

Fuel Cost Recovery

The Company establishes, annually, a retail fuel cost recovery factor that is approved by the Mississippi PSC. On January 18, 2013, in compliance with the Company's filing requirement, the Company requested an annual adjustment of the retail fuel cost recovery factor in an amount equal to a decrease of 4.7% of total 2012 retail revenue. At December 31, 2012, the amount of over recovered retail fuel costs included in the balance sheets was $56.6 million compared to $42.4 million at December 31, 2011. The Company also has a wholesale Municipal and Rural Associations (MRA) and a Market Based (MB) fuel cost recovery factor. Effective January 1, 2013, the wholesale MRA fuel rate decreased resulting in an annual decrease in an amount equal to 3.3% of total 2012 MRA revenue. Effective February 1, 2013, the wholesale MB fuel rate decreased, resulting in an annual decrease in an amount equal to 5.5% of total 2012 MB revenue. At December 31, 2012, the amount of over recovered wholesale MRA and MB fuel costs included in the balance sheets was $19.0 million and $2.1 million compared to $14.3 million and $2.2 million, respectively, at December 31, 2011. In addition, at December 31, 2012, the amount of over recovered MRA emissions allowance cost included in the balance sheets was $0.4 million compared to $1.7 million at December 31, 2011. The Company's operating revenues are adjusted for differences in actual recoverable fuel cost and amounts billed in accordance with the currently approved cost recovery rate. Accordingly, changes in the billing factor have no significant effect on the Company's revenues or net income, but will affect annual cash flow.

In March 2011, a portion of the Company's territorial wholesale loads that was formerly served under the MB tariff terminated service. Beginning in April 2011, a new power purchase agreement (PPA) went into effect to cover these MB customers as non-territorial load. In June 2011, the Company and South Mississippi Electric Power Association (SMEPA) reached an agreement to allocate $3.7 million of the over recovered fuel balance at March 31, 2011 to the PPA. This amount was subsequently refunded to SMEPA in June 2011.

The Mississippi PSC engaged an independent professional audit firm to conduct an audit of the Company's fuel-related expenditures included in the retail fuel adjustment clause and ECM. The 2012 audit of fuel-related expenditures began in the second quarter 2012 and was completed in the fourth quarter 2012 with no audit findings.

System Restoration Rider

The Company is required to make annual SRR filings to review charges to the property damage reserve and to determine the revenue requirement associated with property damage. The purpose of the SRR is to provide for recovery of costs associated with property damage (including certain property insurance and the costs of self insurance) and to facilitate the Mississippi PSC's review of these costs. The Mississippi PSC periodically agrees on SRR revenue levels that are developed based on historical data, expected exposure, type and amount of insurance coverage excluding insurance costs, and other relevant information. The applicable SRR rate level will be adjusted every three years, unless a significant change in circumstances occurs such that the Company and the MPUS or the Mississippi PSC deems that a more frequent change would be appropriate. The Company will submit annual filings setting forth SRR-related revenues, expenses, and investment for the projected filing period, as well as the true-up for the prior period.

In January 2011, the Company submitted its 2011 SRR rate filing with the Mississippi PSC, which proposed that the 2011 SRR rate level remain at zero and the Company be allowed to accrue $3.6 million to the property damage reserve in 2011. On May 5, 2011, the filing was approved by the Mississippi PSC. On February 2, 2012, the Company submitted its 2012 SRR rate filing with the Mississippi PSC, which proposed that the 2012 SRR rate level remain at zero and the Company be allowed to accrue $3.8 million to the property damage reserve in 2012. On April 3, 2012, the filing was approved by the Mississippi PSC. On February 1, 2013, the Company submitted its 2013 SRR rate filing with the Mississippi PSC, which proposed that the 2013 SRR rate level remain at zero and the Company be allowed to accrue $3.2 million to the property damage reserve in 2013. The ultimate outcome of this matter cannot be determined at this time.

Storm Damage Cost Recovery

In August 2012, Hurricane Isaac hit the Gulf Coast of the United States and caused damage within the Company's service area. The estimated total storm restoration costs relating to Hurricane Isaac through December 31, 2012 were $10.5 million. The Company maintains a reserve to cover the cost of damage from major storms to its transmission and distribution facilities and generally the cost of uninsured damage to its generation facilities and other property. At December 31, 2012, the balance in the storm reserve was $58.8 million.

Integrated Coal Gasification Combined Cycle

General

The Company is constructing the Kemper IGCC which will utilize an IGCC technology with an output capacity of 582 MWs. The Kemper IGCC will use as fuel locally mined lignite (an abundant, lower heating value coal) from a mine owned by the Company and situated adjacent to the Kemper IGCC. In connection with the Kemper IGCC, the Company also plans to construct and operate approximately 61 miles of CO_2 pipeline infrastructure. The Kemper IGCC is scheduled to be placed in-service in May 2014.

In 2010, the Mississippi PSC issued a CPCN authorizing the acquisition, construction, and operation of the Kemper IGCC (2010 MPSC Order). The Sierra Club filed an appeal of the Mississippi PSC's issuance of the CPCN and, on March 15, 2012, the Mississippi Supreme Court reversed the decision of the Chancery Court of Harrison County, Mississippi (Chancery Court) upholding the 2010 MPSC Order and remanded the matter to the Mississippi PSC. The Mississippi Supreme Court concluded that the 2010 MPSC Order did not cite in sufficient detail substantial evidence upon which the Mississippi Supreme Court could determine the basis for the findings of the Mississippi PSC granting the CPCN. On March 30, 2012, the Mississippi PSC issued a temporary authorization which allowed the Company to continue construction and, on April 24, 2012, issued a detailed order (2012 MPSC Order) confirming the CPCN for the Kemper IGCC. On April 26, 2012, the Sierra Club appealed the 2012 MPSC Order to the Chancery Court. On December 17, 2012, the Chancery Court affirmed the 2012 MPSC Order which confirmed the issuance of the CPCN for the Kemper IGCC. On January 8, 2013, the Sierra Club filed an appeal of the Chancery Court's ruling with the Mississippi Supreme Court.

The certificated cost estimate of the Kemper IGCC included in the 2012 MPSC Order was $2.4 billion, net of $245.3 million of grants awarded to the project by the DOE under the CCPI2 and excluding the cost of the lignite mine and equipment, the cost of the CO_2 pipeline facilities, and financing costs related to the Kemper IGCC. The 2012 MPSC Order approved a construction cost cap of up to $2.88 billion, with recovery of prudently-incurred costs subject to approval by the Mississippi PSC. Exemptions from the cost cap included in the 2012 MPSC Order included the cost of the lignite mine and equipment, the cost of the CO_2 pipeline facilities, financing costs, and certain general exceptions, including change of law, force majeure, and beneficial capital (which exists when the Company demonstrates that the purpose and effect of the construction cost increase is to produce efficiencies that will result in a neutral or favorable effect on the ratepayers, relative to the original proposal for the CPCN).

The Company's current cost estimate for the Kemper IGCC (net of the $245.3 million CCPI2 grant, and excluding the cost of the lignite mine and equipment, the cost of the CO_2 pipeline facilities, financing costs, and certain general exceptions as contemplated in the 2012 MPSC Order and the settlement agreement between the Company and the Mississippi PSC entered into on January 24, 2013 (Settlement Agreement) that must be specifically approved by the Mississippi PSC) is approximately $2.88 billion. The Mississippi PSC and the MPUS have engaged their independent monitors to assess the current cost estimates and schedule projections for the Kemper IGCC. These consultants have issued reports with their own opinions as to the likelihood that costs for the Kemper IGCC will remain at or under the $2.88 billion cost cap and as to the expected in-service date. While the Company continues to believe its cost estimate and schedule projection remain appropriate based on the current status of the project, it is possible that the Company could experience further cost increases and/or schedule delays with respect to the Kemper IGCC. Certain factors have caused and may continue to cause the costs for the Kemper IGCC to increase and/or schedule delays to occur including, but not limited to, costs and productivity of labor, adverse weather conditions, shortages and inconsistent quality of equipment, materials and labor, contractor or supplier delay or non-performance under construction or other agreements, and unforeseen engineering problems. To the extent it becomes probable that costs beyond any permitted exceptions to the cost cap will exceed $2.88 billion or it becomes probable that the Mississippi PSC will disallow a portion of the costs relating to the Kemper IGCC, including certain general exceptions as contemplated in the 2012 MPSC Order and the Settlement Agreement, charges to expense may occur and these charges could be material. See "Cost Recovery Plans" below for additional information relating to the Settlement Agreement that defines the process for resolving matters regarding cost recovery related to the Kemper IGCC.

As of December 31, 2012, the Company had spent a total of $2.51 billion on the Kemper IGCC, including the cost of the lignite mine and equipment, the cost of the CO_2 pipeline facilities, and other deferred costs. Of this total, $2.47 billion was included in CWIP (which is net of $245.3 million of CCPI2 grant funds), $34.9 million was recorded in other regulatory assets, $3.8 million was recorded in other deferred charges and assets, and $1.0 million was previously expensed. Consistent with the treatment of non-capital costs incurred during the pre-construction period, the Mississippi PSC granted the Company the authority to defer all non-capital Kemper IGCC-related costs to a regulatory asset during the construction period. This includes deferred costs associated with the generation resource planning, evaluation, and screening activities. The amortization period for the regulatory asset will be determined by the Mississippi PSC at a later date.

In addition, the Company is authorized to accrue carrying costs on the unamortized balance of such regulatory assets at a rate and in a manner to be determined by the Mississippi PSC in future cost recovery mechanism proceedings.

The 2012 MPSC Order established periodic prudence reviews during the annual CWIP review process. Of the total costs of $51 million incurred through March 2009, $46 million has been reviewed and deemed prudent by the Mississippi PSC. Due to the decision of the Mississippi PSC to deny the Certificated New Plant-A (CNP-A) rate filing and a 2012 rate request related to the Kemper IGCC described below, prudence reviews for the construction costs of the Kemper IGCC incurred after March 2009 have not been made. The Settlement Agreement provides for completion of all prudence reviews within six months of the date the Kemper IGCC is placed in service. See "Cost Recovery Plans" herein for additional information.

The ultimate outcome of these matters, including the determinations of prudency and the specific manner of recovery of prudently-incurred costs relating to the Kemper IGCC, is subject to further regulatory actions and cannot be determined at this time.

Cost Recovery Plans

The 2012 MPSC Order included provisions relating to both the Company's recovery of financing costs during the course of construction of the Kemper IGCC and the Company's recovery of costs following the date the Kemper IGCC is placed in service. In the 2012 MPSC Order, the Mississippi PSC approved financing cost recovery on CWIP balances not to exceed the $2.4 billion certificated cost estimate for the Kemper IGCC. The 2012 MPSC Order provided for the accrual of AFUDC in 2010 and 2011 and for the current recovery of financing costs on 100% of CWIP in 2012, 2013, and through May 1, 2014 (provided that the amount of financing cost recovery allowed is to be reduced by the amount of certain state and federal government construction cost incentives received by the Company and must be justified by a showing that such recovery will benefit customers over the life of the Kemper IGCC). With respect to recovery of costs following the in-service date of the Kemper IGCC, the 2012 MPSC Order provided for the establishment of operational cost and revenue parameters based upon assumptions in the Company's petition for the CPCN.

On June 1, 2012, the MPUS signed a joint stipulation with the Company to establish a proposed rate schedule detailing CNP-A and, on June 14, 2012, the Company submitted to the Mississippi PSC a filing to establish the new CNP-A rate schedule and a stipulated rate increase based upon the revenue request of between $55.3 million and $58.6 million to recover financing costs over the remainder of 2012. On June 22, 2012, the Mississippi PSC denied the proposed CNP-A rate schedule and the 2012 rate recovery filings submitted by the Company, pending a final ruling from the Mississippi Supreme Court regarding the Sierra Club's appeal of the Mississippi PSC's issuance of the CPCN for the Kemper IGCC.

On July 9, 2012, the Company appealed the Mississippi PSC's June 22, 2012 decision to the Mississippi Supreme Court and requested interim rates under bond of $55.3 million. On July 31, 2012, the Mississippi Supreme Court denied the Company's request for interim rates under bond until the Mississippi Supreme Court decides the Company's appeal of the Mississippi PSC's June 22, 2012 decision.

On January 24, 2013, the Company and the Mississippi PSC entered into the Settlement Agreement that (1) establishes the process for resolving matters regarding cost recovery related to the Kemper IGCC for the purpose of mitigating risks to the Company and its customers and expediting the regulatory process associated with future rate filings required under the Settlement Agreement and (2) resolves the Company's CNP-A rate appeal before the Mississippi Supreme Court.

On February 12, 2013, the Mississippi Supreme Court granted the Company and the Mississippi PSC's joint filing for dismissal of the Company's appeal of the Mississippi PSC's June 22, 2012 decision.

Under the terms of the Settlement Agreement, the Company and the Mississippi PSC will follow certain agreed-upon regulatory procedures and schedules for resolving the cost recovery matters related to the Kemper IGCC. These procedures and schedules include the following: (1) the Company's filing within 30 days of the Settlement Agreement of a new request to increase rates in 2013 in an amount not to exceed a $172 million annual revenue requirement, based upon projected investment as of December 31, 2013, to be recorded to a regulatory liability to be used to mitigate rate impacts when the Kemper IGCC is placed in service (which filing for $172 million was made on January 25, 2013); (2) the Mississippi PSC's decision on that matter within 50 days of the Company's request; (3) the Company's collaboration with the MPUS to file with the Mississippi PSC within three months of the Settlement Agreement a rate recovery plan for the Kemper IGCC for the first seven years of its operation, along with a proposed revenue requirement under such plan for 2014 through 2020 (which filing was made on February 26, 2013 as described below); (4) the Mississippi PSC's decision on the rate recovery plan within four months of that filing; (5) the Company's agreement to limit the portion of prudently-incurred Kemper IGCC costs to be included in rate base to the $2.4 billion certificated cost estimate, plus costs related to the lignite mine and CO_2 pipeline as well as any other costs permitted or determined to be excluded from the cost cap, provided that this limitation will not prevent the Company from securing alternate financing to recover any prudently-incurred Kemper IGCC costs, including financing costs and plant costs above the $2.4 billion certificated

cost estimate, not otherwise recovered in any Mississippi PSC rate proceeding contemplated by the Settlement Agreement; and (6) the Mississippi PSC's completion of its prudence review of the Kemper IGCC costs incurred through 2012 within six months of the Settlement Agreement, an additional prudence review upon considering the seven-year rate plan for costs incurred through the most recent reporting period, and a final prudence review of the remaining project costs within six months of the Kemper IGCC's in-service date.

Legislation to authorize a multi-year rate plan and legislation to provide for alternate financing through securitization was passed in the Mississippi legislature and was signed by the Governor on February 26, 2013. The Company contemplates using securitization as provided in the legislation as its form of alternate financing for prudently-incurred Kemper IGCC costs, including financing costs and plant costs above the $2.4 billion certificated cost estimate, not otherwise recovered in any Mississippi PSC rate proceeding contemplated by the Settlement Agreement.

On February 26, 2013, the Company, in compliance with the Settlement Agreement, filed with the Mississippi PSC a rate recovery plan for the Kemper IGCC for 2014 through 2020, the first seven years of operation of the Kemper IGCC. The rate recovery plan proposes recovery of an annual revenue requirement of approximately $150 million of Kemper IGCC-related operational costs and rate base amounts, including plant costs equal to the $2.4 billion certificated cost estimate. Approval of the Company's request to increase rates in 2013 to mitigate the rate impacts of the Kemper IGCC filed on January 25, 2013 is integral to the rate recovery plan as the proposed filing contemplates amortization of the regulatory liability to be used to mitigate rate impacts from 2014 through 2020, based on a fixed amortization schedule that requires approval by the Mississippi PSC. Under the rate recovery plan filing, the Company proposes annual recovery to remain the same from 2014 through 2020 and while it is the intent of the Company for the actual revenue requirement to equal the proposed revenue requirement for certain items, the Company proposes that the annual differences for those items through 2020 will be deferred, subject to accrual of carrying costs, and the cumulative balance will be reviewed at the end of the term of the Settlement Agreement by the Mississippi PSC for determination of the manner of recovery. The Company proposes to secure recovery of prudently-incurred Kemper IGCC costs, including financing costs and plant costs above the $2.4 billion certificated cost estimate, not otherwise recovered in any Mississippi PSC rate proceeding contemplated by the Settlement Agreement to be provided for with alternate financing through securitization. The rate recovery necessary to recover the annual costs of securitization is proposed to be filed and begin after the Kemper IGCC is placed in service.

Under the terms of the Settlement Agreement, the Company has the right to terminate the Settlement Agreement if certain conditions, including the passage of multi-year rate plan legislation that is contemplated under the Settlement Agreement, are not met, if the Company is unable to secure alternate financing for any prudently-incurred Kemper IGCC costs not otherwise recovered in any Mississippi PSC rate proceeding contemplated by the Settlement Agreement, or if the Mississippi PSC fails to comply with the requirements of the Settlement Agreement.

The ultimate outcome of these matters, including the determinations of prudency and the specific manner of recovery of prudently-incurred costs relating to the Kemper IGCC, is subject to further regulatory actions and cannot be determined at this time.

Tax Incentives

The Internal Revenue Service (IRS) has allocated $133 million (Phase I) and $279 million (Phase II) of Internal Revenue Code Section 48A tax credits to the Company in connection with the Kemper IGCC. The Company's utilization of Phase I and Phase II credits is dependent upon meeting the IRS certification requirements, including an in-service date no later than May 11, 2014 for the Phase I credits and April 19, 2016 for the Phase II credits. In order to remain eligible for the Phase II credits, the Company plans to capture and sequester (via enhanced oil recovery) at least 65% of the CO_2 produced by the Kemper IGCC during operations in accordance with the rules for Section 48A investment tax credits. Through December 31, 2012, the Company received or accrued tax benefits totaling $361.6 million for these tax credits, which will be amortized as a reduction to depreciation and amortization over the life of the Kemper IGCC. As a result of bonus tax depreciation on certain assets placed, or to be placed, in service in 2012 and 2013, and the subsequent reduction in federal taxable income, the Company estimates that it will not be able to utilize $170.9 million of these tax credits until after 2013. IRS guidelines allow these unused tax credits to be carried forward for 20 years, expiring at the end of 2031, if not utilized before then. On October 15, 2012, the Company filed an application with the DOE for certification of the Kemper IGCC for additional tax credits under the Internal Revenue Code Section 48A (Phase III). A portion of the tax credits realized by the Company may be subject to recapture upon successful completion of SMEPA's purchase of an undivided interest in the Kemper IGCC as described below. In addition, all or a portion of the tax credits will be subject to recapture if the Company fails to satisfy the in-service date requirements and carbon capture requirements described above. See Note 5 under "Current and Deferred Income Taxes" for additional information.

On January 2, 2013, the American Taxpayer Relief Act of 2012 (ATRA) was signed into law. The ATRA retroactively extended several tax credits through 2013 and 50% bonus depreciation for property to be placed in service in 2013 (and for certain long-

term production-period projects to be placed in service in 2014), which is expected to apply to the Kemper IGCC.

The ultimate outcome of these matters cannot be determined at this time.

Lignite Mine and CO_2 Pipeline Facilities

In conjunction with the Kemper IGCC, the Company will own the lignite mine and equipment and has acquired and will continue to acquire mineral reserves located around the Kemper IGCC site in Kemper County. The mine is scheduled to be placed in-service in June 2013. The estimated capital cost of the mine is approximately $245 million, of which $163.3 million has been incurred through December 31, 2012.

In 2010, the Company executed a 40-year management fee contract with Liberty Fuels Company, LLC, a wholly-owned subsidiary of The North American Coal Corporation (Liberty Fuels), which will develop, construct, and manage the mining operations. Because Liberty Fuels conducts all of its activities on behalf of the Company, Liberty Fuels qualifies as a VIE for which the Company is the primary beneficiary. The contract with Liberty Fuels is effective through the end of the mine reclamation. As the mining permit holder, Liberty Fuels has a legal obligation to perform mine reclamation and the Company has a contractual obligation to fund all reclamation activities. Consistent with the requirements of consolidation accounting, Liberty Fuels is consolidated in the financial statements of the Company and accordingly the asset retirement cost and the ARO have been recorded in the Company's financial statements. In addition to the obligation to fund the reclamation activities, the Company currently provides working capital support to Liberty Fuels through cash advances for capital purchases, payroll, and other operating expenses.

In addition, the Company will acquire, construct, and operate the CO_2 pipeline for the planned transport of captured CO_2 for use in enhanced oil recovery. The Company has entered into agreements with Denbury Onshore (Denbury), a subsidiary of Denbury Resources Inc., and Treetop Midstream Services, LLC (Treetop), an affiliate of Tellus Operating Group, LLC and a subsidiary of Tengrys, LLC, pursuant to which Denbury will purchase 70% of the CO_2 captured from the Kemper IGCC and Treetop will purchase 30% of the CO_2 captured from the Kemper IGCC. The estimated capital cost of the CO_2 pipeline facilities is approximately $132 million, of which $78.4 million has been incurred through December 31, 2012.

The ultimate outcome of these matters, including the determinations of prudency and the specific manner of recovery of prudently-incurred costs relating to the Kemper IGCC, is subject to further regulatory actions and cannot be determined at this time.

Proposed Sale of Undivided Interest to SMEPA

In 2010, the Company and SMEPA entered into an asset purchase agreement whereby SMEPA agreed to purchase a 17.5% undivided interest in the Kemper IGCC. On February 28, 2012, the Mississippi PSC approved the sale and transfer of 17.5% of the Kemper IGCC to SMEPA. On June 29, 2012, the Company and SMEPA signed an amendment to the asset purchase agreement whereby SMEPA extended its option to purchase until December 31, 2012 and reduced its purchase commitment percentage from a 17.5% to a 15% undivided interest in the Kemper IGCC, subject to approval by the Mississippi PSC. On December 31, 2012, the Company and SMEPA agreed to extend SMEPA's option to purchase through December 31, 2013.

The closing of this transaction is conditioned upon execution of a joint ownership and operating agreement, receipt of all construction permits, appropriate regulatory approvals, financing, and other conditions. On September 27, 2012, SMEPA received a conditional loan commitment from Rural Utilities Service to provide funding for SMEPA's undivided interest in the Kemper IGCC.

On March 6, 2012, the Company received a $150 million interest-bearing refundable deposit from SMEPA to be applied to the purchase. While the expectation is that the amount will be applied to the purchase price at closing, the Company would be required to refund the deposit upon the termination of the asset purchase agreement, within 60 days of a request by SMEPA for a full or partial refund, or within 15 days at SMEPA's discretion in the event that the Company is assigned a senior unsecured credit rating of BBB+ or lower by Standard and Poor's Ratings Services, a division of The McGraw Hill Companies, Inc. (S&P) or Baa1 or lower by Moody's Investors Services, Inc. (Moody's) or ceases to be rated by either of these rating agencies. Given the interest-bearing nature of the deposit and SMEPA's ability to request a refund, the deposit has been presented as a current liability in the Company's balance sheet herein and as financing proceeds in the Company's statement of cash flows herein.

The ultimate outcome of these matters cannot be determined at this time.

Baseload Act

In the 2008 regular session of the Mississippi legislature, a bill was passed and signed by the Governor to enhance the Mississippi PSC's authority to facilitate development and construction of base load generation in the State of Mississippi (Baseload Act). The Baseload Act authorizes, but does not require, the Mississippi PSC to adopt a cost recovery mechanism that includes in retail base

rates, prior to and during construction, all or a portion of the prudently-incurred pre-construction and construction costs incurred by a utility in constructing a base load electric generating plant. Prior to the passage of the Baseload Act, such costs would traditionally be recovered only after the plant was placed in service. The Baseload Act also provides for periodic prudence reviews by the Mississippi PSC and prohibits the cancellation of any such generating plant without the approval of the Mississippi PSC. In the event of cancellation of the construction of the plant without approval of the Mississippi PSC, the Baseload Act authorizes the Mississippi PSC to make a public interest determination as to whether and to what extent the utility will be afforded rate recovery for costs incurred in connection with such cancelled generating plant. There are legal challenges to the constitutionality of the Baseload Act currently pending before the Mississippi Supreme Court. The ultimate impact of this legislation will depend on the outcome of any legal challenges and cannot be determined at this time. See "Cost Recovery Plans" herein for additional information regarding certain legislation related to the Kemper IGCC.

4. JOINT OWNERSHIP AGREEMENTS

The Company and Alabama Power own, as tenants in common, Units 1 and 2 (total capacity of 500 MWs) at Greene County Steam Plant, which is located in Alabama and operated by Alabama Power. Additionally, the Company and Gulf Power, own as tenants in common, Units 1 and 2 (total capacity of 1,000 MWs) at Plant Daniel, which is located in Mississippi and operated by the Company.

At December 31, 2012, the Company's percentage ownership and investment in these jointly-owned facilities in commercial operation were as follows:

Generating Plant	Percent Ownership	Plant in Service	Accumulated Depreciation	Construction Work in Progress
		(in thousands)		
Greene County				
Units 1 and 2	40%	$ 89,474	$ 45,402	$ 4,386
Daniel				
Units 1 and 2	50%	$ 293,451	$ 147,833	$ 73,534

The Company's proportionate share of plant operating expenses is included in the statements of income and the Company is responsible for providing its own financing.

See Note 3 under "Retail Regulatory Matters – Environmental Compliance Overview Plan" for additional information.

5. INCOME TAXES

On behalf of the Company, Southern Company files a consolidated federal income tax return and combined state income tax returns for the States of Alabama and Mississippi. Under a joint consolidated income tax allocation agreement, each subsidiary's current and deferred tax expense is computed on a stand-alone basis and no subsidiary is allocated more current expense than would be paid if it filed a separate income tax return. In accordance with IRS regulations, each company is jointly and severally liable for the federal tax liability.

Current and Deferred Income Taxes

Details of income tax provisions are as follows:

	2012	2011	2010
		(in thousands)	
Federal —			
Current	**$ 1,212**	$ (27,099)	$ 5,399
Deferred	**42,929**	65,206	35,367
	44,141	38,107	40,766
State —			
Current	**1,656**	(2,473)	3,319
Deferred	**4,594**	6,559	2,190
	6,250	4,086	5,509
Total	**$ 50,391**	$ 42,193	$ 46,275

The tax effects of temporary differences between the carrying amounts of assets and liabilities in the financial statements and their respective tax bases, which give rise to deferred tax assets and liabilities, are as follows:

	2012	2011
	(in thousands)	
Deferred tax liabilities —		
Accelerated depreciation	$ 385,899	$ 356,857
Property basis differences	72,451	48,268
Energy cost management clause under recovered	9,492	7,880
Regulatory assets associated with asset retirement obligations	16,851	7,557
Pensions and other benefits	33,756	18,283
Regulatory assets associated with employee benefit obligations	68,717	52,410
Regulatory assets associated with the Kemper IGCC	10,492	4,618
Long-term service agreement	—	5,231
Rate differential	27,270	8,400
Other	33,886	23,802
Total	658,814	533,306
Deferred tax assets —		
Federal effect of state deferred taxes	9,097	10,899
Fuel clause over recovered	38,955	30,050
Other property basis differences	980	2,918
Pension and other benefits	87,416	70,255
Property insurance	23,171	25,349
Premium on long-term debt	26,778	29,820
Unbilled fuel	11,642	14,951
Long-term service agreement	5,544	—
Asset retirement obligations	16,851	7,557
Interest rate hedges	5,644	5,763
Investment tax credit carryforward	170,938	77,400
Other	22,820	21,571
Total	419,836	296,533
Total deferred tax liabilities, net	238,978	236,773
Portion included in (accrued) prepaid income taxes, net	35,815	33,624
Accumulated deferred income taxes	$ 274,793	$ 270,397

At December 31, 2012, the tax-related regulatory assets were $73.0 million. These assets are primarily attributable to tax benefits that flowed through to customers in prior years, to deferred taxes previously recognized at rates lower than the current enacted tax law, and to taxes applicable to capitalized interest.

At December 31, 2012, the tax-related regulatory liabilities were $11.2 million. These liabilities are primarily attributable to deferred taxes previously recognized at rates higher than the current enacted tax law and to unamortized investment tax credits.

In accordance with regulatory requirements, deferred investment tax credits are amortized over the life of the related property with such amortization normally applied as a credit to reduce depreciation in the statements of income. Credits for non-Kemper IGCC related deferred investment tax credits amortized in this manner amounted to $1.2 million, $1.3 million, and $1.3 million for 2012, 2011, and 2010, respectively. At December 31, 2012, all non-Kemper IGCC investment tax credits available to reduce federal income taxes payable had been utilized.

In 2010, the Company began recognizing investment tax credits associated with the construction expenditures related to the Kemper IGCC. At December 31, 2012, the Company had $361.6 million in unamortized investment tax credits associated with the Kemper IGCC, which will be amortized over the life of the Kemper IGCC once placed in service. As a result of 100% bonus tax depreciation on certain assets placed, or to be placed, in service in 2012 and 2013, and the subsequent reduction in federal taxable income, the Company estimates that it will not be able to utilize $170.9 million of these tax credits until after 2013. IRS guidelines allow the resultant unused credits to be carried forward for 20 years expiring at the end of 2031, if not utilized before then.

In 2010, the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010 (Tax Relief Act) was signed into law. Major tax incentives in the Tax Relief Act include100% bonus depreciation for property placed in service after September 8, 2010 and through 2011 (and for certain long-term production-period projects placed in service in 2012) and 50% bonus depreciation for property placed in service in 2012 (and for certain long-term production-period projects to be placed in service in 2013).

Effective Tax Rate

A reconciliation of the federal statutory income tax rate to the effective income tax rate is as follows:

	2012	2011	2010
Federal statutory rate	**35.0%**	35.0%	35.0%
State income tax, net of federal deduction	**2.0**	1.9	2.8
Non-deductible book depreciation	**0.2**	0.3	0.3
Medicare subsidy	**(0.1)**	(0.1)	(0.2)
AFUDC-equity	**(11.3)**	(6.3)	(1.0)
Other	**(0.7)**	(0.2)	(0.8)
Effective income tax rate	**25.1%**	30.6%	36.1%

The Company's 2012 effective tax rate decreased from 2011 primarily due to the increase in non-taxable AFUDC equity related to increased construction expenditures.

Unrecognized Tax Benefits

For 2012, the total amount of unrecognized tax benefits increased by $0.8 million, resulting in a balance of $5.8 million as of December 31, 2012.

Changes during the year in unrecognized tax benefits were as follows:

	2012	2011	2010
		(in thousands)	
Unrecognized tax benefits at beginning of year	**$ 4,964**	$ 4,288	$ 3,026
Tax positions from current periods	**1,186**	1,486	868
Tax positions from prior periods	**(26)**	(810)	611
Reductions due to expired statute of limitations	**—**	—	(217)
Settlements with taxing authorities	**(369)**	—	—
Balance at end of year	**$ 5,755**	$ 4,964	$ 4,288

The change in tax positions from current periods for 2012 relates primarily to the tax accounting method change for repairs-generation assets and State of Mississippi tax credits. The tax positions decrease from prior periods for 2012 relates to the uncertain tax position for the tax accounting method change for repairs-transmission and distribution assets. See "Tax Method of Accounting for Repairs" below for additional information.

The impact on the Company's effective tax rate, if recognized, was as follows:

	2012	2011	2010
		(in thousands)	
Tax positions impacting the effective tax rate	$ 3,656	$ 4,144	$ 3,058
Tax positions not impacting the effective tax rate	2,099	820	1,230
Balance of unrecognized tax benefits	$ 5,755	$ 4,964	$ 4,288

The tax positions impacting the effective tax rate for 2012 primarily relate to the State of Mississippi Investment Tax Credit. The tax positions not impacting the effective tax rate for 2012 relate to the timing difference associated with the tax accounting method change for repairs - generation assets. See "Tax Method of Accounting for Repairs" herein for additional information. These amounts are presented on a gross basis without considering the related federal or state income tax impact.

Accrued interest for unrecognized tax benefits was as follows:

	2012	2011	2010
		(in thousands)	
Interest accrued at beginning of year	$ 680	$ 413	$ 230
Interest accrued during the year	92	267	183
Balance at end of year	$ 772	$ 680	$ 413

The Company classifies interest on tax uncertainties as interest expense. The Company did not accrue any penalties on uncertain tax positions.

It is reasonably possible that the amount of the unrecognized tax benefits associated with a majority of the Company's unrecognized tax positions will significantly increase or decrease within 12 months. The resolution of the tax accounting method change for repairs-generation assets, as well as the conclusion or settlement of state audits, could impact the balances significantly. At this time, an estimate of the range of reasonably possible outcomes cannot be determined.

The IRS has audited and closed all of Southern Company's consolidated federal income tax returns prior to 2009 and has settled its audits of Southern Company's consolidated federal income tax returns for 2009 and 2010, in principle, pending final approval. Additionally, the IRS has audited and closed Southern Company's 2011 consolidated federal income tax return. For tax years 2010 through 2013, Southern Company is a participant in the Compliance Assurance Process of the IRS. The audits for the Company's state income tax returns have either been concluded, or the statute of limitations has expired, for years prior to 2007.

Tax Method of Accounting for Repairs

Southern Company submitted a tax accounting method change related to the deductibility of repair costs associated with its subsidiaries' generation, transmission, and distribution systems effective for the 2009 consolidated federal income tax return in 2010. In August 2011, the IRS issued a revenue procedure, which provides a safe harbor method of accounting that taxpayers may use to determine eligible repair costs for transmission and distribution property. The IRS continues to work with the utility industry in an effort to define eligible repair costs for generation assets in a consistent manner for all utilities. The IRS published regulations on the deduction and capitalization of expenditures related to tangible property that generally apply for tax years beginning on or after January 1, 2014. The utility industry anticipates more detailed guidance concerning these regulations. Due to the uncertainty regarding the ultimate resolution of the repair costs for generation assets, an unrecognized tax position has been recorded for the tax accounting method change for repairs-generation assets. The ultimate outcome of this matter cannot be determined at this time; however, it is not expected to materially impact net income.

6. FINANCING

Bank Term Loans

In March 2012, the Company paid at maturity a $75 million aggregate principal amount variable rate bank note bearing interest at a rate based on one-month London Interbank Offered Rate (LIBOR).

In September 2012, the Company paid at maturity a $40 million aggregate principal amount variable rate bank note bearing interest at a rate based on one-month LIBOR.

In November 2012, the Company entered into a 366-day $100 million aggregate principal amount floating rate bank loan that bears interest based on one-month LIBOR. The first advance in the amount of $50 million was made in November 2012. Subsequent to December 31, 2012, the second advance in the amount of $50 million was made. The proceeds of this loan were used solely for working capital and for other general corporate purposes, including the Company's continuous construction program.

At December 31, 2012 and 2011, the Company had $175 million and $240 million of bank loans outstanding, respectively.

These bank loans have covenants that limit debt levels to 65% of total capitalization, as defined in the agreements. For purposes of these definitions, debt excludes the long-term debt payable to affiliated trusts and other hybrid securities. At December 31, 2012, the Company was in compliance with its debt limits.

In addition, these bank loans contain cross default provisions that would be triggered if the borrower defaulted on other indebtedness above a specified threshold. The cross default provisions are restricted to the indebtedness, including any guarantee obligations, of the company that has such bank loans. The Company is currently in compliance with all such covenants.

Senior Notes

In March 2012, the Company issued $250.0 million aggregate principal amount of Series 2012A 4.25% Senior Notes due March 15, 2042 and an additional $150.0 million aggregate principal amount of Series 2011A 2.35% Senior Notes due October 15, 2016. The Series 2011A Senior Notes were of the same series of notes that were originally issued in October 2011 in the aggregate principal amount of $150.0 million. Upon completion of this offering, the aggregate principal amount of the outstanding Series 2011A Senior Notes was $300.0 million. The proceeds from the sales of the Series 2012A Senior Notes and the Series 2011A Senior Notes were used to repay a bank term loan in an aggregate principal amount of $75.0 million and for general corporate purposes, including the Company's continuous construction program.

In March 2012, $300.0 million in interest rate swaps were settled, of which $250.0 million related to the Series 2012A Senior Notes at a loss of approximately $13.3 million, which will be amortized to interest expense, in earnings, over 10 years, and $50.0 million related to the Series 2011A Senior Notes at a loss of approximately $2.7 million, which will be amortized to interest expense, in earnings, over 10 years.

In May 2012, the Company redeemed $90.0 million aggregate principal amount of Series E 5-5/8% Senior Notes due May 1, 2033.

In August 2012, the Company issued an additional $200.0 million aggregate principal amount of Series 2012A 4.25% Senior Notes due March 15, 2042. The Series 2012A Senior Notes were of the same series of notes that were originally issued in March 2012 in the aggregate principal amount of $250.0 million. Upon completion of this offering, the aggregate principal amount of the outstanding Series 2012A Senior Notes is $450.0 million. The proceeds from this sale of the Series 2012A Senior Notes were used for general corporate purposes, including the Company's continuous construction program.

At December 31, 2012 and 2011, the Company had $1.1 billion and $630.0 million of senior notes outstanding, respectively. These senior notes are effectively subordinated to all secured debt of the Company. See "Plant Daniel Revenue Bonds" below for additional information regarding the Company's secured indebtedness.

Plant Daniel Revenue Bonds

In October 2011, in connection with the Company's election under its operating lease of Plant Daniel Units 3 and 4 to purchase the assets, the Company assumed the obligations of the lessor related to $270.0 million aggregate principal amount of Mississippi Business Finance Corporation Taxable Revenue Bonds, 7.13% Series 1999A due October 20, 2021, issued for the benefit of the lessor as described in Note 1 under "Purchase of the Plant Daniel Combined Cycle Generating Units" herein. These bonds are secured by Plant Daniel Units 3 and 4 and certain personal property. The bonds were recorded at fair value as of the date of assumption, or $346.1 million, reflecting a premium of $76.1 million.

Securities Due Within One Year

A summary of scheduled maturities and redemptions of securities due within one year at December 31, 2012 and 2011 was as follows:

	2012	2011
	(in millions)	
Senior notes	$ 50.0	$ —
Bank term loans	175.0	240.0
Revenue bonds	51.5	—
Capitalized leases	—	0.6
Outstanding at December 31	$ 276.5	$ 240.6

Maturities through 2017 applicable to total long-term debt are as follows: $276.5 million in 2013, $300.0 million in 2016, and $35.0 million in 2017. There are no scheduled maturities in 2014 and 2015.

Pollution Control Revenue Bonds

Pollution control obligations represent loans to the Company from public authorities of funds derived from sales by such authorities of revenue bonds issued to finance pollution control and solid waste disposal facilities. The Company is required to make payments sufficient for the authorities to meet principal and interest requirements of such bonds. The amount of tax-exempt pollution control revenue bonds outstanding at December 31, 2012 and 2011 was $82.7 million.

Other Revenue Bonds

Other revenue bond obligations represent loans to the Company from a public authority of funds derived from the sale by such authority of revenue bonds issued to finance a portion of the costs of constructing the Kemper IGCC and related facilities.

In August 2012, the Mississippi Business Finance Corporation (MBFC) entered into an agreement to issue up to $42.5 million aggregate principal amount of MBFC Taxable Revenue Bonds, Series 2012A (Mississippi Power Company Project), up to $21.25 million aggregate principal amount of MBFC Taxable Revenue Bonds, Series 2012B (Mississippi Power Company Project), and up to $21.25 million aggregate principal amount of MBFC Taxable Revenue Bonds, Series 2012C (Mississippi Power Company Project) for the benefit of the Company. During 2012, the MBFC issued $8.97 million aggregate principal amount of MBFC Taxable Revenue Bonds (Mississippi Power Company Project), Series 2012A, $21.25 million aggregate principal amount of MBFC Taxable Revenue Bonds (Mississippi Power Company Project), Series 2012B, and $21.25 million aggregate principal amount of MBFC Taxable Revenue Bonds (Mississippi Power Company Project), Series 2012C for the benefit of the Company. The proceeds were used to reimburse the Company for the cost of the acquisition, construction, equipping, installation, and improvement of certain equipment and facilities for the lignite mining facility related to the Kemper IGCC. Any future issuances of the Series 2012A bonds will be used for this same purpose.

The Company had $50.0 million of such obligations outstanding related to tax-exempt revenue bonds at December 31, 2012 and 2011, and $51.5 million of such obligations related to taxable revenue bonds outstanding at December 31, 2012. Such amounts are reflected in the statements of capitalization as long-term senior notes and debt.

Other Obligations

In March 2012, the Company received a $150.0 million interest-bearing refundable deposit from SMEPA to be applied to the sale price for the pending sale of an undivided interest in the Kemper IGCC. Until the acquisition is closed, the deposit bears interest at the Company's AFUDC rate adjusted for income taxes, which was 9.967% per annum at December 31, 2012, and is refundable to SMEPA upon termination of the asset purchase agreement related to such purchase, within 60 days of a request by SMEPA for a full or partial refund, or within 15 days at SMEPA's discretion in the event that the Company is assigned a senior unsecured credit rating of BBB+ or lower by S&P or Baal or lower by Moody's or ceases to be rated by either of these rating agencies.

Assets Subject to Lien

The revenue bonds assumed in conjunction with the purchase of Plant Daniel Units 3 and 4 are secured by Plant Daniel Units 3 and 4 and certain personal property. See Note 1 under "Purchase of the Plant Daniel Combined Cycle Generating Units" and "Plant Daniel Revenue Bonds" for additional information. There are no agreements or other arrangements among the Southern Company system companies under which the assets of one company have been pledged or otherwise made available to satisfy the obligations of Southern Company or another of its other subsidiaries.

Outstanding Classes of Capital Stock

The Company currently has preferred stock (including depositary shares which represent one-fourth of a share of preferred stock) and common stock authorized and outstanding. The preferred stock of the Company contains a feature that allows the holders to elect a majority of the Company's board of directors if dividends are not paid for four consecutive quarters. Because such a potential redemption-triggering event is not solely within the control of the Company, this preferred stock is presented as "Cumulative Redeemable Preferred Stock" in a manner consistent with temporary equity under applicable accounting standards. The Company's preferred stock and depositary preferred stock, without preference between classes, rank senior to the Company's common stock with respect to payment of dividends and voluntary or involuntary dissolution. The preferred stock and depositary preferred stock is subject to redemption at the option of the Company at a redemption price equal to 100% of the liquidation amount of the stock.

Dividend Restrictions

The Company can only pay dividends to Southern Company out of retained earnings or paid-in-capital.

Bank Credit Arrangements

At December 31, 2012, committed credit arrangements with banks were as follows:

Expires[a]				Executable Term-Loans		Due Within One Year	
2013	2014	Total	Unused	One Year	Two Years	Term Out	No Term Out
		(in millions)					
$135	$165	$300	$300	$25	$40	$65	$70

(a) No credit arrangements expire after 2014.

The Company expects to renew its credit arrangements, as needed, prior to expiration.

Most of these credit arrangements require payment of commitment fees based on the unused portions of the commitments or to maintain compensating balances with the banks. Commitment fees average less than 1/4 of 1% for the Company. Compensating balances are not legally restricted from withdrawal.

Most of these credit arrangements contain covenants that limit the Company's debt levels to 65% of total capitalization, as defined in the agreements. For purposes of these definitions, debt excludes certain hybrid securities.

In addition, the credit arrangements typically contain cross default provisions that are restricted to the indebtedness of the Company. The Company is currently in compliance with all such covenants. None of the arrangements contain material adverse change clauses at the time of borrowing.

The Company's unused credit arrangements provide liquidity support to the Company's variable rate pollution control revenue bonds and its commercial paper borrowings. The amount of variable rate pollution control revenue bonds outstanding requiring liquidity support as of December 31, 2012 was $40.1 million.

The Company makes short-term borrowings primarily through a commercial paper program that has the liquidity support of the Company's committed bank credit arrangements.

At December 31, 2012 and 2011, there was no short-term debt outstanding.

7. COMMITMENTS

Fuel and Purchased Power Agreements

To supply a portion of the fuel requirements of its generating plants, the Company has entered into various long-term commitments for the procurement of fossil fuel which are not recognized on the balance sheets. In 2012, 2011, and 2010, the Company incurred fuel expense of $411.2 million, $490.4 million, and $501.8 million, respectively, the majority of which was purchased under long-term commitments. The Company expects that a substantial amount of its future fuel needs will continue to be purchased under long-term commitments.

Coal commitments include a management fee of $38.1 million over the term of the executed 40-year management contract with Liberty Fuels beginning in 2014 related to the Kemper IGCC. Additional commitments for fuel will be required to supply the Company's future needs.

SCS may enter into various types of wholesale energy and natural gas contracts acting as an agent for the Company and all of the other Southern Company traditional operating companies and Southern Power. Under these agreements, each of the traditional operating companies and Southern Power may be jointly and severally liable. The credit rating of Southern Power is currently below that of the traditional operating companies. Accordingly, Southern Company has entered into keep-well agreements with the Company and each of the other traditional operating companies to ensure the Company will not subsidize or be responsible for any costs, losses, liabilities, or damages resulting from the inclusion of Southern Power as a contracting party under these agreements.

Operating Leases

The Company has operating lease agreements with various terms and expiration dates. Total rent expense was $11.1 million, $32.6 million, and $38.6 million for 2012, 2011, and 2010 respectively, which includes the Plant Daniel Units 3 and 4 operating lease that ended October 20, 2011.

The Company and Gulf Power have jointly entered into operating lease agreements for aluminum railcars for the transportation of coal at Plant Daniel. The Company has the option to purchase the railcars at the greater of lease termination value or fair market value, or to renew the leases at the end of the lease term. In early 2011, one operating lease expired and the Company elected not to exercise the option to purchase. The remaining operating lease has 229 aluminum railcars. The Company and Gulf Power also have separate lease agreements for other railcars that do not contain a purchase option.

The Company's share (50%) of the leases, charged to fuel stock and recovered through the fuel cost recovery clause, was $3.6 million in 2012, $2.6 million in 2011, and $3.5 million in 2010. The Company's annual railcar lease payments for 2013 through 2017 will average approximately $1.6 million.

In addition to railcar leases, the Company has other operating leases for fuel handling equipment at Plants Daniel and Watson and operating leases for barges and tow/shift boats for the transport of coal at Plant Watson. The Company's share (50% at Plant Daniel and 100% at Plant Watson) of the leases for fuel handling was charged to fuel handling expense in the amount of $0.2 million in 2012, $0.4 million in 2011, and $0.7 million in 2010. The Company's annual lease payments for 2013 through 2014 will average approximately $0.2 million for fuel handling equipment. The Company charged to fuel stock and recovered through fuel cost recovery the barge transportation leases in the amount of $7.3 million in 2012, $7.5 million in 2011, and $8.4 million in 2010 related to barges and tow/shift boats. The Company's annual lease payments for 2013 through 2014 with respect to these barge transportation leases will average approximately $8.2 million.

8. STOCK COMPENSATION

Stock Options

Southern Company provides non-qualified stock options through its Omnibus Incentive Compensation Plan to a large segment of the Company's employees ranging from line management to executives. As of December 31, 2012, there were 241 current and former employees of the Company participating in the stock option program and there were 39 million shares of Southern Company common stock remaining available for awards under the Omnibus Incentive Compensation Plan. The prices of options were at the fair market value of the shares on the dates of grant. These options become exercisable pro rata over a maximum period of three years from the date of grant. The Company generally recognizes stock option expense on a straight-line basis over the vesting period which equates to the requisite service period; however, for employees who are eligible for retirement, the total cost is expensed at the grant date. Options outstanding will expire no later than 10 years after the date of grant, unless terminated earlier by the Southern Company Board of Directors in accordance with the Omnibus Incentive Compensation Plan. For certain stock option awards, a change in control will provide accelerated vesting.

The estimated fair values of stock options granted were derived using the Black-Scholes stock option pricing model. Expected volatility was based on historical volatility of Southern Company's stock over a period equal to the expected term. Southern Company used historical exercise data to estimate the expected term that represents the period of time that options granted to employees are expected to be outstanding. The risk-free rate was based on the U.S. Treasury yield curve in effect at the time of grant that covers the expected term of the stock options.

The following table shows the assumptions used in the pricing model and the weighted average grant-date fair value of stock options granted:

Year Ended December 31	2012	2011	2010
Expected volatility	**17.7%**	17.5%	17.4%
Expected term *(in years)*	**5.0**	5.0	5.0
Interest rate	**0.9%**	2.3%	2.4%
Dividend yield	**4.2%**	4.8%	5.6%
Weighted average grant-date fair value	**$3.39**	$3.23	$2.23

The Company's activity in the stock option program for 2012 is summarized below:

	Shares Subject to Option	Weighted Average Exercise Price
Outstanding at December 31, 2011	1,569,728	$ 33.59
Granted	278,709	44.46
Exercised	(474,871)	31.98
Cancelled	—	—
Outstanding at December 31, 2012	**1,373,566**	**$ 36.34**
Exercisable at December 31, 2012	**864,634**	**$ 33.96**

The number of stock options vested, and expected to vest in the future, as of December 31, 2012 was not significantly different from the number of stock options outstanding at December 31, 2012 as stated above. As of December 31, 2012, the weighted average remaining contractual term for the options outstanding and options exercisable was approximately six years and five years, respectively, and the aggregate intrinsic value for the options outstanding and options exercisable was $9.3 million and $7.7 million, respectively.

As of December 31, 2012, there was $0.3 million of total unrecognized compensation cost related to stock option awards not yet vested. That cost is expected to be recognized over a weighted-average period of approximately 11 months.

For the years ended December 31, 2012, 2011, and 2010, total compensation cost for stock option awards recognized in income was $0.9 million, $0.8 million, and $0.8 million, respectively, with the related tax benefit also recognized in income of $0.3 million, $0.3 million, and $0.3 million, respectively.

The compensation cost and tax benefits related to the grant and exercise of Southern Company stock options to the Company's employees are recognized in the Company's financial statements with a corresponding credit to equity, representing a capital contribution from Southern Company.

The total intrinsic value of options exercised during the years ended December 31, 2012, 2011, and 2010 was $4.9 million, $4.2 million, and $2.7 million, respectively. The actual tax benefit realized by the Company for the tax deductions from stock option exercises totaled $1.9 million, $1.6 million, and $1.0 million for the years ended December 31, 2012, 2011, and 2010, respectively.

Performance Shares

Southern Company provides performance share award units through its Omnibus Incentive Compensation Plan to a large segment of the Company's employees ranging from line management to executives. The performance share units granted under the plan vest at the end of a three-year performance period which equates to the requisite service period. Employees that retire prior to the end of the three-year period receive a pro rata number of shares, issued at the end of the performance period, based on actual months of service prior to retirement. The value of the award units is based on Southern Company's total shareholder return

(TSR) over the three-year performance period which measures Southern Company's relative performance against a group of industry peers. The performance shares are delivered in common stock following the end of the performance period based on Southern Company's actual TSR and may range from 0% to 200% of the original target performance share amount.

The fair value of performance share awards is determined as of the grant date using a Monte Carlo simulation model to estimate the TSR of Southern Company's stock among the industry peers over the performance period. The Company recognizes compensation expense on a straight-line basis over the three-year performance period without remeasurement. Compensation expense for awards where the service condition is met is recognized regardless of the actual number of shares issued. The expected volatility was based on the historical volatility of Southern Company's stock over a period equal to the performance period. The risk-free rate was based on the U.S. Treasury yield curve in effect at the time of grant that covers the performance period of the award units.

The following table shows the assumptions used in the pricing model and the weighted average grant-date fair value of performance share award units granted:

Year Ended December 31	2012	2011	2010
Expected volatility	**16.0%**	19.2%	20.7%
Expected term *(in years)*	**3.0**	3.0	3.0
Interest rate	**0.4%**	1.4%	1.4%
Annualized dividend rate	**$1.89**	$1.82	$1.75
Weighted average grant-date fair value	**$41.99**	$35.97	$30.13

Total unvested performance share units outstanding as of December 31, 2011 were 70,830. During 2012, 33,077 performance share units were granted, 32,208 performance share units were vested, and 3,213 performance share units were forfeited resulting in 68,486 unvested units outstanding at December 31, 2012. In January 2013, the vested performance share award units were converted into 43,481 shares outstanding at a share price of $43.05 for the three-year performance and vesting period ended December 31, 2012.

For the years ended December 31, 2012, 2011, and 2010, total compensation cost for performance share units recognized in income was $1.2 million, $0.7 million, and $0.3 million, respectively, with the related tax benefit also recognized in income of $0.4 million, $0.3 million, and $0.1 million, respectively. As of December 31, 2012, there was $1.4 million of total unrecognized compensation cost related to performance share award units that will be recognized over a weighted-average period of approximately 11 months.

9. FAIR VALUE MEASUREMENTS

Fair value measurements are based on inputs of observable and unobservable market data that a market participant would use in pricing the asset or liability. The use of observable inputs is maximized where available and the use of unobservable inputs is minimized for fair value measurement and reflects a three-tier fair value hierarchy that prioritizes inputs to valuation techniques used for fair value measurement.

- Level 1 consists of observable market data in an active market for identical assets or liabilities.
- Level 2 consists of observable market data, other than that included in Level 1, that is either directly or indirectly observable.
- Level 3 consists of unobservable market data. The input may reflect the assumptions of the Company of what a market participant would use in pricing an asset or liability. If there is little available market data, then the Company's own assumptions are the best available information.

In the case of multiple inputs being used in a fair value measurement, the lowest level input that is significant to the fair value measurement represents the level in the fair value hierarchy in which the fair value measurement is reported.

As of December 31, 2012, assets and liabilities measured at fair value on a recurring basis during the period, together with the level of the fair value hierarchy in which they fall, were as follows:

	Fair Value Measurements Using			
As of December 31, 2012:	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
		(in thousands)		
Assets:				
Energy-related derivatives	$ —	$ 2,519	$ —	$ 2,519
Foreign currency derivatives	—	—	—	—
Cash equivalents	125,600	—	—	125,600
Total	$ 125,600	$ 2,519	$ —	$ 128,119
Liabilities:				
Energy-related derivatives	$ —	$ 19,446	$ —	$ 19,446
Interest rate derivatives	—	—	—	—
Foreign currency derivatives	—	37	—	37
Total	$ —	$ 19,483	$ —	$ 19,483

As of December 31, 2011, assets and liabilities measured at fair value on a recurring basis during the period, together with the level of the fair value hierarchy in which they fall, were as follows:

	Fair Value Measurements Using			
As of December 31, 2011:	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
		(in thousands)		
Assets:				
Energy-related derivatives	$ —	$ 162	$ —	$ 162
Foreign currency derivatives	—	1,526	—	1,526
Cash equivalents	133,900	—	—	133,900
Total	$ 133,900	$ 1,688	$ —	$ 135,588
Liabilities:				
Energy-related derivatives	$ —	$ 51,152	$ —	$ 51,152
Interest rate derivatives	—	15,208	—	15,208
Foreign currency derivatives	—	2,510	—	2,510
Total	$ —	$ 68,870	$ —	$ 68,870

Valuation Methodologies

The energy-related derivatives primarily consist of over-the-counter financial products for natural gas and physical power products including, from time to time, basis swaps. These are standard products used within the energy industry and are valued using the market approach. The inputs used are mainly from observable market sources, such as forward natural gas prices, power prices, implied volatility, and LIBOR interest rates. Interest rate and foreign currency derivatives are also standard over-the-counter financial products valued using the market approach. Inputs for interest rate derivatives include LIBOR interest rates, interest rate futures contracts, and occasionally implied volatility of interest rate options. Inputs for foreign currency derivatives are from observable market sources. See Note 10 for additional information on how these derivatives are used.

As of December 31, 2012 and 2011, the fair value measurements of investments calculated at net asset value per share (or its equivalent), as well as the nature and risks of those investments, were as follows:

	Fair Value	Unfunded Commitments	Redemption Frequency	Redemption Notice Period
As of December 31, 2012	*(in thousands)*			
Cash equivalents:				
Money market funds	$ 125,600	None	Daily	Not applicable
As of December 31, 2011				
Cash equivalents:				
Money market funds	$ 133,900	None	Daily	Not applicable

The money market funds are short-term investments of excess funds in various money market mutual funds, which are portfolios of short-term debt securities. The money market funds are regulated by the SEC and typically receive the highest rating from credit rating agencies. Regulatory and rating agency requirements for money market funds include minimum credit ratings and maximum maturities for individual securities and a maximum weighted average portfolio maturity. Redemptions are available on a same day basis up to the full amount of the Company's investment in the money market funds.

As of December 31, 2012 and 2011, other financial instruments for which the carrying amount did not equal fair value were as follows:

	Carrying Amount	Fair Value
	(in thousands)	
Long-term debt:		
2012	**$ 1,840,933**	**$ 1,956,799**
2011	$ 1,343,596	$ 1,426,808

The fair values are determined using primarily Level 2 measurements and are based on quoted market prices for the same or similar issues or on the current rates offered to the Company.

10. DERIVATIVES

The Company is exposed to market risks, primarily commodity price risk and interest rate risk and occasionally foreign currency risk. To manage the volatility attributable to these exposures, the Company nets its exposures, where possible, to take advantage of natural offsets and enters into various derivative transactions for the remaining exposures pursuant to the Company's policies in areas such as counterparty exposure and risk management practices. The Company's policy is that derivatives are to be used primarily for hedging purposes and mandates strict adherence to all applicable risk management policies. Derivative positions are monitored using techniques including, but not limited to, market valuation, value at risk, stress testing, and sensitivity analysis. Derivative instruments are recognized at fair value in the balance sheets as either assets or liabilities and are presented on a gross basis.

Energy-Related Derivatives

The Company enters into energy-related derivatives to hedge exposures to electricity, gas, and other fuel price changes. However, due to cost-based rate regulations and other various cost recovery mechanisms, the Company has limited exposure to market volatility in commodity fuel prices and prices of electricity. The Company manages fuel hedging programs, implemented per the guidelines of the Mississippi PSC, through the use of financial derivative contracts, which is expected to continue to mitigate price volatility.

To mitigate residual risks relative to movements in electricity prices, the Company may enter into physical fixed-price or heat rate contracts for the purchase and sale of electricity through the wholesale electricity market. To mitigate residual risks relative to movements in gas prices, the Company may enter into fixed-price contracts for natural gas purchases; however, a significant portion of contracts are priced at market.

Energy-related derivative contracts are accounted for in one of three methods:

- *Regulatory Hedges* – Energy-related derivative contracts which are designated as regulatory hedges relate primarily to the Company's fuel hedging programs, where gains and losses are initially recorded as regulatory liabilities and assets, respectively, and then are included in fuel expense as the underlying fuel is used in operations and ultimately recovered through the respective fuel cost recovery clauses.
- *Cash Flow Hedges* – Gains and losses on energy-related derivatives designated as cash flow hedges which are mainly used to hedge anticipated purchases and sales and are initially deferred in OCI before being recognized in the statements of income in the same period as the hedged transactions are reflected in earnings.
- *Not Designated* – Gains and losses on energy-related derivative contracts that are not designated or fail to qualify as hedges are recognized in the statements of income as incurred.

Some energy-related derivative contracts require physical delivery as opposed to financial settlement, and this type of derivative is both common and prevalent within the electric industry. When an energy-related derivative contract is settled physically, any cumulative unrealized gain or loss is reversed and the contract price is recognized in the respective line item representing the actual price of the underlying goods being delivered.

At December 31, 2012, the net volume of energy-related derivative contracts for natural gas positions for the Company, together with the longest hedge date over which it is hedging its exposure to the variability in future cash flows for forecasted transactions and the longest date for derivatives not designated as hedges, were as follows:

	Gas	
Net Purchased mmBtu*	Longest Hedge Date	Longest Non-Hedge Date
(in millions)		
38	2017	—

* mmBtu — million British thermal units

For cash flow hedges, the amounts expected to be reclassified from OCI to revenue and fuel expense for the next 12-month period ending December 31, 2013 are immaterial.

Foreign Currency Derivatives

The Company may enter into foreign currency derivatives to hedge exposure to changes in foreign currency exchange rates arising from purchases of equipment denominated in a currency other than U.S. dollars. Derivatives related to a firm commitment in a foreign currency transaction are accounted for as a fair value hedge where the derivatives' fair value gains or losses and the hedged items' fair value gains or losses are both recorded directly to earnings. Derivatives related to a forecasted transaction are accounted for as a cash flow hedge where the effective portion of the derivatives' fair value gains or losses is recorded in OCI and is reclassified into earnings at the same time the hedged transactions affect earnings. Any ineffectiveness is typically recorded directly to earnings, however, the Company has regulatory approval allowing it to defer any ineffectiveness associated with firm commitments related to the Kemper IGCC to a regulatory asset. During the year ended December 31, 2011, certain fair value hedges were de-designated and subsequently settled in 2012. The ineffectiveness related to the de-designated hedges was recorded as a regulatory asset and was immaterial to the Company. The derivatives employed as hedging instruments are structured to minimize ineffectiveness.

At December 31, 2012, the following foreign currency derivatives were outstanding:

	Notional Amount	Forward Rate	Hedge Maturity Date	Fair Value Gain (Loss) December 31, 2012
	(in thousands)			*(in thousands)*
Fair value hedges of firm commitments				
	EUR735	1.3758 Dollars per Euro	March 2014	$(37)

Interest Rate Derivatives

The Company may also enter into interest rate derivatives to hedge exposure to changes in interest rates. Derivatives related to existing variable rate securities or forecasted transactions are accounted for as cash flow hedges where the effective portion of the derivatives' fair value gains or losses is recorded in OCI and is reclassified into earnings at the same time the hedged transactions affect earnings. The derivatives employed as hedging instruments are structured to minimize ineffectiveness, which is recorded directly to income.

At December 31, 2012, there were no interest rate derivatives outstanding.

For the year ended December 31, 2012, the Company had realized net losses of $16.0 million upon termination of certain interest rate derivatives at the same time the related debt was issued. The effective portion of these losses has been deferred in OCI and is being amortized to interest expense over the life of the original interest rate derivative, reflecting the period in which the forecasted hedged transaction affects earnings.

The estimated pre-tax losses that will be reclassified from OCI to interest expense for the 12-month period ending December 31, 2013 are $1.4 million. The Company has deferred gains and losses that are expected to be amortized into earnings through 2022.

Derivative Financial Statement Presentation and Amounts

At December 31, 2012 and 2011, the fair value of energy-related derivatives, foreign currency derivatives, and interest rate derivatives was reflected in the balance sheets as follows:

	Asset Derivatives			Liability Derivatives		
Derivative Category	**Balance Sheet Location**	**2012**	2011	**Balance Sheet Location**	**2012**	2011
		(in thousands)			*(in thousands)*	
Derivatives designated as hedging instruments for regulatory purposes						
Energy-related derivatives:	Other current assets	**$ 638**	$ 125	Liabilities from risk management activities	**$ 13,116**	$ 36,455
	Other deferred charges and assets	**1,881**	37	Other deferred credits and liabilities	**6,330**	14,697
Total derivatives designated as hedging instruments for regulatory purposes		**$ 2,519**	$ 162		**$ 19,446**	$ 51,152
Derivatives designated as hedging instruments in cash flow and fair value hedges						
Energy-related derivatives:	Other current assets	**$ —**	$ —	Liabilities from risk management activities	**$ —**	$ —
Interest rate derivatives:	Other current assets	**—**	—	Liabilities from risk management activities	**—**	15,208
Foreign currency derivatives:	Other current assets	**—**	19	Liabilities from risk management activities	**—**	625
	Other deferred charges and assets	**—**	—	Other deferred credits and liabilities	**37**	46
Total derivatives designated as hedging instruments in cash flow and fair value hedges		**$ —**	$ 19		**$ 37**	$ 15,879
Derivatives not designated as hedging instruments						
Energy-related derivatives:	Other current assets	**$ —**	$ —	Liabilities from risk management activities	**$ —**	$ —
Foreign currency derivatives:	Other current assets	**—**	1,507	Liabilities from risk management activities	**—**	1,839
Total derivatives not designated as hedging instruments		**$ —**	$ 1,507		**$ —**	$ 1,839
Total		**$ 2,519**	$ 1,688		**$ 19,483**	$ 68,870

All derivative instruments are measured at fair value. See Note 9 for additional information.

At December 31, 2012 and 2011, the pre-tax effects of unrealized derivative gains (losses) arising from energy-related derivative instruments designated as regulatory hedging instruments and deferred on the balance sheets were as follows:

	Unrealized Losses			Unrealized Gains		
Derivative Category	**Balance Sheet Location**	**2012**	2011	**Balance Sheet Location**	**2012**	2011
		(in thousands)			*(in thousands)*	
Energy-related derivatives:	Other regulatory assets, current	**$ (13,116)**	$ (36,455)	Other regulatory liabilities, current	**$ 638**	$ 125
	Other regulatory assets, deferred	**(6,330)**	(14,697)	Other regulatory liabilities, deferred	**1,881**	37
Total energy-related derivative gains (losses)		**$ (19,446)**	$ (51,152)		**$ 2,519**	$ 162

For the years ended December 31, 2012, 2011, and 2010, the pre-tax effects of derivatives designated as cash flow hedging instruments on the statements of income were as follows:

Derivatives in Cash Flow Hedging Relationships	**Gain (Loss) Recognized in OCI on Derivative (Effective Portion)**			**Gain (Loss) Reclassified from Accumulated OCI into Income (Effective Portion)**			
					Amount		
Derivative Category	**2012**	2011	2010	**Statements of Income Location**	**2012**	2011	2010
	(in thousands)				*(in thousands)*		
Energy-related derivatives	**$ —**	$ (3)	$ 3	Fuel	**$ —**	$ —	$ —
Interest rate derivatives	**(774)**	(14,361)	—	Interest Expense	**(1,073)**	48	—
Total	**$ (774)**	$ (14,364)	$ 3		**$ (1,073)**	$ 48	$ —

There was no material ineffectiveness recorded in earnings for any period presented.

For the years ended December 31, 2012, 2011, and 2010, the pre-tax effects of energy-related derivatives not designated as hedging instruments on the statements of income were immaterial. For the year ended December 31, 2012, the pre-tax effect of foreign currency derivatives not designated as hedging instruments was recorded as a regulatory asset and was immaterial to the Company.

For the years ended December 31, 2012 and 2011, the pre-tax effects of foreign currency derivatives designated as fair value hedging instruments, which include a pre-tax loss associated with de-designated hedges prior to de-designation, on the Company's statements of income were a $0.6 million gain and $3.6 million loss, respectively. For the year ended December 31, 2010, the pre-tax gain was $3.3 million. These amounts were offset by changes in the fair value of the purchase commitment related to equipment purchases. Therefore, there is no impact on the Company's statements of income.

Contingent Features

The Company does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. There are certain derivatives that could require collateral, but not accelerated payment, in the event of various credit rating changes of certain affiliated companies. At December 31, 2012, the fair value of derivative liabilities with contingent features was $2.9 million.

At December 31, 2012, the Company had no collateral posted with its derivative counterparties; however, because of the joint and several liability features underlying these derivatives, the maximum potential collateral requirements arising from the credit-risk-related contingent features, at a rating below BBB- and/or Baa3, were $15.1 million.

Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. The Company participates in certain agreements that could require collateral in the event that one or more Southern Company system power pool participants has a credit rating change to below investment grade.

11. QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

Summarized quarterly financial information for 2012 and 2011 is as follows:

Quarter Ended	Operating Revenues	Operating Income	Net Income After Dividends on Preferred Stock
		(in thousands)	
March 2012	**$ 228,714**	**$ 30,213**	**$ 25,255**
June 2012	**266,084**	**46,986**	**35,027**
September 2012	**305,419**	**66,151**	**54,625**
December 2012	**235,779**	**31,662**	**33,200**
March 2011	$ 263,276	$ 25,151	$ 14,617
June 2011	286,041	39,056	25,283
September 2011	325,766	53,171	38,019
December 2011	237,794	16,412	16,263

The Company's business is influenced by seasonal weather conditions.

SELECTED FINANCIAL AND OPERATING DATA 2008-2012
Mississippi Power Company 2012 Annual Report

	2012	2011	2010	2009	2008
Operating Revenues (in thousands)	**$ 1,035,996**	$ 1,112,877	$ 1,143,068	$ 1,149,421	$ 1,256,542
Net Income After Dividends on Preferred Stock (in thousands)	**$ 148,107**	$ 94,182	$ 80,217	$ 84,967	$ 85,960
Cash Dividends on Common Stock (in thousands)	**$ 106,800**	$ 75,500	$ 68,600	$ 68,500	$ 68,400
Return on Average Common Equity (percent)	**10.41**	10.54	11.49	13.12	13.75
Total Assets (in thousands)	**$ 5,451,621**	$ 3,671,842	$ 2,476,321	$ 2,072,681	$ 1,952,695
Gross Property Additions (in thousands)	**$ 1,665,498**	$ 1,205,704	$ 340,162	$ 95,573	$ 139,250
Capitalization (in thousands):					
Common stock equity	**$ 1,797,373**	$ 1,049,217	$ 737,368	$ 658,522	$ 636,451
Redeemable preferred stock	**32,780**	32,780	32,780	32,780	32,780
Long-term debt	**1,564,462**	1,103,596	462,032	493,480	370,460
Total (excluding amounts due within one year)	**$ 3,394,615**	$ 2,185,593	$ 1,232,180	$ 1,184,782	$ 1,039,691
Capitalization Ratios (percent):					
Common stock equity	**52.9**	48.0	59.8	55.6	61.2
Redeemable preferred stock	**1.0**	1.5	2.7	2.8	3.2
Long-term debt	**46.1**	50.5	37.5	41.6	35.6
Total (excluding amounts due within one year)	**100.0**	100.0	100.0	100.0	100.0
Customers (year-end):					
Residential	**152,265**	151,805	151,944	151,375	152,280
Commercial	**33,112**	33,200	33,121	33,147	33,589
Industrial	**472**	496	504	513	518
Other	**175**	175	187	180	183
Total	**186,024**	185,676	185,756	185,215	186,570
Employees (year-end)	**1,281**	1,264	1,280	1,285	1,317

	2012	2011	2010	2009	2008
Operating Revenues (in thousands):					
Residential	$ 226,847	$ 246,510	$ 256,994	$ 245,357	$ 248,693
Commercial	250,860	263,256	266,406	269,423	271,452
Industrial	262,978	275,752	267,588	269,128	258,328
Other	6,768	6,945	6,924	7,041	6,961
Total retail	747,453	792,463	797,912	790,949	785,434
Wholesale — non-affiliates	255,557	273,178	287,917	299,268	353,793
Wholesale — affiliates	16,403	30,417	41,614	44,546	100,928
Total revenues from sales of electricity	1,019,413	1,096,058	1,127,443	1,134,763	1,240,155
Other revenues	16,583	16,819	15,625	14,658	16,387
Total	$ 1,035,996	$ 1,112,877	$ 1,143,068	$ 1,149,421	$ 1,256,542
Kilowatt-Hour Sales (in thousands):					
Residential	2,045,999	2,162,419	2,296,157	2,091,825	2,121,389
Commercial	2,915,934	2,870,714	2,921,942	2,851,248	2,856,744
Industrial	4,701,681	4,586,356	4,466,560	4,329,924	4,187,101
Other	38,588	38,684	38,570	38,855	38,886
Total retail	9,702,202	9,658,173	9,723,229	9,311,852	9,204,120
Wholesale — non-affiliates	3,818,773	4,009,637	4,284,289	4,651,606	5,016,655
Wholesale — affiliates	571,908	648,772	774,375	839,372	1,487,083
Total	14,092,883	14,316,582	14,781,893	14,802,830	15,707,858
Average Revenue Per Kilowatt-Hour (cents):					
Residential	11.09	11.40	11.19	11.73	11.72
Commercial	8.60	9.17	9.12	9.45	9.50
Industrial	5.59	6.01	5.99	6.22	6.17
Total retail	7.70	8.21	8.21	8.49	8.53
Wholesale	6.19	6.52	6.51	6.26	6.99
Total sales	7.23	7.66	7.63	7.67	7.90
Residential Average Annual Kilowatt-Hour Use Per Customer	13,426	14,229	15,130	13,762	13,992
Residential Average Annual Revenue Per Customer	$ 1,489	$ 1,622	$ 1,693	$ 1,614	$ 1,640
Plant Nameplate Capacity Ratings (year-end) (megawatts)	3,088	3,156	3,156	3,156	3,156
Maximum Peak-Hour Demand (megawatts):					
Winter	2,168	2,618	2,792	2,392	2,385
Summer	2,435	2,462	2,638	2,522	2,458
Annual Load Factor (percent)	61.9	59.1	57.9	60.7	61.5
Plant Availability Fossil-Steam (percent)*	91.5	87.7	93.8	94.1	91.6
Source of Energy Supply (percent):					
Coal	22.8	34.9	43.0	40.0	58.7
Oil and gas	63.9	51.5	41.9	43.6	28.6
Purchased power -					
From non-affiliates	2.0	1.4	1.3	3.3	4.4
From affiliates	11.3	12.2	13.8	13.1	8.3
Total	100.0	100.0	100.0	100.0	100.0

* Beginning in 2012, plant availability is calculated as a weighted equivalent availability.

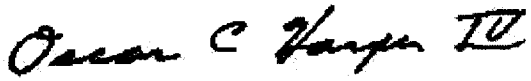
SOUTHERN POWER COMPANY

FINANCIAL SECTION

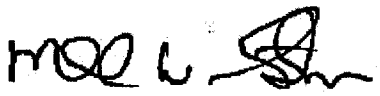
MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING
Southern Power Company and Subsidiary Companies 2012 Annual Report

The management of Southern Power Company (the Company) is responsible for establishing and maintaining an adequate system of internal control over financial reporting as required by the Sarbanes-Oxley Act of 2002 and as defined in Exchange Act Rule 13a-15(f). A control system can provide only reasonable, not absolute, assurance that the objectives of the control system are met.

Under management's supervision, an evaluation of the design and effectiveness of the Company's internal control over financial reporting was conducted based on the framework in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, management concluded that the Company's internal control over financial reporting was effective as of December 31, 2012.



Oscar C. Harper, IV
President and Chief Executive Officer



Michael W. Southern
Senior Vice President and Chief Financial Officer

February 27, 2013

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of
Southern Power Company

We have audited the accompanying consolidated balance sheets of Southern Power Company and Subsidiary Companies (the Company) (a wholly owned subsidiary of The Southern Company) as of December 31, 2012 and 2011, and the related consolidated statements of income, comprehensive income, common stockholder's equity, and cash flows for each of the three years in the period ended December 31, 2012. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements (pages II-465 to II-487) present fairly, in all material respects, the financial position of Southern Power Company and Subsidiary Companies as of December 31, 2012 and 2011, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2012, in conformity with accounting principles generally accepted in the United States of America.

Deloitte & Touche LLP

Atlanta, Georgia
February 27, 2013

OVERVIEW

Business Activities

Southern Power Company and its subsidiaries (the Company) construct, acquire, own, and manage generation assets, including renewable energy projects, and sell electricity at market-based rates in the wholesale market. The Company continues to execute its strategy through a combination of acquiring and constructing new power plants and by entering into power purchase agreements (PPAs) primarily with investor owned utilities, independent power producers, municipalities, and electric cooperatives. In general, the Company has constructed or acquired new generating capacity only after entering into long-term capacity contracts for the new facilities.

In June 2012, the Company completed construction of Plant Nacogdoches, a biomass generating plant near Sacul, Texas with a nameplate capacity of approximately 116 megawatts (MWs). The Company has a PPA covering the entire output of the plant from 2012 through 2032.

In December 2012, the Company completed construction of Plant Cleveland Units 1 through 4, a combustion turbine natural gas generating plant, in Cleveland County, North Carolina. The plant has a nameplate capacity of 720 MWs. The Company has long-term PPAs for 540 MWs of the generating capacity of the plant.

In 2012, the Company and Turner Renewable Energy, Inc. (TRE), through Southern Turner Renewable Energy LLC (STR), a jointly-owned subsidiary owned 90% by the Company, acquired all of the outstanding membership interests of Apex Nevada Solar, LLC (Apex), Spectrum Nevada Solar, LLC (Spectrum), and Granville Solar, LLC (Granville). Apex owns a 20-MW solar photovoltaic facility in North Las Vegas, Nevada. The solar facility began commercial operation on July 21, 2012 and has a PPA covering the entire output of the plant from 2012 through 2037. Granville owns a 2.5-MW solar photovoltaic facility in Oxford, North Carolina. The solar facility began commercial operation on October 28, 2012 and has a PPA covering the entire output of the plant from 2012 through 2032. Spectrum is constructing a 30-MW solar photovoltaic facility in North Las Vegas, Nevada. The solar facility is expected to begin commercial operation in mid-2013 and has a PPA covering the entire output of the plant from 2013 through 2038. These acquisitions added a total of 47 MWs of solar capacity to the Company's generation portfolio and are in accordance with the Company's overall growth strategy. See FUTURE EARNINGS POTENTIAL – "Acquisitions" herein and Note 2 to the financial statements for additional information.

As of December 31, 2012, the Company had units totaling 8,764 MWs nameplate capacity in commercial operation. The average remaining duration of the Company's wholesale contracts exceeds 10 years, which reduces remarketing risk. The Company has entered into long-term power sales agreements for an average of 77% of its available capacity for the next five years and 70% of its available capacity for the next 10 years. The Company's future earnings will depend on the parameters of the wholesale market and the efficient operation of its wholesale generating assets. See FUTURE EARNINGS POTENTIAL herein for additional information.

Key Performance Indicators

To evaluate operating results and to ensure the Company's ability to meet its contractual commitments to customers, the Company focuses on several key performance indicators. These indicators include peak season equivalent forced outage rate (Peak Season EFOR), contract availability, and net income. Peak Season EFOR defines the hours during peak demand times when the Company's generating units are not available due to forced outages (the lower the better). Contract availability measures the percentage of scheduled hours delivered. Net income is the primary measure of the Company's financial performance. The Company's actual performance in 2012 met or surpassed targets in these key performance areas. See RESULTS OF OPERATIONS herein for additional information on the Company's net income for 2012.

Earnings

The Company's 2012 net income was $175.3 million, a $13.1 million increase compared to 2011. This increase was primarily due to higher energy revenues from sales to affiliates under the Intercompany Interchange Contract (IIC), higher capacity revenues due to an increase in total MWs of capacity under long-term contracts, lower fuel and purchase power expenses, lower interest expense, and a loss on early redemption of long-term debt in 2011. This increase was partially offset by lower energy revenues from non-affiliates, higher depreciation and amortization, and higher income tax expense.

The Company's 2011 net income was $162.2 million, a $30.9 million increase compared to 2010. This increase was primarily due to higher energy and capacity revenues. This increase was partially offset by higher fuel expenses, higher operations and maintenance expenses, a loss on early redemption of long-term debt, and higher depreciation and amortization.

RESULTS OF OPERATIONS

A condensed statement of income follows:

	Amount	Increase (Decrease) from Prior Year	
	2012	2012	2011
		(in millions)	
Operating revenues	$ 1,186.0	$ (49.9)	$ 105.6
Fuel	426.3	(28.5)	63.3
Purchased power	93.3	(37.9)	(38.8)
Other operations and maintenance	173.1	1.5	23.3
Loss (gain) on sale of property	—	—	(0.5)
Depreciation and amortization	142.6	18.4	4.8
Taxes other than income taxes	19.3	1.6	(0.1)
Total operating expenses	854.6	(44.9)	52.0
Operating income	331.4	(5.0)	53.6
Interest expense, net of amounts capitalized	62.5	(14.8)	1.2
Loss on extinguishment of debt	—	19.8	(19.8)
Other income (expense), net	(1.0)	0.2	(1.2)
Income taxes	92.6	16.7	0.5
Net income	$ 175.3	$ 13.1	$ 30.9

Operating Revenues

Operating revenues for 2012 were $1.19 billion, reflecting a $49.9 million decrease from 2011. Details of operating revenues are as follows:

	2012	2011	2010
		(in millions)	
Capacity revenues —			
Affiliates	$ 125.9	$ 146.5	$ 190.6
Non-affiliates	372.6	322.7	257.4
Total	498.5	469.2	448.0
Energy revenues —			
Affiliates	35.6	39.3	46.1
Non-affiliates	346.7	482.9	401.1
Total	382.3	522.2	447.2
Total PPA revenues	880.8	991.4	895.2
Revenues not covered by PPA	298.0	237.8	228.2
Other revenues	7.2	6.7	6.9
Total Operating Revenues	$ 1,186.0	$ 1,235.9	$ 1,130.3

The decrease in operating revenues was primarily due to a $139.9 million decrease in energy sales under PPAs, reflecting a 25.8% reduction in the average price of energy and a 1.3% decrease in kilowatt-hours (KWH) sales. This decrease was partially offset by a $60.3 million increase in energy sales not covered by PPAs, reflecting a 78.5% increase in KWH sales, partially offset by a 29.7% reduction in the average price of energy. Overall, energy sales decreased $79.6 million, reflecting a 22.1% reduction in the average price of energy, partially offset by a 14.9% increase in KWH sales. The decrease in operating revenues from energy sales was partially offset by a $29.3 million increase in capacity revenues due to an increase in the total MWs of capacity under contract.

Operating revenues in 2011 were $1.24 billion, a $105.6 million (9.3%) increase from 2010. This increase was primarily due to a $75.0 million increase in energy sales under PPAs, reflecting an 11.2% increase in KWH sales and a 5.1% increase in the average price of energy. This increase was also due to a $14.0 million increase in energy sales not covered by PPAs, reflecting a 48.5% increase in KWH sales, partially offset by a 28.4% reduction in the average price of energy. Overall, energy sales increased $89.0 million, reflecting a 17.1% increase in KWH sales, partially offset by a 3.3% decrease in the average price of energy. The increase in operating revenue from energy sales was also due to a $16.8 million increase in capacity revenue due to an increase in the total MWs of capacity under contract.

Wholesale revenues from sales to affiliated companies will vary depending on demand and the availability and cost of generating resources at each company. Sales to affiliate companies that are not covered by PPAs are made in accordance with the IIC, as approved by the Federal Energy Regulatory Commission (FERC).

Capacity revenues are an integral component of the Company's PPAs with both affiliate and non-affiliate customers and generally represent the greatest contribution to net income. Energy under the PPAs is generally sold at variable cost or is indexed to published gas indices. Energy revenues also include fees for support services, fuel storage, and unit start charges.

Fuel and Purchased Power Expenses

Fuel costs constitute the single largest expense for the Company. Additionally, the Company purchases a portion of its electricity needs from the wholesale market.

Details of the Company's fuel and purchased power expenditures are as follows:

	2012	2011	2010
		(in millions)	
Fuel	$ 426.3	$ 454.8	$ 391.5
Purchased power-non-affiliates	80.4	78.4	72.7
Purchased power-affiliates	12.9	52.9	97.4
Total fuel and purchased power expenses	$ 519.6	$ 586.1	$ 561.6

In 2012, total fuel and purchased power expenses decreased by $66.5 million (11.3%) compared to 2011. Total fuel and purchased power expenses decreased $183.6 million, primarily due to a 26.6% decrease in the average cost of fuel and a 23.0% decrease in the average cost of purchased power. This decrease was partially offset by a $117.1 million increase associated with a 21.4% net increase in the volume of KWHs generated and purchased. In 2011, total fuel and purchased power expenses increased by $24.5 million (4.4%) compared to 2010. Total fuel and purchased power expenses increased $144.2 million, primarily due to a 28.0% increase in KWHs generated and purchased. This increase was partially offset by a decrease of $119.7 million due to a 30.0% decrease in the cost of purchased power and a 12.1% decrease in the average cost of natural gas generation.

In 2012, fuel expense decreased by $28.5 million (6.3%) compared to 2011. Fuel expense decreased primarily due to a $155.7 million decrease associated with the cost of fuel, partially offset by a $127.2 million increase associated with the volume of KWHs generated. In 2011, fuel expense increased by $63.3 million (16.2%) compared to 2010. Fuel expense increased $126.7 million primarily due to an increase in the volume of KWHs generated, partially offset by a $63.4 million decrease due to a 12.1% decline in the average cost of natural gas generation.

In 2012, purchased power expense decreased $37.9 million (28.9%) compared to 2011. Purchased power expense decreased primarily due to a $27.8 million decrease associated with the cost of purchased power and a $10.1 million decrease associated with the volume of KWHs purchased. In 2011, purchased power expense decreased $38.8 million (22.8%) compared to 2010. Purchased power expense decreased $56.3 million associated with the cost of purchased power, partially offset by a $17.5 million increase due to an increase in the volume of KWHs purchased.

The Company's PPAs generally provide that the purchasers are responsible for substantially all of the cost of fuel. Consequently, any increase or decrease in fuel costs is generally accompanied by an increase or decrease in related fuel revenues and does not have a significant impact on net income. The Company is responsible for the cost of fuel for generating units that are not covered under PPAs. Power from these generating units is sold into the market or sold to affiliates under the IIC.

Purchased power expenses will vary depending on demand and the availability and cost of generating resources available throughout the Southern Company system and other contract resources. Load requirements are submitted to the power pool on an hourly basis and are fulfilled with the lowest cost alternative, whether that is generation owned by the Company, affiliate-owned generation, or external purchases.

Other Operations and Maintenance Expenses

In 2012, other operations and maintenance expenses increased $1.5 million (0.9%) compared to 2011. This increase was primarily due to a $7.8 million increase in administrative and general expenses due to expenses associated with business development and affiliate service company costs allocated based on load and fuel burn and a $1.2 million increase in transmission cost, partially offset by a $7.4 million decrease in generating plant scheduled outages and maintenance in 2012.

In 2011, other operations and maintenance expenses increased $23.3 million (15.7%) compared to 2010. This increase was primarily due to an increase of $17.1 million related to generating plant scheduled outages and maintenance, an increase of $3.3 million related to labor costs across the fleet, and a $4.9 million increase in administrative and general expenses due to costs associated with strategic planning, legal fees, and additional expenses in 2011 related to information technology upgrades. These increases were partially offset by a $4.1 million decrease attributable to additional expense recognized in 2010 associated with the passage of healthcare legislation.

Depreciation and Amortization

In 2012, depreciation and amortization increased $18.4 million (14.8%) compared to 2011. This increase was primarily due to a $17.2 million increase in depreciation resulting from an increase in plant in service, including the additions of Plant Nacogdoches, Plant Apex, Plant Granville, and Plant Cleveland, and a $2.5 million increase due to higher depreciation rates from the depreciation study adopted in January 2012, partially offset by a $1.3 million decrease in depreciation related to asset retirements.

In 2011, depreciation and amortization increased $4.8 million (4.1%) compared to 2010. This increase was primarily related to an $8.0 million increase in depreciation rates associated with increased starts and run-hours at the Company's generating plants, which shortened the estimated depreciable life of some components, and a $3.3 million increase associated with the acquisition of Plant Cimarron. These increases were partially offset by a $7.5 million decrease due to higher expenses in 2010 related to equipment retirements.

See ACCOUNTING POLICIES – "Depreciation" herein for additional information regarding the Company's ongoing review of depreciation estimates. See also Note 1 to the financial statements under "Depreciation" for additional information.

Interest Expense, Net of Amounts Capitalized

In 2012, interest expense, net of amounts capitalized decreased $14.8 million (19.2%) compared to 2011. This decrease was primarily due to a $13.7 million expense reduction associated with the refinancing of $575 million in long-term debt in December 2011 and a $1.1 million increase in capitalized interest associated with the construction of Plant Cleveland and Plant Nacogdoches.

In 2011, interest expense, net of amounts capitalized increased $1.2 million (1.6%) compared to 2010. This increase was primarily due to $5.9 million in interest expense associated with the issuance of new long-term debt, $0.7 million associated with settlements and changes in tax positions from prior periods, $0.6 million associated with losses on interest rate swaps on senior notes, and $0.5 million associated with an affiliate loan related to STR in the first quarter 2011. These increases were partially offset by $5.9 million of additional capitalized interest associated with the construction of Plant Cleveland and Plant Nacogdoches and a $1.1 million decrease as the result of an early redemption of senior notes.

Loss on Extinguishment of Debt

In December 2011, the Company recorded a loss of $19.8 million in connection with the early redemption of senior notes primarily related to the payment of a make-whole premium.

Other Income (Expense), Net

In 2012, other income (expense), net increased $0.2 million compared to 2011. This increase was primarily due to increased earnings of STR, which resulted in a larger allocation of earnings to noncontrolling interest.

In 2011, other income (expense), net decreased $1.2 million compared to 2010. This decrease was primarily due to the reclassification from accumulated other comprehensive income (AOCI) of an interest rate hedge associated with the early redemption of senior notes in 2011 and profit recognized in 2010 on the construction contract with the Orlando Utilities Commission whereby the Company provided engineering, procurement, and construction services to build a combined cycle unit.

Income Taxes

In 2012, income taxes increased $16.7 million (22.1%) compared to 2011. This increase was primarily due to an $11.9 million increase associated with higher pre-tax earnings and a $9.3 million increase in Alabama state income taxes due to a decrease in the state income tax deduction for federal income taxes paid, partially offset by a $2.2 million decrease due to the conclusion of prior year Internal Revenue Service (IRS) audits and a $1.7 million decrease related to an increase in tax benefit from investment tax credits (ITCs) compared to 2011.

In 2011, income taxes increased $0.5 million (0.7%) compared to 2010. This increase was primarily due to a $12.4 million increase associated with higher pre-tax earnings, a $5.0 million increase due to reduced tax benefit from the impact of ITCs associated with the construction of Plant Nacogdoches and Plant Cimarron, and a $2.1 million increase due to the loss of the production activities deduction. These increases were partially offset by a $14.5 million decrease associated with the application of a lower composite tax rate and a $3.7 million decrease related to higher than expected future utilization of net operating losses in the State of New Mexico.

Effects of Inflation

The Company is party to long-term contracts reflecting market-based rates, including inflation expectations. Any adverse effect of inflation on the Company's results of operations has not been substantial in recent years.

FUTURE EARNINGS POTENTIAL

General

The results of operations for the past three years are not necessarily indicative of future earnings potential. The level of the Company's future earnings depends on numerous factors that affect the opportunities, challenges, and risks of the Company's competitive wholesale business. These factors include: the Company's ability to achieve sales growth while containing costs; regulatory matters; creditworthiness of customers; total generating capacity available in the Company's target market areas; the successful remarketing of capacity as current contracts expire; and the Company's ability to execute its acquisition strategy and to construct generating facilities.

Other factors that could influence future earnings include weather, demand, generation patterns, and operational limitations.

Power Sales Agreements

The Company's sales are primarily through long-term PPAs. The Company is working to maintain and expand its share of the wholesale market. The Company expects that demand for capacity will begin to develop within some of its existing market areas beginning in the 2014-2016 timeframe.

The Company's PPAs consist of two types of agreements. The first type, referred to as a unit or block sale, is a customer purchase from a dedicated plant unit where all or a portion of the generation from that unit is reserved for that customer. The Company typically has the ability to serve the unit or block sale customer from an alternate resource. The second type, referred to as requirements service, provides that the Company serve the customer's capacity and energy requirements from a combination of the customer's own generating units and from Company resources not dedicated to serve unit or block sales. The Company has rights to purchase power provided by the requirements customers' resources when economically viable.

The Company has entered into the following PPAs over the past three years:

	Date	MWs	Plant	Contract Term
2012				
Nevada Power Company[a]	June 2012	20	Apex	7/12-12/37[b]
Jackson Electric Membership Corporation (EMC)	September 2012	65[c]	Franklin	1/16-12/35
GreyStone Power Corporation	September 2012	40[c]	Franklin	1/16-12/35
Nevada Power Company[d]	September 2012	30	Spectrum	6/13[d]-12/38[b]
Progress Energy Carolinas, Inc.[e]	October 2012	2.5	Granville	10/12-10/32
Cobb EMC	December 2012	100	Franklin	1/16-12/22
Cobb EMC	December 2012	225	Dahlberg	1/16-12/22
Cobb EMC	December 2012	108[f]	Unassigned	1/16-12/22
2011				
Georgia Power Company[g]	June 2011	75	Dahlberg	1/15-5/30
Georgia Power Company[g]	June 2011	625	Harris[h]	6/15-5/30
Georgia Power Company[g]	June 2011	298	Addison	1/15-5/30
Morgan Stanley Capital Group	August 2011	250	Franklin	1/16-12/25
Tampa Electric Company	December 2011	160	Oleander	1/13-12/15[i]
2010				
Tri State Generation and Transmission Association, Inc.[j]	March 2010	30	Cimarron	12/10-11/35
City of Seneca	June 2010	30[f]	Unassigned	7/10-6/15
Georgia EMCs[k]	October 2010[k]	423[f]	Unassigned	1/15-12/27[k]

(a) Contract assumed through the Apex acquisition on June 29, 2012.
(b) These agreements commence on the operation date and continue for a period of 25 years from January 1 immediately following the commercial operation date.
(c) These agreements, signed on September 7, 2012, have an option to reduce the amount by 5MWs.
(d) Contract assumed through the Spectrum acquisition on September 28, 2012. Commercial operation of the Spectrum solar facility is expected to begin in mid-2013.
(e) Contract assumed through the Granville acquisition on October 16, 2012.
(f) Represents estimated average annual capacity purchases.
(g) These agreements were approved by the Georgia Public Service Commission on March 20, 2012 and accepted by the FERC on November 21, 2012.
(h) This agreement is contracted with Plant Franklin from June 2015 through December 2015.
(i) This agreement, signed on December 16, 2011, has an option for extension which, if signed by July 1, 2013, would extend the term to December 2017.
(j) Contract assumed through the Cimarron acquisition in March 2010.
(k) These agreements, signed in October and December 2010, are extensions of current agreements with 11 Georgia EMCs. Nine agreements were extended from 2015 through 2024, one agreement was extended from 2018 through 2027, and one agreement was extended from 2018 through 2024.

The Company has PPAs with some of Southern Company's traditional operating companies, other investor owned utilities, independent power producers, municipalities, electric cooperatives, and an energy marketing firm. Although some of the Company's PPAs are with the traditional operating companies, the Company's generating facilities are not in the traditional operating companies' regulated rate bases, and the Company is not able to seek recovery from the traditional operating companies' ratepayers for construction, repair, environmental, or maintenance costs. The Company expects that the capacity payments in the PPAs will produce sufficient cash flows to cover costs, pay debt service, and provide an equity return. However, the Company's overall profit will depend on numerous factors, including efficient operation of its generating facilities and demand under the Company's PPAs.

As a general matter, existing PPAs provide that the purchasers are responsible for either procuring the fuel or reimbursing the Company for the cost of fuel relating to the energy delivered under such PPAs. To the extent a particular generating facility does not meet the operational requirements contemplated in the PPAs, the Company may be responsible for excess fuel costs. With respect to fuel transportation risk, most of the Company's PPAs provide that the counterparties are responsible for transporting the fuel to the particular generating facility.

Fixed and variable operation and maintenance costs will be recovered through capacity charges based on dollars-per-kilowatt year or energy charges based on dollars-per-MW hour. In general, the Company has long-term service contracts with General Electric International, Inc., Siemens Electric, Inc., and First Solar, Inc. to reduce its exposure to certain operation and maintenance costs relating to such vendors' applicable equipment.

Many of the Company's PPAs have provisions that require the posting of collateral or an acceptable substitute guarantee in the event that Standard & Poor's Rating Services, a division of The McGraw Hill Companies, Inc. (S&P) or Moody's Investors Service, Inc. (Moody's) downgrades the credit ratings of the counterparty to an unacceptable credit rating or if the counterparty is not rated or fails to maintain a minimum coverage ratio. The PPAs are expected to provide the Company with a stable source of revenue during their respective terms.

The Company has entered into long-term power sales agreements for an average of 77% of its available capacity for the next five years and 70% of its available capacity for the next 10 years.

Environmental Matters

The Company's operations are subject to extensive regulation by state and federal environmental agencies under a variety of statutes and regulations governing environmental media, including air, water, and land resources. Applicable statutes include the Clean Air Act; the Clean Water Act; the Comprehensive Environmental Response, Compensation, and Liability Act; the Resource Conservation and Recovery Act; the Toxic Substances Control Act; the Emergency Planning & Community Right-to-Know Act; the Endangered Species Act; and related federal and state regulations. Compliance with possible additional federal or state legislation or regulations related to global climate change, air quality, water quality, or other environmental and health concerns could also significantly affect the Company.

New environmental legislation or regulations, such as requirements related to greenhouse gases or changes to existing statutes or regulations, could affect many areas of the Company's operations. While the Company's PPAs generally contain provisions that permit charging the counterparty with some of the new costs incurred as a result of changes in environmental laws and regulations, the full impact of any such regulatory or legislative changes cannot be determined at this time.

Because the Company's units are newer gas-fired generating facilities, costs associated with environmental compliance for these facilities have been less significant than for similarly situated coal-fired generating facilities or older gas-fired generating facilities. Environmental, natural resource, and land use concerns, including the applicability of air quality limitations, the availability of water withdrawal rights, uncertainties regarding aesthetic impacts such as increased light or noise, and concerns about potential adverse health impacts can, however, increase the cost of siting and operating any type of future electric generating facility. The impact of such statutes and regulations on the Company cannot be determined at this time.

Climate Change Litigation

Kivalina Case

In 2008, the Native Village of Kivalina and the City of Kivalina filed a lawsuit in the U.S. District Court for the Northern District of California against several electric utilities (including Southern Company), several oil companies, and a coal company. The plaintiffs allege that the village is being destroyed by erosion allegedly caused by global warming that the plaintiffs attribute to emissions of greenhouse gases by the defendants. The plaintiffs assert claims for public and private nuisance and contend that some of the defendants (including Southern Company) acted in concert and are therefore jointly and severally liable for the plaintiffs' damages. The suit seeks damages for lost property values and for the cost of relocating the village, which is alleged to be $95 million to $400 million. In 2009, the U.S. District Court for the Northern District of California granted the defendants' motions to dismiss the case. On September 21, 2012, the U.S. Court of Appeals for the Ninth Circuit upheld the U.S. District Court for the Northern District of California's dismissal of the case. On November 27, 2012, the U.S. Court of Appeals for the Ninth Circuit denied the plaintiffs' request for review of the decision. On February 25, 2013, the plaintiffs filed a petition for writ of certiorari with the U.S. Supreme Court. Southern Company believes that these claims are without merit. The ultimate outcome of this matter cannot be determined at this time.

Hurricane Katrina Case

In 2005, immediately following Hurricane Katrina, a lawsuit was filed in the U.S. District Court for the Southern District of Mississippi by Ned Comer on behalf of Mississippi residents seeking recovery for property damage and personal injuries caused by Hurricane Katrina. In 2006, the plaintiffs amended the complaint to include Southern Company and many other electric utilities, oil companies, chemical companies, and coal producers. The plaintiffs allege that the defendants contributed to climate change, which contributed to the intensity of Hurricane Katrina. In 2007, the U.S. District Court for the Southern District of Mississippi dismissed the case. On appeal to the U.S. Court of Appeals for the Fifth Circuit, a three-judge panel reversed the U.S. District Court for the Southern District of Mississippi, holding that the case could proceed, but, on rehearing, the full U.S. Court of Appeals for the Fifth Circuit dismissed the plaintiffs' appeal, resulting in reinstatement of the decision of the U.S. District Court for the Southern District of Mississippi in favor of the defendants. In May 2011, the plaintiffs filed an amended version of their class action complaint, arguing that the earlier dismissal was on procedural grounds and under Mississippi law the plaintiffs have a right to re-file. The amended complaint was also filed against numerous chemical, coal, oil, and utility companies, including the Company. On March 20, 2012, the U.S. District Court for the Southern District of Mississippi dismissed the plaintiffs' amended complaint. On April 16, 2012, the plaintiffs appealed the case to the U.S. Court of Appeals for the Fifth Circuit. The Company believes that these claims are without merit. The ultimate outcome of this matter cannot be determined at this time.

Environmental Statutes and Regulations

Air Quality

Revisions to the National Ambient Air Quality Standard for nitrogen dioxide (NO_2), which established a new one-hour standard, became effective in 2010. On February 29, 2012, the new NO_2 standard became effective. The EPA designated the entire country as "unclassifiable/attainment" under the new standard, with no nonattainment areas designated. However, the new NO_2 standard could result in significant additional compliance and operational costs for units that require new source permitting.

On January 31, 2013, the Environmental Protection Agency (EPA) published the final Industrial Boiler Maximum Achievable Control Technology (IB MACT) rule establishing emissions limits and/or work practice standards for various hazardous air pollutants emitted from industrial boilers, including biomass boilers and start-up boilers. Compliance for existing sources will be required by early 2016. Compliance for new sources will begin upon startup.

Each of the states in which the Company has fossil generation is subject to the requirements of the Clean Air Interstate Rule (CAIR), which calls for phased reductions in sulfur dioxide and nitrogen oxide emissions from power plants in 28 eastern states. In 2008, the U.S. Court of Appeals for the District of Columbia Circuit issued decisions invalidating CAIR, but left CAIR compliance requirements in place while the EPA developed a new rule. In August 2011, the EPA adopted the Cross State Air Pollution Rule (CSAPR) to replace CAIR effective January 1, 2012. However, in December 2011, the U.S. Court of Appeals for the District of Columbia Circuit stayed the rule, and on August 21, 2012, vacated CSAPR in its entirety and directed the EPA to continue to administer CAIR pending the EPA's development of a valid replacement. On January 24, 2013, the U.S. Court of Appeals for the District of Columbia Circuit denied requests by the EPA and other parties for rehearing.

On August 29, 2012, the EPA published proposed revisions to the New Source Performance Standard (NSPS) for Stationary Combustion Turbines (CTs). If finalized as proposed, the revisions would apply the NSPS to all new, reconstructed, and modified CTs (including CTs at combined cycle units), during all periods of operation, including startup and shutdown, and alter the criteria for determining when an existing CT has been reconstructed.

On February 12, 2013, the EPA proposed a rule that would require certain states to revise the provisions of their State Implementation Plans (SIPs) relating to the regulation of excess emissions at industrial facilities, including fossil fuel-fired generating facilities, during periods of startup, shut-down, or malfunction (SSM). The EPA proposes a determination that the SSM provisions in the SIPs for 36 states (including Alabama, Florida, Georgia, and North Carolina) do not meet the requirements of the Clean Air Act and must be revised within 18 months of the date on which the EPA publishes the final rule. If finalized as proposed, this new requirement could result in significant additional compliance and operational costs.

The Company has developed and continually updates a comprehensive environmental compliance strategy to assess compliance obligations associated with the existing and new environmental requirements discussed above. The impacts of the NO_2 standards, IB MACT rule, CAIR and any future replacement rule, the NSPS for CTs, and the SSM rule on the Company cannot be determined at this time and will depend on the specific provisions of recently finalized and future rules, the resolution of pending and future legal challenges, and the development and implementation of rules at the state level. These regulations could result in additional compliance costs that could affect results of operations, cash flows, and financial condition if such costs are not

recovered through PPAs. Further, higher costs that are recovered through regulated rates at other utilities could contribute to reduced demand for electricity, which could negatively impact results of operations, cash flows, and financial condition.

Water Quality

In April 2011, the EPA published a proposed rule that establishes standards for reducing effects on fish and other aquatic life caused by cooling water intake structures at existing power plants and manufacturing facilities. The rule also addresses cooling water intake structures for new units at existing facilities. Compliance with the proposed rule could require changes to existing cooling water intake structures at certain of the Company's generating facilities, and new generating units constructed at existing plants would be required to install closed cycle cooling towers. The EPA has entered into an amended settlement agreement to extend the deadline for issuing a final rule until June 27, 2013. If finalized as proposed, some of the Company's facilities may be subject to additional capital expenditures and compliance costs. Also, results of operations, cash flows, and financial condition could be impacted if such costs are not recovered through PPAs. Based on a preliminary assessment of the impact of the proposed rules, the Company estimates compliance costs to be immaterial. The ultimate outcome of this rulemaking will depend on the final rule and the outcome of any legal challenges and cannot be determined at this time.

The EPA has announced its determination that revision of the current effluent guidelines for steam electric power plants is warranted and has stated that it intends to propose such revisions by April 2013 and finalize the revisions by May 2014. New advanced wastewater treatment requirements are expected and may result in the installation of additional controls on certain of the Company's facilities, which could result in additional capital expenditures and compliance costs. The impact of the revised guidelines will depend on the specific technology requirements of the final rule and, therefore, cannot be determined at this time.

Global Climate Issues

The EPA currently regulates greenhouse gases under the Prevention of Significant Deterioration and Title V operating permit programs of the Clean Air Act. In addition, over the past several years, the U.S. Congress has considered many proposals to reduce greenhouse gas emissions, mandate renewable or clean energy, and impose energy efficiency standards. Such proposals are expected to continue to be considered by the U.S. Congress. International climate change negotiations under the United Nations Framework Convention on Climate Change are also continuing.

On April 13, 2012, the EPA published proposed regulations to establish standards of performance for greenhouse gas emissions from new fossil fuel steam electric generating units. The EPA has also announced plans to develop federal guidelines for states to establish greenhouse gas emissions performance standards for existing sources. The impact of this rulemaking will depend on the scope and specific requirements of the final rule and the outcome of any legal challenges and, therefore, cannot be determined at this time.

Although the outcome of federal, state, and international initiatives cannot be determined at this time, additional restrictions on the Company's greenhouse gas emissions at the federal or state level could result in additional compliance costs, including capital expenditures. Additional compliance costs could affect results of operations, cash flows, and financial condition if such costs are not recovered through PPAs. Further, higher costs that are recovered through regulated rates at other utilities could contribute to reduced demand for electricity, which could negatively impact results of operations, cash flows, and financial condition.

The EPA's greenhouse gas reporting rule requires annual reporting of carbon dioxide equivalent emissions in metric tons for a company's operational control of facilities. Based on ownership or financial control of facilities, the Company reported 2011 greenhouse gas emissions of approximately 10 million metric tons of carbon dioxide equivalent. The preliminary estimate of the Company's 2012 greenhouse gas emissions on the same basis is approximately 12 million metric tons of carbon dioxide equivalent. The level of greenhouse gas emissions from year to year will depend on the level of generation and mix of fuel sources, which is determined primarily by demand, the unit cost of fuel consumed, and the availability of generating units.

Income Tax Matters

Investment Tax Credits

In February 2009, President Obama signed into law the American Recovery and Reinvestment Act of 2009 (ARRA). Major tax incentives in the ARRA included renewable energy incentives. The Company received ITCs under the renewable energy incentives related to Plant Nacogdoches, Plant Cimarron, Plant Apex, and Plant Granville which have had a material impact on cash flows and net income. On January 2, 2013, the American Taxpayer Relief Act of 2012 (ATRA) was signed into law. The ATRA retroactively extended several renewable energy incentives through 2013, including extending investment tax credits for biomass projects which begin construction before January 1, 2014. See Note 1 to the financial statements under "Investment Tax Credits" and Note 5 to the financial statements under "Effective Tax Rate" for additional information.

Bonus Depreciation

In 2010, the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010 (Tax Relief Act) was signed into law. Major tax incentives in the Tax Relief Act include 100% bonus depreciation for property placed in service after September 8, 2010 and through 2011 (and for certain long-term production-period projects placed in service in 2012) and 50% bonus depreciation for property placed in service in 2012 (and for certain long-term production-period projects to be placed in service in 2013), which will have a positive impact on the future cash flows of the Company through 2013.

The ATRA retroactively extended several tax credits through 2013 and extended 50% bonus depreciation for property to be placed in service in 2013 (and for certain long-term production-period projects to be placed in service in 2014). The extension of 50% bonus depreciation will have a positive impact on the future cash flows of the Company through 2014.

Due to the significant amount of estimated bonus depreciation for 2013, tax credit utilization will be deferred. Consequently, the Company's positive cash flow benefit is estimated to be between $105 million and $115 million in 2013. See Note 5 to the financial statements under "Current and Deferred Income Taxes" for additional information.

Acquisitions

Granville Solar, LLC Acquisition

On October 16, 2012, the Company, through STR, acquired all of the outstanding membership interests of Granville from Sun Edison, LLC, the original developer of the project. Granville constructed and owns a 2.5-MW solar photovoltaic facility in Oxford, North Carolina. The solar facility began commercial operation on October 28, 2012. The output of the plant is contracted under a 20-year PPA with Progress Energy Carolinas, Inc. that began in October 2012. See Note 2 to the financial statements for additional information.

Spectrum Nevada Solar, LLC Acquisition

On September 28, 2012, the Company, through STR, acquired all of the outstanding membership interests of Spectrum from Sun Edison, LLC, the original developer of the project. Spectrum is constructing a 30-MW solar photovoltaic facility in North Las Vegas, Nevada. The solar facility is expected to begin commercial operation in mid-2013. The output of the plant is contracted under a 25-year PPA with Nevada Power Company, a subsidiary of NV Energy, Inc., that will begin in 2013. See Note 2 to the financial statements for additional information.

Apex Nevada Solar, LLC Acquisition

On June 29, 2012, the Company, through STR, acquired all of the outstanding membership interests of Apex from Sun Edison, LLC, the original developer of the project. Apex constructed and owns a 20-MW solar photovoltaic facility in North Las Vegas, Nevada. The solar facility began commercial operation on July 21, 2012. The output of the plant is contracted under a 25-year PPA with Nevada Power Company, a subsidiary of NV Energy, Inc., that began in July 2012. See Note 2 to the financial statements for additional information.

Other Matters

The Company is involved in various other matters being litigated and regulatory matters that could affect future earnings. In addition, the Company is subject to certain claims and legal actions arising in the ordinary course of business. The Company's business activities are subject to extensive governmental regulation related to public health and the environment, such as regulation of air emissions and water discharges. Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements such as air quality and water standards, has increased generally throughout the U.S. In particular, personal injury, property damage, and other claims for damages alleged to have been caused by carbon dioxide and other emissions and alleged exposure to hazardous materials, and/or requests for injunctive relief in connection with such matters, have become more frequent.

The ultimate outcome of such pending or potential litigation against the Company cannot be predicted at this time; however, for current proceedings not specifically reported herein or in Note 3 to the financial statements, management does not anticipate that the ultimate liabilities, if any, arising from such current proceedings would have a material effect on the Company's financial statements. See Note 3 to the financial statements for a discussion of various other contingencies and other matters being litigated which may affect future earnings potential.

ACCOUNTING POLICIES

Application of Critical Accounting Policies and Estimates

The Company prepares its consolidated financial statements in accordance with generally accepted accounting principles (GAAP). Significant accounting policies are described in Note 1 to the financial statements. In the application of these policies, certain estimates are made that may have a material impact on the Company's results of operations and related disclosures. Different assumptions and measurements could produce estimates that are significantly different from those recorded in the financial statements. Senior management has reviewed and discussed the following critical accounting policies and estimates with the Audit Committee of Southern Company's Board of Directors.

Revenue Recognition

The Company's revenue recognition depends on appropriate classification and documentation of transactions in accordance with GAAP. In general, the Company's power sale transactions can be classified in one of four categories: leases, non-derivatives or normal sale derivatives, derivatives designated as cash flow hedges, and derivatives not designated as hedges. For more information on derivative transactions, see FINANCIAL CONDITION AND LIQUIDITY – "Market Price Risk" herein and Notes 1 and 9 to the financial statements. The Company's revenues are dependent upon significant judgments used to determine the appropriate transaction classification, which must be documented upon the inception of each contract.

Lease Transactions

The Company considers the following factors to determine whether the sales contract is a lease:

- Assessing whether specific property is explicitly or implicitly identified in the agreement;
- Determining whether the fulfillment of the arrangement is dependent on the use of the identified property; and
- Assessing whether the arrangement conveys to the purchaser the right to use the identified property.

If the contract meets the above criteria for a lease, the Company performs further analysis as to whether the lease is classified as operating or capital. All of the Company's power sales contracts classified as leases are accounted for as operating leases and revenue is recognized on a straight-line basis over the term of the contract.

Non-Derivative and Normal Sale Derivative Transactions

If the sales contract is not considered a lease, the Company further considers the following factors to determine proper transaction classification:

- Assessing whether a sales contract meets the definition of a derivative;
- Assessing whether a sales contract meets the definition of a capacity contract;
- Assessing the probability at inception and throughout the term of the individual contract that the contract will result in physical delivery; and
- Ensuring that the contract quantities do not exceed available generating capacity (including purchased capacity).

Contracts that do not meet the definition of a derivative or are designated as normal sales (i.e. capacity contracts which provide for the sale of electricity that involve physical delivery in quantities within the Company's available generating capacity) are exempt from fair value accounting in accordance with GAAP. As a result, such transactions are accounted for as executory contracts. The related capacity revenue is recognized on an accrual basis in amounts equal to the lesser of the cumulative levelized amount or the cumulative amount billable under the contract over the respective contract periods. Revenues are recorded on a gross or net basis in accordance with GAAP. Contracts recorded on the accrual basis represented the majority of the Company's operating revenues for the years ended December 31, 2012, 2011, and 2010.

Cash Flow Hedge Transactions

The Company further considers the following in designating other derivative contracts for the sale of electricity as cash flow hedges of anticipated sale transactions:

- Identifying the hedging instrument, the hedged transaction, and the nature of the risk being hedged; and
- Assessing hedge effectiveness at inception and throughout the contract term.

These contracts are marked to market through AOCI over the life of the contract. Realized gains and losses are then recognized in revenues as incurred.

Mark-to-Market Transactions

Contracts for sales and purchases of electricity, which meet the definition of a derivative and that either do not qualify or are not designated as normal sales or as cash flow hedges, are marked-to-market and recorded directly through net income.

Impairment of Long Lived Assets and Intangibles

The Company's investments in long-lived assets are primarily generation assets, whether in service or under construction. The Company's intangible assets consist of acquired PPAs that are amortized over the term of the PPAs and goodwill resulting from acquisitions. The Company evaluates the carrying value of these assets in accordance with accounting standards whenever indicators of potential impairment exist, or annually in the case of goodwill. Examples of impairment indicators could include significant changes in construction schedules, current period losses combined with a history of losses or a projection of continuing losses, a significant decrease in market prices, and the inability to remarket generating capacity for an extended period. If an indicator exists, the asset is tested for recoverability by comparing the asset carrying value to the sum of the undiscounted expected future cash flows directly attributable to the asset. A high degree of judgment is required in developing estimates related to these evaluations, which are based on projections of various factors, including the following:

- Future demand for electricity based on projections of economic growth and estimates of available generating capacity;
- Future power and natural gas prices, which have been quite volatile in recent years; and
- Future operating costs.

Acquisition Accounting

The Company acquires generation assets as part of its overall growth strategy. The Company accounts for business acquisitions from non-affiliates as business combinations utilizing the acquisition method in accordance with GAAP. Accordingly, the Company has included these operations in the consolidated financial statements from the respective date of acquisition. The purchase price, including contingent consideration, if any, of each acquisition was allocated based on the fair value of the identifiable assets and liabilities. Assets acquired that do not meet the definition of a business in accordance with GAAP are accounted for as asset acquisitions. The purchase price of each asset acquisition was allocated based on the relative fair value of assets acquired. Any due diligence or transition costs incurred by the Company for successful or potential acquisitions have been expensed as incurred.

Contingent Obligations

The Company is subject to a number of federal and state laws and regulations, as well as other factors and conditions that subject it to environmental, litigation, income tax, and other risks. See FUTURE EARNINGS POTENTIAL herein and Note 3 to the financial statements for more information regarding certain of these contingencies. The Company periodically evaluates its exposure to such risks and, in accordance with GAAP, records reserves for those matters where a non-tax-related loss is considered probable and reasonably estimable and records a tax asset or liability if it is more likely than not that a tax position will be sustained. The adequacy of reserves can be significantly affected by external events or conditions that can be unpredictable; thus, the ultimate outcome of such matters could materially affect the Company's financial statements.

Depreciation

Depreciation of the original cost of assets is computed under the straight-line method and applies a composite depreciation rate based on the assets' estimated useful lives determined by management. The primary assets in property, plant, and equipment are power plants, which have estimated composite lives ranging from 21 to 35 years. These lives reflect a weighted average of the significant components (retirement units) that make up the plants. Key judgments impacting the estimated lives of component parts include estimates of run-hours and starts which can impact the future utility of these components. The Company reviews its estimated useful lives and salvage values on an ongoing basis. The results of these reviews could result in changes which could have a material impact on net income in the near term.

When property subject to composite depreciation is retired or otherwise disposed of in the normal course of business, its cost is charged to accumulated depreciation. For other property dispositions, the applicable cost and accumulated depreciation is removed from the accounts and a gain or loss is recognized.

Investment Tax Credits

Under the ARRA, certain construction costs related to Plant Nacogdoches, Plant Cimarron, Plant Apex, Plant Spectrum, and Plant Granville are eligible for ITCs. A high degree of judgment is required in determining which construction expenditures qualify for ITCs. See Note 1 to the financial statements under "Investment Tax Credits" for additional information.

FINANCIAL CONDITION AND LIQUIDITY

Overview

The Company's financial condition remained stable at December 31, 2012. The Company intends to continue to monitor its access to short-term and long-term capital markets as well as its bank credit arrangements as needed to meet its future capital and liquidity needs. See "Sources of Capital" herein for additional information on lines of credit.

Net cash provided from operating activities totaled $573.1 million in 2012, an increase of $160.8 million as compared to 2011. This increase was primarily due to an increase in deferred income tax, partially offset by a decrease in cash received for ITCs and an adjustment for the loss on extinguishment of debt in 2011. Net cash provided from operating activities totaled $412.4 million in 2011, an increase of $85.5 million compared to 2010. This increase was primarily due to an increase in ITCs received in 2011.

Net cash used for investing activities totaled $332.5 million, $328.4 million, and $408.1 million in 2012, 2011, and 2010, respectively. Net cash used for investing activities in 2012 was primarily due to the Apex, Spectrum, and Granville acquisitions, construction spending on Plant Nacogdoches and Plant Cleveland, and payments pursuant to long-term service agreements. Net cash used for investing activities in 2011 was primarily due to construction spending on Plant Nacogdoches and Plant Cleveland. Net cash used for investing activities in 2010 was primarily due to construction spending on Plant Nacogdoches and Plant Cleveland and the acquisition of Plant Cimarron.

Net cash used for financing activities totaled $229.0 million and $81.3 million in 2012 and 2011, respectively. Net cash provided from financing activities totaled $88.3 million in 2010. Net cash used for financing activities in 2012 was primarily due to payment of common stock dividends and a decrease in notes payable. Net cash used for financing activities in 2011 was primarily due to a decrease in notes payable. Net cash provided from financing activities in 2010 was primarily due to an increase in notes payable. Fluctuations in cash flow from financing activities vary year to year based on capital needs and the maturity or redemption of securities.

Significant asset changes in the balance sheet during 2012 include an increase in property, plant, and equipment, primarily due to the Apex, Spectrum, and Granville acquisitions and an increase in prepaid service agreements-current, primarily due to the timing of plant outages.

Significant liability and stockholder's equity changes in the balance sheet during 2012 include an increase in accumulated deferred income taxes due to bonus depreciation and an increase in deferred investment tax credits due to additional spending on Plant Nacogdoches and the Apex and Granville acquisitions. This increase was partially offset by a decrease in notes payable to non-affiliates due to the timing of operating cash flows.

Sources of Capital

The Company may use operating cash flows, external funds, or equity capital or loans from Southern Company to finance any new projects, acquisitions, and ongoing capital requirements. The Company expects to generate external funds from the issuance of unsecured senior debt and commercial paper or utilization of credit arrangements from banks. However, the amount, type, and timing of any future financings, if needed, will depend upon prevailing market conditions, regulatory approval, and other factors.

The issuance of securities by the Company is subject to regulatory approval by the FERC. Additionally, with respect to the public offering of securities, the Company files registration statements with the Securities and Exchange Commission (SEC) under the Securities Act of 1933, as amended (1933 Act). The amounts of securities authorized by the FERC, as well as the amounts registered under the 1933 Act, are continuously monitored and appropriate filings are made to ensure flexibility in the capital markets.

The Company's current liabilities frequently exceed current assets due to the use of short-term debt as a funding source, as well as cash needs, which can fluctuate significantly due to the seasonality of the business.

To meet liquidity and capital resource requirements, the Company had at December 31, 2012 cash and cash equivalents of approximately $28.6 million and a committed credit facility of $500 million (Facility) expiring in 2016. As of December 31, 2012, the total amount available under the Facility was $500 million. The Facility does not contain a material adverse change clause applicable to borrowing.

The Facility contains a covenant that limits the ratio of debt to capitalization (each as defined in the Facility) to a maximum of 65% and contains a cross default provision that is restricted only to indebtedness of the Company. The Company is currently in compliance with all covenants in the Facility.

Proceeds from the Facility may be used for working capital and general corporate purposes as well as liquidity support for the Company's commercial paper program. See Note 6 to the financial statements under "Bank Credit Arrangements" for additional information.

The Company's commercial paper program is used to finance acquisition and construction costs related to electric generating facilities and for general corporate purposes.

Details of short-term borrowings were as follows:

	Short-term Debt at the End of the Period		Short-term Debt During the Period [a]		
	Amount Outstanding	Weighted Average Interest Rate	Average Outstanding	Weighted Average Interest Rate	Maximum Amount Outstanding
	(in millions)		*(in millions)*		*(in millions)*
December 31, 2012:					
Commercial paper	**$ 71**	**0.5%**	**$ 170**	**0.5%**	**$ 309**
December 31, 2011:					
Commercial paper	$ 180	0.5%	$ 175	0.4%	$ 305
December 31, 2010:					
Commercial paper	$ 204	0.4%	$ 169	0.4%	$ 259

(a) Average and maximum amounts are based upon daily balances during the twelve-month periods ended December 31, 2012, 2011, and 2010.

Management believes that the need for working capital can be adequately met by utilizing the commercial paper program, the line of credit, and cash.

Financing Activities

During 2012, the Company prepaid $2.5 million on a long-term debt related to STR.

During 2012, the Company issued a $4.1 million promissory note, due June 15, 2032, to TRE related to the financing of Apex.

During 2012, the Company issued a $0.9 million promissory note, due September 30, 2032, to TRE related to the financing of Spectrum.

During 2012, the Company issued a $0.5 million promissory note, due October 31, 2032, to TRE related to the financing of Granville.

In addition to any financings that may be necessary to meet capital requirements and contractual obligations, the Company plans to continue, when economically feasible, a program to retire higher-cost securities and replace these obligations with lower-cost capital if market conditions permit.

Credit Rating Risk

The Company does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. There are certain contracts that could require collateral, but not accelerated payment, in the event of a credit rating change to BBB and Baa2, or BBB- and/or Baa3 or below. These contracts are for physical electricity purchases and sales, fuel transportation and storage, and energy price risk management.

The maximum potential collateral requirements under these contracts at December 31, 2012 were as follows:

Credit Ratings	Maximum Potential Collateral Requirements
	(in millions)
At BBB and Baa2	$ 9
At BBB- and/or Baa3	487
Below BBB- and/or Baa3	1,226

Included in these amounts are certain agreements that could require collateral in the event that one or more Southern Company system power pool participants has a credit rating change to below investment grade. Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. Additionally, any credit rating downgrade could impact the Company's ability to access capital markets, particularly the short-term debt market.

In addition, through the acquisition of Plant Rowan, the Company assumed a PPA with North Carolina Municipal Power Agency No. 1 that could require collateral, but not accelerated payment, in the event of a downgrade of the Company's credit. The PPA requires credit assurances without stating a specific credit rating. The amount of collateral required would depend upon actual losses, if any, resulting from a credit downgrade.

Market Price Risk

The Company is exposed to market risks, including changes in interest rates, certain energy-related commodity prices, and, occasionally, currency exchange rates. To manage the volatility attributable to these exposures, the Company takes advantage of natural offsets and enters into various derivative transactions for the remaining exposures pursuant to the Company's policies in areas such as counterparty exposure and risk management practices. The Company's policy is that derivatives are to be used primarily for hedging purposes and mandates strict adherence to all applicable risk management policies. Derivative positions are monitored using techniques including, but not limited to, market valuation, value at risk, stress testing, and sensitivity analysis.

At December 31, 2012, the Company had $4.1 million of long-term variable debt outstanding. The effect on annualized interest expense related to long-term debt if the Company sustained a 100 basis point change in interest rates is immaterial. Since a significant portion of outstanding indebtedness bears interest at fixed rates, the Company is not aware of any facts or circumstances that would significantly affect exposure on existing indebtedness in the near term. However, the impact on future financing costs cannot be determined at this time.

Because energy from the Company's facilities is primarily sold under long-term PPAs with tolling agreements and provisions shifting substantially all of the responsibility for fuel cost to the counterparties, the Company's exposure to market volatility in commodity fuel prices and prices of electricity is generally limited. However, the Company has been and may continue to be exposed to market volatility in energy-related commodity prices as a result of sales of uncontracted generating capacity.

The changes in fair value of energy-related derivative contracts for the years ended December 31 were as follows:

	2012 Changes	2011 Changes
	Fair Value	
	(in millions)	
Contracts outstanding at the beginning of the period, assets (liabilities), net	$ (9.2)	$ (3.5)
Contracts realized or settled	15.6	5.6
Current period changes[(a)]	(5.6)	(11.3)
Contracts outstanding at the end of the period, assets (liabilities), net	$ 0.8	$ (9.2)

(a) Current period changes also include changes in the fair value of new contracts entered into during the period, if any.

For the year ended December 31, 2012, there was a $10.0 million increase in the fair value positions of the energy-related derivative contracts associated with both power and natural gas positions. For the year ended December 31, 2011, there was a $5.7 million decrease in the fair value positions of the energy related derivative contracts associated with both power and natural gas positions.

The changes were attributable to both the volume and the prices of power and natural gas as follows:

	December 31, 2012	December 31, 2011
Power – net purchased or (sold)		
Megawatt hours (MWH) (in millions)	—	0.1
Weighted average contract cost per MWH above (below) market prices (in dollars)	$ —	$ (1.04)
Natural gas net purchased		
Commodity – million British thermal unit (mmBtu)	**5.0**	8.3
Commodity – weighted average contract cost per mmBtu above (below) market prices (in dollars)	$ **(0.02)**	$ 1.18

At December 31, the net fair value of energy-related derivative contracts by hedge designation was reflected in the financial statements as follows:

Asset (Liability) Derivatives	**2012**	2011
	(in millions)	
Cash flow hedges	$ —	$ (0.8)
Not designated	**0.8**	(8.4)
Total fair value	$ **0.8**	$ (9.2)

Gains and losses on energy-related derivatives used by the Company to hedge anticipated purchases and sales are initially deferred in AOCI before being recognized in income in the same period as the hedged transaction. Gains and losses on energy-related derivative contracts that are not designated or fail to qualify as hedges are recognized in the statements of income as incurred.

For the Company's energy-related derivatives not designated as hedging instruments, a substantial portion of the pre-tax realized and unrealized gains and losses is associated with hedging fuel price risk of certain PPA customers and has no impact on net income or on fuel expense as presented in the Company's statements of income. As a result, the pre-tax effects of energy-related derivatives not designated as hedging instruments on the Company's statements of income were immaterial for the years ended December 31, 2012, 2011, and 2010.

The Company uses over-the-counter contracts that are not exchange traded but are fair valued using prices which are market observable, and thus fall into Level 2. See Note 8 to the financial statements for further discussion of fair value measurements. The maturities of the energy-related derivative contracts and the level of the fair value hierarchy in which they fall at December 31, 2012 were as follows:

	Fair Value Measurements December 31, 2012			
	Total	Maturity		
	Fair Value	Year 1	Years 2&3	Years 4&5
		(in millions)		
Level 1	$ —	$ —	$ —	$ —
Level 2	0.8	(0.3)	—	1.1
Level 3	—	—	—	—
Fair value of contracts outstanding at end of period	$ 0.8	$ (0.3)	$ —	$ 1.1

The Company is exposed to market price risk in the event of nonperformance by counterparties to energy-related derivative contracts. The Company only enters into agreements with counterparties that have investment grade credit ratings by S&P and Moody's or with counterparties who have posted collateral to cover potential credit exposure. Therefore, the Company does not anticipate market risk exposure from nonperformance by the counterparties. See Note 1 to the financial statements under "Financial Instruments" and Note 9 to the financial statements for additional information.

Capital Requirements and Contractual Obligations

The capital program of the Company is currently estimated to be $909.6 million for 2013, $751.8 million for 2014, and $735.7 million for 2015. These amounts include estimates for potential plant acquisitions and new construction as well as ongoing capital improvements and work to be performed under long-term service agreements. Planned expenditures for plant acquisitions may vary due to market opportunities and the Company's ability to execute its growth strategy. Actual construction costs may vary from these estimates because of changes in factors such as: business conditions; environmental statutes and regulations; FERC rules and regulations; load projections; legislation; the cost and efficiency of construction labor, equipment, and materials; project scope and design changes; and the cost of capital.

In addition, pursuant to an agreement with TRE, on or after November 25, 2015, TRE may require the Company to purchase its noncontrolling interest in STR at fair market value.

Other funding requirements related to obligations associated with scheduled maturities of long-term debt, as well as the related interest, leases, derivative obligations, and other purchase commitments are detailed in the contractual obligations table that follows. See Notes 1, 5, 6, 7, and 9 to the financial statements for additional information.

Contractual Obligations

	2013	2014-2015	2016-2017	After 2017	Uncertain Timing [c]	Total
			(in millions)			
Long-term debt[a] —						
Principal	$ —	$ 525.0	$ —	$ 779.1	$ —	$ 1,304.1
Interest	68.1	124.5	85.0	944.6	—	1,222.2
Financial derivative obligations[b]	0.7	0.6	—	—	—	1.3
Operating leases[c]	1.3	3.0	2.6	40.3	—	47.2
Unrecognized tax benefits[d]	—	—	—	—	2.9	2.9
Purchase commitments —						
Capital[e]	799.7	1,374.4	—	—	—	2,174.1
Fuel[f]	469.4	688.4	345.5	277.4	—	1,780.7
Purchased power[g]	50.4	105.1	77.4	164.3	—	397.2
Other[h]	51.7	184.9	142.0	534.1	—	912.7
Transmission agreements[i]	0.9	1.8	3.6	3.6	—	9.9
Total	$ 1,442.2	$ 3,007.7	$ 656.1	$ 2,743.4	$ 2.9	$ 7,852.3

(a) All amounts are reflected based on final maturity dates. The Company plans to retire higher-cost securities and replace these obligations with lower-cost capital if market conditions permit.

(b) For additional information, see Notes 1 and 9 to the financial statements.

(c) Operating lease commitments are subject to price escalation based on the Consumer Price Index for All Urban Consumers for the Plant Stanton Unit A land lease.

(d) The timing related to the realization of $2.9 million in unrecognized tax benefits in individual years beyond 12 months cannot be reasonably and reliably estimated due to uncertainties in the timing of the effective settlement of tax positions. See Note 5 to the financial statements under "Unrecognized Tax Benefits" for additional information.

(e) The Company provides estimated capital expenditures for a three-year period. Amounts represent current estimates of total expenditures, excluding capital expenditures covered under long-term service agreements.

(f) Primarily commitments to purchase, transport, and store natural gas fuel. Amounts reflected are based on contracted cost and may contain provisions for price escalation. Amounts reflected for natural gas purchase commitments are based on various indices at the time of delivery and have been estimated based on the New York Mercantile Exchange future prices at December 31, 2012.

(g) Purchased power commitments of $36.1 million in 2013, $74.4 million in 2014-2015, $77.4 million in 2016-2017, and $164.3 million after 2017 will be resold under a third party agreement to EnergyUnited EMC. The purchases will be resold at cost.

(h) Includes long-term service agreements and operation and maintenance agreements. Long-term service agreements include price escalation based on inflation indices.

(i) Transmission commitments are based on Southern Company's current tariff rate for point-to-point transmission.

Cautionary Statement Regarding Forward-Looking Statements

The Company's 2012 Annual Report contains forward-looking statements. Forward-looking statements include, among other things, statements concerning the strategic goals for the Company's business, customer growth, economic recovery, fuel and environmental cost recovery, current and proposed environmental regulations and related estimated expenditures, access to sources of capital, financing activities, impact of the Tax Relief Act, impact of the ATRA, estimated sales and purchases under new power sale and purchase agreements, timing of expected future capacity need in existing markets, completion of construction projects, filings with federal regulatory authorities, plans and estimated costs for new generation resources, and estimated construction and other expenditures. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "could," "should," "expects," "plans," "anticipates," "believes," "estimates," "projects," "predicts," "potential," or "continue" or the negative of these terms or other similar terminology. There are various factors that could cause actual results to differ materially from those suggested by the forward-looking statements; accordingly, there can be no assurance that such indicated results will be realized. These factors include:

- the impact of recent and future federal and state regulatory changes, including legislative and regulatory initiatives regarding deregulation and restructuring of the electric utility industry, environmental laws including regulation of water and emissions of sulfur, nitrogen, carbon, soot, particulate matter, hazardous air pollutants, including mercury, and other substances, financial reform legislation, and also changes in tax and other laws and regulations to which the Company is subject, as well as changes in application of existing laws and regulations;
- current and future litigation, regulatory investigations, proceedings, or inquiries, including Internal Revenue Service and state tax audits;
- the effects, extent, and timing of the entry of additional competition in the markets in which the Company operates;
- variations in demand for electricity, including those relating to weather, the general economy and recovery from the recent recession, population and business growth (and declines), the effects of energy conservation measures, and any potential economic impacts resulting from federal fiscal decisions;
- available sources and costs of fuels;
- effects of inflation;
- ability to control costs and avoid cost overruns during the development and construction of facilities and to construct facilities in accordance with the requirements of permits and licenses, and to satisfy any operational and environmental performance standards, including the requirements of tax credits and other incentives;
- advances in technology;
- state and federal rate regulations;
- internal restructuring or other restructuring options that may be pursued;
- potential business strategies, including acquisitions or dispositions of assets or businesses, which cannot be assured to be completed or beneficial to the Company;
- the ability of counterparties of the Company to make payments as and when due and to perform as required;
- the ability to obtain new short- and long-term contracts with wholesale customers;
- the direct or indirect effect on the Company's business resulting from terrorist incidents and the threat of terrorist incidents, including cyber intrusion;
- interest rate fluctuations and financial market conditions and the results of financing efforts, including the Company's credit ratings;
- the impacts of any potential U.S. credit rating downgrade or other sovereign financial issues, including impacts on interest rates, access to capital markets, impacts on currency exchange rates, counterparty performance, and the economy in general;
- the ability of the Company to obtain additional generating capacity at competitive prices;
- catastrophic events such as fires, earthquakes, explosions, floods, hurricanes, droughts, pandemic health events such as influenzas, or other similar occurrences;
- the direct or indirect effects on the Company's business resulting from incidents affecting the U.S. electric grid or operation of generating resources;
- the effect of accounting pronouncements issued periodically by standard setting bodies; and
- other factors discussed elsewhere herein and in other reports (including the Form 10-K) filed by the Company from time to time with the SEC.

The Company expressly disclaims any obligation to update any forward-looking statements.

CONSOLIDATED STATEMENTS OF INCOME
For the Years Ended December 31, 2012, 2011, and 2010
Southern Power Company and Subsidiary Companies 2012 Annual Report

	2012	2011	2010
		(in thousands)	
Operating Revenues:			
Wholesale revenues, non-affiliates	**$ 753,653**	$ 870,607	$ 752,772
Wholesale revenues, affiliates	**425,180**	358,585	370,630
Other revenues	**7,215**	6,769	6,939
Total operating revenues	**1,186,048**	1,235,961	1,130,341
Operating Expenses:			
Fuel	**426,257**	454,790	391,535
Purchased power, non-affiliates	**80,438**	78,368	72,657
Purchased power, affiliates	**12,915**	52,924	97,408
Other operations and maintenance	**173,074**	171,538	148,238
Loss (gain) on sale of property	**—**	—	478
Depreciation and amortization	**142,624**	124,204	119,333
Taxes other than income taxes	**19,309**	17,686	17,831
Total operating expenses	**854,617**	899,510	847,480
Operating Income	**331,431**	336,451	282,861
Other Income and (Expense):			
Interest expense, net of amounts capitalized	**(62,503)**	(77,334)	(76,120)
Loss on extinguishment of debt	**—**	(19,806)	—
Other income (expense), net	**(1,022)**	(1,223)	(76)
Total other income and (expense)	**(63,525)**	(98,363)	(76,196)
Earnings Before Income Taxes	**267,906**	238,088	206,665
Income taxes	**92,621**	75,857	75,356
Net Income	**$ 175,285**	$ 162,231	$ 131,309

The accompanying notes are an integral part of these financial statements.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
For the Years Ended December 31, 2012, 2011, and 2010
Southern Power Company and Subsidiary Companies 2012 Annual Report

	2012	2011	2010
		(in thousands)	
Net Income	**$ 175,285**	$ 162,231	$ 131,309
Other comprehensive income (loss):			
Qualifying hedges:			
Changes in fair value, net of tax of $(90), $55, and $591, respectively	**(136)**	65	938
Reclassification adjustment for amounts included in net income, net of tax of $3,919, $4,837, and $3,894, respectively	**6,189**	7,125	6,444
Total other comprehensive income (loss)	**6,053**	7,190	7,382
Comprehensive Income	**$ 181,338**	$ 169,421	$ 138,691

The accompanying notes are an integral part of these financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2012, 2011, and 2010
Southern Power Company and Subsidiary Companies 2012 Annual Report

	2012	2011	2010
		(in thousands)	
Operating Activities:			
Net income	$ 175,285	$ 162,231	$ 131,309
Adjustments to reconcile net income to net cash provided from operating activities —			
Depreciation and amortization, total	153,635	138,787	133,109
Deferred income taxes	228,780	4,481	64,530
Investment tax credits	45,047	84,723	26,400
Deferred revenues	(12,633)	(10,594)	(5,586)
Mark-to-market adjustments	(9,275)	8,000	1,492
Loss on extinguishment of debt	—	19,806	—
Other, net	3,104	495	6,078
Changes in certain current assets and liabilities —			
-Receivables	(1,384)	10,448	(23,198)
-Fossil fuel stock	(8,578)	532	2,604
-Materials and supplies	(7,825)	(4,097)	443
-Prepaid income taxes	(3,223)	10,693	4,784
-Other current assets	(1,624)	(485)	(985)
-Accounts payable	10,514	(6,138)	1,469
-Accrued taxes	431	2,134	(16,024)
-Accrued interest	385	(8,102)	53
-Other current liabilities	492	(535)	362
Net cash provided from operating activities	573,131	412,379	326,840
Investing Activities:			
Property additions	(116,633)	(254,725)	(299,602)
Cash paid for acquisitions	(124,059)	—	(105,042)
Sale of property	—	25	4,000
Change in construction payables, net	(27,387)	(14,291)	34,851
Payments pursuant to long-term service agreements	(63,932)	(57,969)	(41,598)
Other investing activities	(446)	(1,412)	(721)
Net cash used for investing activities	(332,457)	(328,372)	(408,112)
Financing Activities:			
Increase (decrease) in notes payable, net	(108,552)	(90,267)	150,840
Proceeds —			
Capital contributions	(662)	127,241	36,507
Senior notes	—	575,000	—
Other long-term debt	5,470	—	4,759
Redemptions —			
Senior notes	—	(575,000)	—
Other long-term debt	(2,450)	(3,691)	—
Premium for early debt extinguishment	—	(19,375)	—
Payment of common stock dividends	(127,000)	(91,200)	(107,100)
Other financing activities	4,169	(3,976)	3,318
Net cash provided from (used for) financing activities	(229,025)	(81,268)	88,324
Net Change in Cash and Cash Equivalents	11,649	2,739	7,052
Cash and Cash Equivalents at Beginning of Year	16,943	14,204	7,152
Cash and Cash Equivalents at End of Year	$ 28,592	$ 16,943	$ 14,204
Supplemental Cash Flow Information:			
Cash paid during the period for —			
Interest (net of $19,092, $18,001 and $12,110 capitalized, respectively)	$ 50,248	$ 74,989	$ 63,229
Income taxes (net of refunds and investment tax credits)	(175,269)	(26,486)	(6,246)
Noncash transactions — accrued property additions at year-end	11,203	32,590	46,764

The accompanying notes are an integral part of these financial statements.

CONSOLIDATED BALANCE SHEETS
At December 31, 2012 and 2011
Southern Power Company and Subsidiary Companies 2012 Annual Report

Assets	2012	2011
		(in thousands)
Current Assets:		
Cash and cash equivalents	**$ 28,592**	$ 16,943
Receivables —		
Customer accounts receivable	**62,857**	59,360
Other accounts receivable	**3,135**	2,122
Affiliated companies	**38,269**	36,508
Fossil fuel stock, at average cost	**21,616**	13,038
Materials and supplies, at average cost	**46,370**	37,603
Prepaid service agreements — current	**80,629**	28,621
Prepaid income taxes	**4,498**	5,192
Other prepaid expenses	**5,637**	4,645
Assets from risk management activities	**375**	177
Total current assets	**291,978**	204,209
Property, Plant, and Equipment:		
In service	**4,059,839**	3,167,840
Less accumulated provision for depreciation	**786,620**	652,087
Plant in service, net of depreciation	**3,273,219**	2,515,753
Construction work in progress	**24,835**	666,280
Total property, plant, and equipment	**3,298,054**	3,182,033
Other Property and Investments:		
Goodwill	**1,839**	1,839
Other intangible assets, net of amortization of $3,141 and $1,476 at December 31, 2012 and December 31, 2011, respectively	**45,979**	47,644
Total other property and investments	**47,818**	49,483
Deferred Charges and Other Assets:		
Prepaid long-term service agreements	**100,921**	115,838
Other deferred charges and assets — affiliated	**3,468**	3,029
Other deferred charges and assets — non-affiliated	**37,688**	26,385
Total deferred charges and other assets	**142,077**	145,252
Total Assets	**$ 3,779,927**	$ 3,580,977

The accompanying notes are an integral part of these financial statements.

CONSOLIDATED BALANCE SHEETS
At December 31, 2012 and 2011
Southern Power Company and Subsidiary Companies 2012 Annual Report

Liabilities and Stockholder's Equity	2012	2011
		(in thousands)
Current Liabilities:		
Securities due within one year	**$ 259**	$ 555
Notes payable — non-affiliated	**70,968**	179,520
Accounts payable —		
Affiliated	**65,832**	63,609
Other	**26,204**	44,321
Accrued taxes —		
Accrued income taxes	**87**	2,548
Other accrued taxes	**3,031**	2,158
Accrued interest	**22,259**	21,874
Liabilities from risk management activities	**669**	9,651
Other current liabilities	**8,263**	7,401
Total current liabilities	**197,572**	331,637
Long-Term Debt:		
Senior notes —		
4.875% due 2015	**525,000**	525,000
6.375% due 2036	**200,000**	200,000
5.15% due 2041	**575,000**	575,000
Other long-term notes (3.25% due 2032)	**3,828**	513
Unamortized debt premium	**2,557**	2,645
Unamortized debt discount	**(286)**	(400)
Long-term debt	**1,306,099**	1,302,758
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	**550,685**	319,790
Investment tax credits	**167,130**	125,065
Deferred capacity revenues — affiliated	**19,514**	20,637
Other deferred credits and liabilities — affiliated	**2,638**	3,618
Other deferred credits and liabilities — non-affiliated	**5,863**	4,965
Total deferred credits and other liabilities	**745,830**	474,075
Total Liabilities	**2,249,501**	2,108,470
Redeemable Noncontrolling Interest	**8,069**	3,825
Common Stockholder's Equity:		
Common stock, par value $0.01 per share —		
Authorized - 1,000,000 shares		
Outstanding - 1,000 shares	**—**	—
Paid-in capital	**1,027,548**	1,028,210
Retained earnings	**495,585**	447,301
Accumulated other comprehensive income (loss)	**(776)**	(6,829)
Total common stockholder's equity	**1,522,357**	1,468,682
Total Liabilities and Stockholder's Equity	**$ 3,779,927**	$ 3,580,977
Commitments and Contingent Matters (See notes)		

The accompanying notes are an integral part of these financial statements.

CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDER'S EQUITY
For the Years Ended December 31, 2012, 2011, and 2010
Southern Power Company and Subsidiary Companies 2012 Annual Report

	Number of Common Shares Issued	Common Stock	Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
			(in thousands)			
Balance at December 31, 2009	1	$ —	$ 864,462	$ 352,061	$ (21,401)	$1,195,122
Net income	—	—	—	131,309	—	131,309
Capital contributions from parent company	—	—	36,507	—	—	36,507
Other comprehensive income (loss)	—	—	—	—	7,382	7,382
Cash dividends on common stock	—	—	—	(107,100)	—	(107,100)
Balance at December 31, 2010	1	—	900,969	376,270	(14,019)	1,263,220
Net income	—	—	—	162,231	—	162,231
Capital contributions from parent company	—	—	127,241	—	—	127,241
Other comprehensive income (loss)	—	—	—	—	7,190	7,190
Cash dividends on common stock	—	—	—	(91,200)	—	(91,200)
Balance at December 31, 2011	**1**	**—**	**1,028,210**	**447,301**	**(6,829)**	**1,468,682**
Net income	**—**	**—**	**—**	**175,285**	**—**	**175,285**
Capital contributions from parent company	**—**	**—**	**(662)**	**—**	**—**	**(662)**
Other comprehensive income (loss)	**—**	**—**	**—**	**—**	**6,053**	**6,053**
Cash dividends on common stock	**—**	**—**	**—**	**(127,000)**	**—**	**(127,000)**
Other	**—**	**—**	**—**	**(1)**	**—**	**(1)**
Balance at December 31, 2012	**1**	**$ —**	**$1,027,548**	**$ 495,585**	**$ (776)**	**$1,522,357**

The accompanying notes are an integral part of these financial statements.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

General

Southern Power Company is a wholly-owned subsidiary of The Southern Company (Southern Company), which is also the parent company of four traditional operating companies, Southern Company Services, Inc. (SCS), Southern Communications Services, Inc. (SouthernLINC Wireless), Southern Company Holdings, Inc. (Southern Holdings), Southern Nuclear Operating Company, Inc. (Southern Nuclear), and other direct and indirect subsidiaries. The traditional operating companies – Alabama Power Company, Georgia Power Company (GPC), Gulf Power Company, and Mississippi Power Company – are vertically integrated utilities providing electric service in four Southeastern states. Southern Power Company and its subsidiaries (the Company) construct, acquire, own, and manage generation assets, including renewable energy projects, and sell electricity at market-based rates in the wholesale market. SCS, the system service company, provides, at cost, specialized services to Southern Company and its subsidiary companies. SouthernLINC Wireless provides digital wireless communications for use by Southern Company and its subsidiary companies and also markets these services to the public and provides fiber cable services within the Southeast. Southern Holdings is an intermediate holding company subsidiary, primarily for Southern Company's investments in leveraged leases. Southern Nuclear operates and provides services to the Southern Company system's nuclear power plants.

The Company is subject to regulation by the Federal Energy Regulatory Commission (FERC). The Company follows generally accepted accounting principles (GAAP). The preparation of financial statements in conformity with GAAP requires the use of estimates, and the actual results may differ from those estimates. Certain prior years' data presented in the financial statements have been reclassified to conform to the current year presentation.

The financial statements include the accounts of the Company and its wholly-owned subsidiaries, Southern Company - Florida LLC, Oleander Power Project, LP, and Nacogdoches Power LLC, which own, operate, and maintain the Company's ownership interests in Plant Stanton Unit A, Plant Oleander, and Plant Nacogdoches, respectively. The financial statements also include the accounts of the Company's wholly-owned subsidiary, Southern Renewable Energy, Inc, (SRE). SRE was formed to construct, acquire, own, and manage renewable generation assets and sell electricity at market-based prices in the wholesale market. Through Southern Turner Renewable Energy LLC (STR), a jointly-owned subsidiary owned 90% by SRE and 10% by Turner Renewable Energy, Inc. (TRE), SRE and its subsidiaries own, operate, and maintain Plant Cimarron, Plant Apex, and Plant Granville and are constructing Plant Spectrum. All intercompany accounts and transactions have been eliminated in consolidation.

Affiliate Transactions

The Company has an agreement with SCS under which the following services are rendered to the Company at amounts in compliance with FERC regulation: general and design engineering, purchasing, accounting, finance and treasury, tax, information technology, marketing, auditing, insurance and pension administration, human resources, systems and procedures, digital wireless communications, labor, and other services with respect to business and operations and transactions associated with the Southern Company system's fleet of generating units. Because the Company has no employees, all employee-related charges are rendered at amounts in compliance with FERC regulation under agreements with SCS. Costs for these services from SCS amounted to approximately $125.4 million in 2012, $112.7 million in 2011, and $105.2 million in 2010. Approximately $107.7 million in 2012, $87.9 million in 2011, and $89.6 million in 2010 were operations and maintenance expenses; the remainder was recorded to construction work in progress (CWIP), other assets, and billings in excess of cost on a construction contract. Cost allocation methodologies used by SCS prior to the repeal of the Public Utility Holding Company Act of 1935, as amended, were approved by the Securities and Exchange Commission (SEC). Subsequently, additional cost allocation methodologies have been reported to the FERC and management believes they are reasonable. The FERC permits services to be rendered at cost by system service companies.

The Company has several agreements with SCS for transmission services. Transmission purchased from affiliates totaled $6.6 million in 2012, $7.1 million in 2011, and $7.8 million in 2010. All charges were billed to the Company based on the Southern Company Open Access Transmission Tariff as filed with the FERC.

Total billings for all power purchase agreements (PPAs) with affiliates totaled $159.9 million, $175.9 million, and $230.8 million in 2012, 2011, and 2010, respectively. Included in these billings were $19.0 million, $20.6 million, and $30.5 million of "Deferred capacity revenues – affiliated" recorded on the balance sheets at December 31, 2012, 2011, and 2010, respectively. Revenue recognized under affiliate PPAs accounted for as operating leases totaled $76.2 million, $75.6 million, and $68.1 million in 2012, 2011, and 2010, respectively. The Company and the traditional operating companies may jointly enter into various types of wholesale energy, natural gas, and certain other contracts, either directly or through SCS as agent. Each participating company may be jointly and severally liable for the obligations incurred under these agreements.

The Company and the traditional operating companies generally settle amounts related to the above transactions on a monthly basis in the month following the performance of such services or the purchase or sale of electricity.

Acquisition Accounting

The Company acquires generation assets as part of its overall growth strategy. The Company accounts for business acquisitions from non-affiliates as business combinations utilizing the acquisition method in accordance with GAAP. Accordingly, the Company has included these operations in the consolidated financial statements from the respective date of acquisition. The purchase price, including contingent consideration, if any, of each acquisition was allocated based on the fair value of the identifiable assets and liabilities. Assets acquired that do not meet the definition of a business in accordance with GAAP are accounted for as asset acquisitions. The purchase price of each asset acquisition was allocated based on the relative fair value of assets acquired. Any due diligence or transition costs incurred by the Company for successful or potential acquisitions have been expensed as incurred.

Revenues

The Company sells capacity at rates specified under contractual terms for long-term PPAs. These PPAs are generally accounted for as operating leases, non-derivatives, or normal sale derivatives. Capacity revenues from PPAs classified as operating leases are recognized on a straight-line basis over the term of the agreement. Capacity revenues from PPAs classified as non-derivatives or normal sales are recognized at the lesser of the levelized amount or the amount billable under the contract over the respective contract periods. When multiple contracts exist with the same counterparty, the revenues from each contract are accounted for as separate arrangements.

The Company may also enter into contracts to sell short-term capacity in the wholesale electricity markets. These sales are generally classified as mark-to-market derivatives and net unrealized gains (losses) on such contracts are recorded in wholesale revenues. See Note 9 to the financial statements for further information.

Energy revenues and other contingent revenues are recognized in the period the energy is delivered or the service is rendered. All revenues under solar PPAs are accounted for as contingent revenues and recognized as services are performed. Transmission revenues and other fees are recognized as earned as other operating revenues. Revenues are recorded on a gross basis for all full requirements PPAs. See "Financial Instruments" herein for additional information.

Significant portions of the Company's revenues have been derived from certain customers pursuant to PPAs. For the year ended December 31, 2012, Florida Power & Light Company (FPL) accounted for 12.8% of total revenues, GPC accounted for 12.5% of total revenues, and Progress Energy Florida, Inc. accounted for 5.9% of total revenues. For the year ended December 31, 2011, FPL accounted for 14.7% of total revenues, GPC accounted for 14.0% of total revenues, and Progress Energy Carolinas, Inc. (Progress Energy Carolinas) accounted for 8.3% of total revenues. For the year ended December 31, 2010, GPC accounted for 17.7% of total revenues, FPL accounted for 11.4% of total revenues, and Progress Energy Carolinas accounted for 8.2% of total revenues.

Fuel Costs

Fuel costs are expensed as the fuel is used. Fuel costs also include emissions allowances which are expensed as the emissions occur.

Income and Other Taxes

The Company uses the liability method of accounting for deferred income taxes and provides deferred income taxes for all significant income tax temporary differences. In accordance with accounting standards related to the uncertainty in income taxes, the Company recognizes tax positions that are "more likely than not" of being sustained upon examination by the appropriate taxing authorities. See Note 5 under "Unrecognized Tax Benefits" for additional information.

Investment Tax Credits

Under the American Recovery and Reinvestment Act of 2009 (ARRA), certain construction costs related to Plant Nacogdoches, Plant Cimarron, Plant Apex, Plant Spectrum, and Plant Granville are eligible for investment tax credits (ITCs). The credits are recorded as a deferred credit, which will be amortized to income tax expense over the life of the asset, and the tax basis of the asset is reduced by 50% of the credits received, resulting in a deferred tax asset. The Company has elected to recognize the tax benefit of this basis difference as a reduction to income tax expense as costs are incurred during the construction period for construction projects two years or longer, or otherwise, when placed in service. The deferred tax asset will reverse and be recorded to income tax expense over the useful life of the asset once placed in service. The credits received during the year are shown within operating activities in the consolidated statements of cash flows.

Property, Plant, and Equipment

The Company's depreciable property, plant, and equipment consists entirely of generation assets.

Property, plant, and equipment is stated at original cost. Original cost includes: materials, direct labor incurred by contractors and affiliated companies, minor items of property, and interest capitalized. Interest is capitalized on qualifying projects during the development and construction period. The cost to replace significant items of property defined as retirement units is capitalized. The cost of maintenance, repairs, and replacement of minor items of property is charged to other operations and maintenance expense as incurred.

Depreciation

Depreciation of the original cost of assets is computed under the straight-line method and applies a composite depreciation rate based on the assets' estimated useful lives determined by the Company. The primary assets in property, plant, and equipment are power plants, which have estimated composite depreciable lives ranging from 21 to 35. These lives reflect a composite of the significant components (retirement units) that make up the plants. The Company reviews its estimated useful lives and salvage values on an ongoing basis. The results of these reviews could result in changes which could have a material impact on net income in the near term.

When property subject to composite depreciation is retired or otherwise disposed of in the normal course of business, its cost is charged to accumulated depreciation. For other property dispositions, the applicable cost and accumulated depreciation is removed from the balance sheet accounts and a gain or loss is recognized.

Impairment of Long-Lived Assets and Intangibles

The Company evaluates long-lived assets and finite-lived intangibles for impairment when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. The Company's intangible assets consist of acquired PPAs that are amortized over the term of the PPA and goodwill resulting from acquisitions. The average term of these PPAs is 20 years. The determination of whether an impairment has occurred is based on an estimate of undiscounted future cash flows attributable to the assets, as compared with the carrying value of the assets. If the estimate of undiscounted future cash flows is less than the carrying value of the asset, the fair value of the asset is determined and a loss is recorded. For assets identified as held for sale, the carrying value is compared to the estimated fair value less the cost to sell in order to determine if an impairment loss is required. Until the assets are disposed of, their estimated fair value is re-evaluated when circumstances or events change.

The amortization expense for the PPAs is as follows:

	Amortization Expense
	(in millions)
2012	$ 1.7
2013	2.5
2014	2.5
2015	2.5
2016	2.4
2017 and beyond	36.0
Total	$ 47.6

Deferred Project Development Costs

The Company capitalizes project development costs once it is determined that it is probable that a specific site will be acquired and a plant constructed. These costs include professional services, permits, and other costs directly related to the construction of a project. In addition, the Company has acquired emission reduction credits necessary for future unspecified construction in areas designated by the Environmental Protection Agency (EPA) as non-attainment areas for nitrogen oxide or volatile organic compound emissions. These credits are reflected on the balance sheets at historical cost. Deferred project development costs, including the cost of emission reduction offsets to be surrendered, are generally transferred to CWIP upon commencement of construction. The total deferred project development costs were $11.2 million at December 31, 2012, $9.9 million at December 31, 2011, and $9.6 million at December 31, 2010.

Cash and Cash Equivalents

For purposes of the financial statements, temporary cash investments are considered cash equivalents. Temporary cash investments are securities with original maturities of 90 days or less.

Materials and Supplies

Generally, materials and supplies include the average cost of generating plant materials. Materials are charged to inventory when purchased and then expensed or capitalized to plant, as appropriate, at weighted average cost when installed.

Fuel Inventory

Fuel inventory includes the cost of oil, natural gas, biomass, and emissions allowances. The Company maintains oil inventory for use at Plant Dahlberg, Plant Oleander, Plant Rowan, Plant Addison (formerly known as West Georgia), and Plant Cleveland. The Company has contracts in place for natural gas storage. These contracts help to ensure normal operations of the Company's natural gas generating units. The Company maintains biomass inventory for use at Plant Nacogdoches. Inventory is maintained using the weighted average cost method. Fuel inventory and emissions allowances are recorded at actual cost when purchased and then expensed at weighted average cost as used. Emissions allowances granted by the EPA are included at zero cost.

Financial Instruments

The Company uses derivative financial instruments to limit exposure to fluctuations in interest rates, the prices of certain fuel purchases, and electricity purchases and sales. All derivative financial instruments are recognized as either assets or liabilities (included in "Other" or shown separately as "Risk Management Activities") and are measured at fair value. See Note 8 for additional information. Substantially all of the Company's bulk energy purchases and sales contracts that meet the definition of a derivative are excluded from fair value accounting requirements because they qualify for the "normal" scope exception, and are accounted for under the accrual method. Other derivative contracts qualify as cash flow hedges of anticipated transactions. This results in the deferral of related gains and losses in accumulated other comprehensive income (AOCI) until the hedged transactions occur. Any ineffectiveness arising from cash flow hedges is recognized currently in net income. Other derivative contracts are marked to market through current period income and are recorded in the financial statement line item where they will eventually settle. See Note 9 for additional information. Cash flows from derivatives are classified on the statement of cash flows in the same category as the hedged item.

The Company does not offset fair value amounts recognized for multiple derivative instruments executed with the same counterparty under a master netting arrangement. Additionally, the Company had no outstanding collateral repayment obligations or rights to reclaim collateral arising from derivative instruments recognized at December 31, 2012.

The Company is exposed to losses related to financial instruments in the event of counterparties' nonperformance. The Company has established controls to determine and monitor the creditworthiness of counterparties in order to mitigate the Company's exposure to counterparty credit risk.

Other Income and (Expense)

Other income and (expense) includes non-operating revenues and expenses. Revenues are recognized when earned and expenses are recognized when incurred.

In December 2011, the Company redeemed its $575 million aggregate principal amount of Series B 6.25% Senior Notes due July 15, 2012. The loss recognized for the early redemption was $19.8 million primarily related to the payment of a make whole premium.

Comprehensive Income

The objective of comprehensive income is to report a measure of all changes in common stock equity of an enterprise that result from transactions and other economic events of the period other than transactions with owners. Comprehensive income consists of net income, changes in the fair value of qualifying cash flow hedges, and reclassifications of amounts included in net income.

Variable Interest Entities

The primary beneficiary of a variable interest entity (VIE) is required to consolidate the VIE when it has both the power to direct the activities of the VIE that most significantly impact the VIE's economic performance and the obligation to absorb losses or the right to receive benefits from the VIE that could potentially be significant to the VIE.

The Company has certain wholly-owned subsidiaries that are determined to be VIEs. The Company is considered the primary beneficiary of these VIEs because it controls the most significant activities of the VIEs, including operating and maintaining the respective assets, and has the obligation to absorb expected losses of these VIEs to the extent of its equity interests.

2. ACQUISITIONS AND DIVESTITURES

Granville Solar, LLC Acquisition

On October 16, 2012, the Company, through STR, acquired all of the outstanding membership interests of Granville Solar, LLC (Granville) from Sun Edison, LLC, the original developer of the project. Granville constructed and owns a 2.5 megawatt (MW) solar photovoltaic facility in Oxford, North Carolina. The solar facility began commercial operation on October 28, 2012. The output of the plant is contracted under a 20-year PPA with Progress Energy Carolinas that began in October 2012. This PPA is being accounted for as an operating lease. The acquisition is in accordance with the Company's overall growth strategy.

The Company's acquisition of Granville included cash consideration of $10.4 million. As of December 31, 2012, the allocation of the purchase price to individual assets has not been finalized. As of the acquisition date, the entire purchase price was recorded as CWIP and moved to plant in service on the balance sheets herein, once it was placed in service. Revenues and earnings with respect to Granville for the period ended December 31, 2012 were immaterial.

Spectrum Nevada Solar, LLC Acquisition

On September 28, 2012, the Company, through STR, acquired all of the outstanding membership interests of Spectrum Nevada Solar, LLC (Spectrum) from Sun Edison, LLC, the original developer of the project. Spectrum is constructing a 30-MW solar photovoltaic facility in North Las Vegas, Nevada. The solar facility is expected to begin commercial operation in mid-2013. The output of the plant is contracted under a 25-year PPA with Nevada Power Company, a subsidiary of NV Energy, Inc., that will begin in 2013. This PPA will be accounted for as an operating lease. The acquisition is in accordance with the Company's overall growth strategy.

The Company's acquisition of Spectrum consisted of cash consideration of $17.6 million paid at closing. An estimated $99.9 million will be paid to complete the construction of the solar facility. As of December 31, 2012, the allocation of the purchase price to individual assets has not been finalized. As of December 31, 2012, the $17.6 million purchase price was reflected in CWIP on the balance sheets herein.

Apex Nevada Solar, LLC Acquisition

On June 29, 2012, the Company, through STR, acquired all of the outstanding membership interests of Apex Nevada Solar, LLC (Apex) from Sun Edison, LLC, the original developer of the project. Apex constructed and owns a 20-MW solar photovoltaic facility in North Las Vegas, Nevada. The solar facility began commercial operation on July 21, 2012. The output of the plant is contracted under a 25-year PPA with Nevada Power Company, a subsidiary of NV Energy, Inc., that began in July 2012. This PPA is being accounted for as an operating lease. The acquisition is in accordance with the Company's overall growth strategy.

The Company's acquisition of Apex included consideration of $102.0 million. As of December 31, 2012, the allocation of the purchase price to individual assets has not been finalized. As of the acquisition date, the entire purchase price was recorded as CWIP and moved to plant in service on the balance sheets herein, once it was placed in service. Revenues and earnings with respect to Apex for the period ended December 31, 2012 were immaterial.

Southern Renewable Energy, Inc. Acquisition

In March 2011, Southern Company transferred ownership in its wholly-owned subsidiary, SRE, to the Company. The Company's acquisition of SRE was a transfer of net assets among entities under common control; therefore, the assets and liabilities of SRE were transferred from Southern Company to the Company at historical cost. The consolidated financial statements of the Company have been revised to include the financial condition and the results of operations of SRE since its inception in 2010. The effect of this revision was an increase of $1.3 million in net income for the year ended December 31, 2010. There was no impact on AOCI related to this change.

In 2010, the Company, through STR, entered into an engineering, construction, and procurement agreement with First Solar, Inc. for Plant Cimarron, a 30-MW solar photovoltaic plant near Cimarron, New Mexico, and assumed the associated PPA. In 2010, Plant Cimarron began commercial operation. The output from the plant is contracted under a PPA with Tri-State Generation and Transmission Association, Inc. (Tri-State). The Tri-State agreement began in December 2010 and expires in 2035. This PPA is accounted for as an operating lease.

The Company's acquisition of Cimarron included cash consideration of approximately $100 million and was allocated to property, plant, and equipment. The acquisition is in accordance with the Company's overall growth strategy. There are no contingent consideration arrangements and no significant liabilities arising from contingencies as a result of this acquisition. No goodwill or other intangible assets were recorded as a result of this acquisition.

3. CONTINGENCIES AND REGULATORY MATTERS

General Litigation Matters

The Company is subject to certain claims and legal actions arising in the ordinary course of business. In addition, the Company's business activities are subject to extensive governmental regulation related to public health and the environment. Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements such as air quality and water standards, has increased generally throughout the U.S. In particular, personal injury, property damage, and other claims for damages alleged to have been caused by carbon dioxide and other emissions and alleged exposure to hazardous materials, and/or requests for injunctive relief in connection with such matters, have become more frequent. The ultimate outcome of such pending or potential litigation against the Company and its subsidiaries cannot be predicted at this time; however, for current proceedings not specifically reported herein, management does not anticipate that the ultimate liabilities, if any, arising from such current proceedings would have a material effect on the Company's financial statements.

Climate Change Litigation

Kivalina Case

In 2008, the Native Village of Kivalina and the City of Kivalina filed a lawsuit in the U.S. District Court for the Northern District of California against several electric utilities (including Southern Company), several oil companies, and a coal company. The plaintiffs allege that the village is being destroyed by erosion allegedly caused by global warming that the plaintiffs attribute to emissions of greenhouse gases by the defendants. The plaintiffs assert claims for public and private nuisance and contend that some of the defendants (including Southern Company) acted in concert and are therefore jointly and severally liable for the plaintiffs' damages. The suit seeks damages for lost property values and for the cost of relocating the village, which is alleged to be $95 million to $400 million. In 2009, the U.S. District Court for the Northern District of California granted the defendants' motions to dismiss the case. On September 21, 2012, the U.S. Court of Appeals for the Ninth Circuit upheld the U.S. District Court for the Northern District of California's dismissal of the case. On November 27, 2012, the U.S. Court of Appeals for the Ninth Circuit denied the plaintiffs' request for review of the decision. On February 25, 2013, the plaintiffs filed a petition for writ of certiorari with the U.S. Supreme Court. Southern Company believes that these claims are without merit. While Southern Company believes the likelihood of loss is remote based on existing case law, it is not possible to predict with certainty whether the Company will incur any liability in connection with this matter. The ultimate outcome of this matter cannot be determined at this time.

Hurricane Katrina Case

In 2005, immediately following Hurricane Katrina, a lawsuit was filed in the U.S. District Court for the Southern District of Mississippi by Ned Comer on behalf of Mississippi residents seeking recovery for property damage and personal injuries caused by Hurricane Katrina. In 2006, the plaintiffs amended the complaint to include Southern Company and many other electric utilities, oil companies, chemical companies, and coal producers. The plaintiffs allege that the defendants contributed to climate change, which contributed to the intensity of Hurricane Katrina. In 2007, the U.S. District Court for the Southern District of Mississippi dismissed the case. On appeal to the U.S. Court of Appeals for the Fifth Circuit, a three-judge panel reversed the U.S. District Court for the Southern District of Mississippi, holding that the case could proceed, but, on rehearing, the full U.S. Court of Appeals for the Fifth Circuit dismissed the plaintiffs' appeal, resulting in reinstatement of the decision of the U.S. District Court for the Southern District of Mississippi in favor of the defendants. In May 2011, the plaintiffs filed an amended version of their class action complaint, arguing that the earlier dismissal was on procedural grounds and under Mississippi law the plaintiffs have a right to re-file. The amended complaint was also filed against numerous chemical, coal, oil, and utility companies, including the Company. On March 20, 2012, the U.S. District Court for the Southern District of Mississippi dismissed the plaintiffs' amended complaint. On April 16, 2012, the plaintiffs appealed the case to the U.S. Court of Appeals for the Fifth Circuit. The Company believes that these claims are without merit. While the Company believes the likelihood of loss is remote based on existing case law, it is not possible to predict with certainty whether the Company will incur any liability in connection with this matter. The ultimate outcome of this matter cannot be determined at this time.

4. JOINT OWNERSHIP AGREEMENTS

The Company is a 65% owner of Plant Stanton A, a combined-cycle project with a nameplate capacity of 659 MWs. The unit is co-owned by the Orlando Utilities Commission (28%), Florida Municipal Power Agency (3.5%), and Kissimmee Utility Authority (3.5%). The Company has a service agreement with SCS whereby SCS is responsible for the operation and maintenance of Plant Stanton A. As of December 31, 2012, $155.8 million was recorded in plant in service with associated accumulated depreciation of $36.3 million. These amounts represent the Company's share of the total plant assets and each owner is responsible for providing its own financing. The Company's proportionate share of Plant Stanton A's operating expense is included in the corresponding operating expenses in the statements of income.

5. INCOME TAXES

On behalf of the Company, Southern Company files a consolidated federal income tax return and combined state income tax returns for the States of Alabama, Georgia, Mississippi, and Texas. In addition, the Company files separate company income tax returns for the States of Florida, New Mexico, North Carolina, and South Carolina. Under a joint consolidated income tax allocation agreement, each subsidiary's current and deferred tax expense is computed on a stand-alone basis and no subsidiary is allocated more current expense than would be paid if it filed a separate income tax return. In accordance with Internal Revenue Service (IRS) regulations, each company is jointly and severally liable for the federal tax liability.

Current and Deferred Income Taxes

Details of income tax provisions are as follows:

	2012	2011	2010
		(in millions)	
Federal —			
Current	**$ (133.1)**	$ 61.6	$ 4.3
Deferred	**210.4**	12.4	46.5
	77.3	74.0	50.8
State —			
Current	**(3.0)**	9.8	6.5
Deferred	**18.3**	(7.9)	18.1
	15.3	1.9	24.6
Total	**$ 92.6**	$ 75.9	$ 75.4

The tax effects of temporary differences between the carrying amounts of assets and liabilities in the financial statements and their respective tax bases, which give rise to deferred tax assets and liabilities, are as follows:

	2012	2011
	(in millions)	
Deferred tax liabilities —		
Accelerated depreciation and other property basis differences	$ **632.9**	$ 394.8
Basis difference on asset transfers	**3.1**	3.3
Other	**6.2**	4.6
Total	**642.2**	402.7
Deferred tax assets —		
Federal effect of state deferred taxes	**25.2**	18.6
Net basis difference on investment tax credits	**28.6**	21.8
Basis difference on asset transfers	**3.9**	4.9
Alternative minimum tax carryforward	**1.1**	1.1
Unrealized loss on interest rate swaps	**15.7**	19.1
Levelized capacity revenues	**4.5**	8.2
Other	**12.7**	11.1
Total	**91.7**	84.8
Total deferred tax liabilities, net	**550.5**	317.9
Portion included in current income taxes	**0.2**	1.9
Accumulated deferred income taxes	$ **550.7**	$ 319.8

Deferred tax liabilities are the result of property related timing differences primarily due to bonus depreciation. The transfer of the Plant McIntosh construction project to GPC in 2004 resulted in a deferred gain for federal income tax purposes. GPC is reimbursing the Company for the related tax liability balance of $3.1 million. Of this total, $0.3 million is included in the balance sheets in "Receivables – Affiliated companies" and the remainder is included in "Other deferred charges and assets – affiliated."

Deferred tax assets consist primarily of timing differences related to net basis differences on ITCs, the recognition of capacity revenues, and the unrealized loss on interest rate swaps reflected in AOCI. The transfer of Plants Dahlberg, Wansley, and Franklin to the Company from GPC in 2001 also resulted in a deferred gain for federal income tax purposes. The Company will reimburse GPC for the related tax asset of $3.9 million. Of this total, $1.3 million is included in the balance sheets in "Accounts payable – Affiliated" and the remainder is included in "Other deferred credits and liabilities – affiliated."

At December 31, 2012 and December 31, 2011, the Company had a State of New Mexico net operating loss (NOL) carryforward of $117.7 million and $88.7 million, respectively. The NOL carryforward resulted in a deferred tax asset as of December 31, 2012 and December 31, 2011 of $5.4 million and $4.0 million, respectively. However, the Company has established a valuation allowance due to the remote likelihood that the full tax benefit will be realized. During 2012, the estimated amount of NOL utilization decreased resulting in a $1.0 million increase in the valuation allowance. The valuation allowance was $4.0 million as of December 31, 2012 and $3.0 million as of December 31, 2011. Of the NOL balance at December 31, 2012, $4.2 million and $1.2 million will expire in 2015 and 2017, respectively.

In 2010, the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010 (Tax Relief Act) was signed into law. Major tax incentives in the Tax Relief Act include 100% bonus depreciation for property placed in service after September 8, 2010 and through 2011 (and for certain long-term production-period projects placed in service in 2012) and 50% bonus depreciation for property placed in service in 2012 (and for certain long-term production-period projects to be placed in service in 2013). The application of the bonus depreciation provisions in the Tax Relief Act significantly increased deferred tax liabilities related to accelerated depreciation.

Effective Tax Rate

A reconciliation of the federal statutory income tax rate to the effective income tax rate is as follows:

	2012	2011	2010
Federal statutory rate	**35.0%**	35.0%	35.0%
State income tax, net of federal deduction	**3.7**	0.6	7.7
Amortization of ITC	**(1.0)**	(0.4)	—
ITC basis difference	**(2.6)**	(3.1)	(5.6)
Other	**(0.6)**	(0.3)	(0.7)
Effective income tax rate	**34.5%**	31.8%	36.4%

The Company's effective tax rate increased in 2012 primarily as a result of a decrease in the Alabama income tax deduction for federal income taxes paid.

In February 2009, President Obama signed into law the ARRA. Major tax incentives in the ARRA included renewable energy incentives. The Company received ITCs under the renewable energy incentives related to Plant Nacogdoches, Plant Cimarron, Plant Apex, and Plant Granville which had a material impact on cash flows and net income.

ITCs received in 2012 for the construction of Plant Nacogdoches, Plant Cimarron, Plant Apex, and Plant Granville were $45.0 million. The tax benefit of the basis difference reduced income tax expense by $6.9 million in 2012. See Note 1 under "Investment Tax Credits" for additional information.

ITCs received in 2011 for the construction of Plant Nacogdoches and Plant Cimarron were $84.7 million, which includes $42.9 million earned in 2010. The tax benefit of the basis difference reduced income tax expense by $7.3 million in 2011.

ITCs received in 2010 for the construction of Plant Nacogdoches were $26.4 million; the tax benefit of the basis difference reduced income tax expense by $6.9 million. The tax benefit of the basis difference related to ITCs associated with the construction of Plant Cimarron reduced tax expense by $4.6 million in 2010.

Unrecognized Tax Benefits

For 2012, the total amount of unrecognized tax benefits increased $0.3 million, resulting in a balance of $2.9 million as of December 31, 2012.

Changes during the year in unrecognized tax benefits were as follows:

	2012	2011	2010
		(in millions)	
Unrecognized tax benefits at beginning of year	**$ 2.6**	$ 2.3	$ 0.1
Tax positions from current periods	**0.7**	0.4	0.7
Tax positions from prior periods	**(0.2)**	(0.1)	1.5
Reductions due to settlements	**(0.2)**	—	—
Balance at end of year	**$ 2.9**	$ 2.6	$ 2.3

The increase in unrecognized tax benefits from current periods for 2012 relates primarily to the tax accounting method change for repairs-generation assets. See "Tax Method of Accounting for Repairs" herein for additional information. The American Jobs Creation Act of 2004 created a tax deduction for a portion of income attributable to U.S. production activities as defined in Section 199 of the Internal Revenue Code (production activities deduction). The decrease in unrecognized tax benefits from prior periods relates to the settlement of the production activities deduction.

The impact on the Company's effective tax rate, if recognized, was as follows:

	2012	2011	2010
		(in millions)	
Tax positions impacting the effective tax rate	$ **0.3**	$ 0.5	$ 0.6
Tax positions not impacting the effective tax rate	**2.6**	2.1	1.7
Balance of unrecognized tax benefits	$ **2.9**	$ 2.6	$ 2.3

The tax positions impacting the effective tax rate for 2012 primarily relate to the investment tax credits realized in 2012. The tax positions not impacting the effective tax rate for 2012 relate to the timing difference associated with the tax accounting method change for repairs-generation assets. See "Tax Method of Accounting for Repairs" herein for additional information. These amounts are presented on a gross basis without considering the related federal or state income tax impact.

Accrued interest for unrecognized tax benefits was as follows:

	2012	2011	2010
		(in millions)	
Interest accrued at beginning of year	$ **0.1**	$ —	$ —
Interest accrued during the year	**(0.1)**	0.1	—
Balance at end of year	$ —	$ 0.1	$ —

The Company classifies interest on tax uncertainties as interest expense. The Company did not accrue any penalties on uncertain tax positions.

It is reasonably possible that the amount of the unrecognized tax benefits associated with a majority of the Company's unrecognized tax positions will significantly increase or decrease within 12 months. The resolution of the tax accounting method change for repairs-generation assets, as well as the conclusion or settlement of state audits, could impact the balances significantly. At this time, an estimate of the range of reasonably possible outcomes cannot be determined.

The IRS has audited and closed all of Southern Company's consolidated federal income tax returns prior to 2009 and has settled its audits of Southern Company's consolidated federal income tax returns for 2009 and 2010, in principle, pending final approval. Additionally, the IRS has audited and closed Southern Company's 2011 consolidated federal income tax return. For tax years 2010 through 2013, Southern Company is a participant in the Compliance Assurance Process of the IRS. The audits for the Company's state income tax returns have either been concluded, or the statute of limitations has expired, for years prior to 2007.

Tax Method of Accounting for Repairs

Southern Company submitted a tax accounting method change related to the deductibility of repair costs associated with its subsidiaries' generation, transmission, and distribution systems effective for the 2009 consolidated federal income tax return in 2010. In August 2011, the IRS issued a revenue procedure, which provides a safe harbor method of accounting that taxpayers may use to determine eligible repair costs for transmission and distribution property. The IRS continues to work with the utility industry in an effort to define eligible repair costs for generation assets in a consistent manner for all utilities. The IRS published regulations on the deduction and capitalization of expenditures related to tangible property that generally apply for tax years beginning on or after January 1, 2014. The utility industry anticipates more detailed guidance concerning these regulations. Due to the uncertainty regarding the ultimate resolution of the repair costs for generation assets, an unrecognized tax position has been recorded for the tax accounting method change for repairs-generation assets. The ultimate outcome of this matter cannot be determined at this time; however, it is not expected to materially impact net income.

6. FINANCING

Other Long-Term Notes

During 2012, the Company prepaid $2.5 million on a long-term debt related to STR.

During 2012, the Company issued a $4.1 million promissory note, due June 15, 2032, to TRE related to the financing of Apex.

During 2012, the Company issued a $0.9 million promissory note, due September 30, 2032, to TRE related to the financing of Spectrum.

During 2012, the Company issued a $0.5 million promissory note, due October 31, 2032, to TRE related to the financing of Granville.

Senior Notes

During 2012, the Company did not issue any senior notes.

During 2011, the Company issued $575 million aggregate principal amount of Series 2011A 5.15% Senior Notes due September 15, 2041. The proceeds of the issuance were used to redeem $575 million aggregate principal amount of Series B 6.25% Senior Notes due July 15, 2012.

At December 31, 2012 and 2011, the Company had $1.3 billion of senior notes outstanding.

Bank Credit Arrangements

In 2011, the Company terminated its existing credit arrangement and entered into a $500 million committed credit facility (Facility) expiring in 2016. There were no borrowings outstanding under the Facility at December 31, 2012 and December 31, 2011. The Facility does not contain a material adverse change clause at the time of borrowing.

The Company is required to pay a commitment fee on the unused balance of the Facility. This fee is less than 1/4 of 1%. The Facility contains a covenant that limits the ratio of debt to capitalization (each as defined in the Facility) to a maximum of 65%. The Facility also contains a cross default provision that is restricted only to indebtedness of the Company. The Company is currently in compliance with all covenants in the Facility.

Proceeds from the Facility may be used for working capital and general corporate purposes as well as liquidity support for the Company's commercial paper program.

The Company's commercial paper program is used to finance acquisition and construction costs related to electric generating facilities and for general corporate purposes. Commercial paper is included in notes payable in the balance sheets.

Details of short-term borrowings were as follows:

	Short-term Debt at the End of the Period	
	Amount Outstanding	Weighted Average Interest Rate
	(in millions)	
December 31, 2012:		
Commercial paper	$ 71	0.5%
December 31, 2011:		
Commercial paper	$ 180	0.5%

Dividend Restrictions

The Company can only pay dividends to Southern Company out of retained earnings or paid-in-capital.

The indenture related to certain series of the Company's senior notes also contains certain limitations on the payment of common stock dividends. No dividends may be paid unless, as of the end of any calendar quarter, the Company's projected cash flows from fixed priced capacity PPAs are at least 80% of total projected cash flows for the next 12 months or the Company's debt to capitalization ratio is no greater than 60%. At December 31, 2012, the Company was in compliance with these ratios and had no other restrictions on its ability to pay dividends.

7. COMMITMENTS

Fuel Agreements

SCS, as agent for the Company and the traditional operating companies, has entered into various fuel transportation and procurement agreements to supply a portion of the fuel (primarily natural gas) requirements for the operating facilities which are not recognized on the balance sheets. In 2012, 2011, and 2010, the Company incurred fuel expense of $426.3 million, $454.8 million, and $391.5 million, respectively, the majority of which was purchased under long-term commitments. The Company expects that a substantial amount of its future fuel needs will continue to be purchased under long-term commitments.

SCS may enter into various types of wholesale energy and natural gas contracts acting as an agent for the Company and Southern Company's traditional operating companies. Under these agreements, each of the traditional operating companies and the Company may be jointly and severally liable. The credit rating of the Company is below that of the traditional operating companies; accordingly, Southern Company has entered into keep-well agreements with each of the traditional operating companies to ensure they will not subsidize or be responsible for any costs, losses, liabilities, or damages resulting from the inclusion of the Company as a contracting party under these agreements.

Operating Leases

The Company has operating lease agreements with various terms and expiration dates. Total rent expense was $0.8 million, $0.6 million, and $0.5 million for 2012, 2011, and 2010, respectively. These amounts include contingent rent expense related to the Plant Stanton Unit A land lease based on escalation in the Consumer Price Index for All Urban Consumers. The Company includes step rents, escalations, and lease concessions in its computation of minimum lease payments, which are recognized on a straight-line basis over the minimum lease term. As of December 31, 2012, estimated minimum lease payments under operating leases were $1.3 million in 2013, $1.6 million in 2014, $1.4 million in 2015, $1.3 million in 2016, $1.3 million in 2017, and $40.3 million in 2018 and thereafter. The majority of the committed future expenditures are land leases at solar facilities.

Redeemable Noncontrolling Interest

Pursuant to an agreement with TRE, on or after November 25, 2015, TRE may require the Company to purchase its noncontrolling interest in STR at fair market value.

8. FAIR VALUE MEASUREMENTS

Fair value measurements are based on inputs of observable and unobservable market data that a market participant would use in pricing the asset or liability. The use of observable inputs is maximized where available and the use of unobservable inputs is minimized for fair value measurement and reflects a three-tier fair value hierarchy that prioritizes inputs to valuation techniques used for fair value measurement.

- Level 1 consists of observable market data in an active market for identical assets or liabilities.
- Level 2 consists of observable market data, other than that included in Level 1, that is either directly or indirectly observable.
- Level 3 consists of unobservable market data. The input may reflect the assumptions of the Company of what a market participant would use in pricing an asset or liability. If there is little available market data, then the Company's own assumptions are the best available information. The need to use unobservable inputs would typically apply to long-term energy-related derivative contracts and generally results from the nature of the energy industry, as each participant forecasts its own power supply and demand and those of other participants, which directly impact the valuation of each unique contract.

In the case of multiple inputs being used in a fair value measurement, the lowest level input that is significant to the fair value measurement represents the level in the fair value hierarchy in which the fair value measurement is reported.

As of December 31, 2012, assets and liabilities measured at fair value on a recurring basis during the period, together with the level of the fair value hierarchy in which they fall, were as follows:

	Fair Value Measurements Using			
As of December 31, 2012:	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
		(in millions)		
Assets:				
Energy-related derivatives	$ —	$ 2.1	$ —	$ 2.1
Cash equivalents	26.0	—	—	26.0
Total	$ 26.0	$ 2.1	$ —	$ 28.1
Liabilities:				
Energy-related derivatives	$ —	$ 1.3	$ —	$ 1.3

As of December 31, 2011, assets and liabilities measured at fair value on a recurring basis during the period, together with the level of the fair value hierarchy in which they fall, were as follows:

	Fair Value Measurements Using			
As of December 31, 2011:	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
		(in millions)		
Assets:				
Energy-related derivatives	$ —	$ 0.6	$ —	$ 0.6
Cash equivalents	14.2	—	—	14.2
Total	$ 14.2	$ 0.6	$ —	$ 14.8
Liabilities:				
Energy-related derivatives	$ —	$ 9.8	$ —	$ 9.8

Valuation Methodologies

The energy-related derivatives primarily consist of over-the-counter financial products for natural gas and physical power products including, from time to time, basis swaps. These are standard products used within the energy industry and are valued using the market approach. The inputs used are mainly from observable market sources, such as forward natural gas prices, power prices, implied volatility, and London Interbank Offered Rate interest rates. See Note 9 for additional information on how these derivatives are used.

As of December 31, 2012 and 2011, the fair value measurements of investments calculated at net asset value per share (or its equivalent), as well as the nature and risks of those investments, were as follows:

	Fair Value	Unfunded Commitments	Redemption Frequency	Redemption Notice Period
As of December 31, 2012:		*(in millions)*		
Cash equivalents:				
Money market funds	$ 26.0	None	Daily	Not applicable
As of December 31, 2011:				
Cash equivalents:				
Money market funds	$ 14.2	None	Daily	Not applicable

The money market funds are short-term investments of excess funds in various money market mutual funds, which are portfolios of short-term debt securities. The money market funds are regulated by the SEC and typically receive the highest rating from credit rating agencies. Regulatory and rating agency requirements for money market funds include minimum credit ratings and maximum maturities for individual securities and a maximum weighted average portfolio maturity. Redemptions are available on a same day basis up to the full amount of the Company's investment in the money market funds.

As of December 31, 2012 and 2011, other financial instruments for which the carrying amount did not equal fair value were as follows:

	Carrying Amount	Fair Value
	(in millions)	
Long-term debt:		
2012	**$ 1,306**	**$ 1,444**
2011	$ 1,303	$ 1,397

The fair values are determined using Level 2 measurements and are based on quoted market prices for the same or similar issues or on the current rates offered to the Company.

9. DERIVATIVES

The Company is exposed to market risks, primarily commodity price risk and interest rate risk. To manage the volatility attributable to these exposures, the Company nets its exposures, where possible, to take advantage of natural offsets and enters into various derivative transactions for the remaining exposures pursuant to the Company's policies in areas such as counterparty exposure and risk management practices. The Company's policy is that derivatives are to be used primarily for hedging purposes and mandates strict adherence to all applicable risk management policies. Derivative positions are monitored using techniques including, but not limited to, market valuation, value at risk, stress testing, and sensitivity analysis. Derivative instruments are recognized at fair value in the balance sheets as either assets or liabilities and are presented on a gross basis.

Energy-Related Derivatives

The Company enters into energy-related derivatives to hedge exposures to electricity, gas, and other fuel price changes. The Company has limited exposure to market volatility in commodity fuel prices and prices of electricity because its long-term sales contracts shift substantially all fuel cost responsibility to the purchaser. However, the Company has been and may continue to be exposed to market volatility in energy-related commodity prices as a result of sales of uncontracted generating capacity.

To mitigate residual risks relative to movements in electricity prices, the Company enters into physical fixed-price or heat rate contracts for the purchase and sale of electricity through the wholesale electricity market. To mitigate residual risks relative to movements in gas prices, the Company may enter into fixed-price contracts for natural gas purchases; however, a significant portion of contracts are priced at market.

Energy-related derivative contracts are accounted for in one of two methods:

- *Cash Flow Hedges* – Gains and losses on energy-related derivatives designated as cash flow hedges which are used to hedge anticipated purchases and sales and are initially deferred in AOCI before being recognized in the statements of income in the same period as the hedged transactions are reflected in earnings.
- *Not Designated* – Gains and losses on energy-related derivative contracts that are not designated or fail to qualify as hedges are recognized in the statements of income as incurred.

Some energy-related derivative contracts require physical delivery as opposed to financial settlement, and this type of derivative is both common and prevalent within the electric industry. When an energy-related derivative contract is settled physically, any cumulative unrealized gain or loss is reversed and the contract price is recognized in the respective line item representing the actual price of the underlying goods being delivered.

At December 31, 2012, the net volume of energy-related derivative contracts for natural gas positions totaled 5.0 million mmBtu (million British thermal units), all of which expire by 2017, which is the longest non-hedge date. In addition to the volume discussed above, the Company enters into physical natural gas supply contracts that provide the option to sell back excess gas due to operational constraints. The maximum expected volume of natural gas subject to such a feature is immaterial.

Interest Rate Derivatives

The Company may also enter into interest rate derivatives from time to time to hedge exposure to changes in interest rates. Derivatives related to existing variable rate securities or forecasted transactions are accounted for as cash flow hedges, where the effective portion of the derivatives' fair value gains or losses is recorded in AOCI and is reclassified into earnings at the same time the hedged transactions affect earnings. The derivatives employed as hedging instruments are structured to minimize ineffectiveness, which is recorded directly to earnings.

At December 31, 2012, there were no interest rate derivatives outstanding.

The estimated pre-tax loss that will be reclassified from AOCI to interest expense for the 12-month period ending December 31, 2013 is $6.5 million. The Company has deferred gains and losses that are expected to be amortized into earnings through 2016.

Derivative Financial Statement Presentation and Amounts

At December 31, 2012 and 2011, the fair value of energy-related derivatives was reflected in the balance sheets as follows:

	Asset Derivatives			Liability Derivatives		
Derivative Category	**Balance Sheet Location**	**2012**	2011	**Balance Sheet Location**	**2012**	2011
		(in millions)			*(in millions)*	
Derivatives designated as hedging instruments in cash flow hedges						
Energy-related derivatives:	Assets from risk management activities	**$ —**	$ —	Liabilities from risk management activities	**$ —**	$ 0.8
	Other deferred charges and assets – non-affiliated	**—**	—	Other deferred credits and liabilities – non-affiliated	**—**	—
Total derivatives designated as hedging instruments in cash flow hedges		**$ —**	$ —		**$ —**	$ 0.8
Derivatives not designated as hedging instruments						
Energy-related derivatives:	Assets from risk management activities	**$ 0.4**	$ 0.2	Liabilities from risk management activities	**$ 0.7**	$ 8.8
	Other deferred charges and assets – non-affiliated	**1.7**	0.4	Other deferred credits and liabilities – non-affiliated	**0.6**	0.2
Total derivatives not designated as hedging instruments		**$ 2.1**	$ 0.6		**$ 1.3**	$ 9.0
Total		**$ 2.1**	$ 0.6		**$ 1.3**	$ 9.8

All derivative instruments are measured at fair value. See Note 8 for additional information.

For the years ended December 31, 2012, 2011, and 2010, the pre-tax effects of energy-related derivatives and interest rate derivatives designated as cash flow hedging instruments on the statements of income were as follows:

Derivatives in Cash Flow Hedging Relationships	**Gain (Loss) Recognized in AOCI on Derivative (Effective Portion)**			**Gain (Loss) Reclassified from AOCI into Income (Effective Portion)**			
					Amount		
Derivative Category	**2012**	2011	2010	**Statements of Income Location**	**2012**	2011	2010
	(in millions)				*(in millions)*		
Energy-related derivatives	**$ (0.2)**	$ 0.1	$ 1.5	Depreciation and amortization	**$ 0.4**	$ 0.4	$ 0.4
Interest rate derivatives	**—**	—	—	Interest expense, net of amounts capitalized	**(10.5)**	(11.4)	(10.8)
				Other income (expense), net	**—**	(1.0)	—
Total	**$ (0.2)**	$ 0.1	$ 1.5		**$ (10.1)**	$ (12.0)	$ (10.4)

There was no material ineffectiveness recorded in earnings for any period presented.

For the Company's energy-related derivatives not designated as hedging instruments, a substantial portion of the pre-tax realized and unrealized gains and losses is associated with hedging fuel price risk of certain PPA customers and has no impact on net income or on fuel expense as presented in the Company's statements of income. As a result, the pre-tax effects of energy-related derivatives not designated as hedging instruments on the Company's statements of income were immaterial for the years ended December 31, 2012, 2011, and 2010.

Contingent Features

The Company does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. There are certain derivatives that could require collateral, but not accelerated payment, in the event of various credit rating changes of certain affiliated companies. At December 31, 2012, the fair value of derivative liabilities with contingent features was immaterial.

At December 31, 2012, the Company had no collateral posted with its derivative counterparties; however, because of the joint and several liability features underlying these derivatives, the maximum potential collateral requirements arising from the credit-risk-related contingent features, at a rating below BBB- and/or Baa3, were $15.1 million.

Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. The Company participates in certain agreements that could require collateral in the event that one or more power pool participants has a credit rating change to below investment grade.

10. QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

Summarized quarterly financial information for 2012 and 2011 is as follows:

Quarter Ended	Operating Revenues	Operating Income	Net Income
		(in thousands)	
March 2012	**$ 253,681**	**$ 56,343**	**$ 29,316**
June 2012	**285,805**	**90,038**	**46,602**
September 2012	**354,971**	**119,234**	**68,376**
December 2012	**291,591**	**65,816**	**30,991**
March 2011	$ 281,787	$ 77,347	$ 37,743
June 2011	305,209	86,792	44,601
September 2011	362,565	108,708	56,071
December 2011	286,400	63,604	23,816

The Company's business is influenced by seasonal weather conditions.

SELECTED CONSOLIDATED FINANCIAL AND OPERATING DATA 2008-2012
Southern Power Company and Subsidiary Companies 2012 Annual Report

	2012	2011	2010	2009	2008
Operating Revenues (in thousands):					
Wholesale — non-affiliates	**$ 753,653**	$ 870,607	$ 752,772	$ 394,366	$ 667,979
Wholesale — affiliates	**425,180**	358,585	370,630	544,415	638,266
Total revenues from sales of electricity	**1,178,833**	1,229,192	1,123,402	938,781	1,306,245
Other revenues	**7,215**	6,769	6,939	7,870	7,296
Total	**$ 1,186,048**	$ 1,235,961	$ 1,130,341	$ 946,651	$ 1,313,541
Net Income (in thousands)	**$ 175,285**	$ 162,231	$ 131,309	$ 155,852	$ 144,359
Cash Dividends on Common Stock (in thousands)	**$ 127,000**	$ 91,200	$ 107,100	$ 106,100	$ 94,500
Return on Average Common Equity (percent)	**11.72**	11.88	10.68	13.36	13.03
Total Assets (in thousands)	**$ 3,779,927**	$ 3,580,977	$ 3,437,734	$ 3,043,053	$ 2,813,140
Gross Property Additions/Plant Acquisitions (in thousands)	**$ 240,692**	$ 254,725	$ 404,644	$ 331,289	$ 49,964
Capitalization (in thousands):					
Common stock equity	**$ 1,522,357**	$ 1,468,682	$ 1,263,220	$ 1,195,122	$ 1,138,361
Long-term debt	**1,306,099**	1,302,758	1,302,619	1,297,607	1,297,353
Total (excluding amounts due within one year)	**$ 2,828,456**	$ 2,771,440	$ 2,565,839	$ 2,492,729	$ 2,435,714
Capitalization Ratios (percent):					
Common stock equity	**53.8**	53.0	49.2	47.9	46.7
Long-term debt	**46.2**	47.0	50.8	52.1	53.3
Total (excluding amounts due within one year)	**100.0**	100.0	100.0	100.0	100.0
Kilowatt-Hour Sales (in thousands):					
Wholesale — non-affiliates	**15,636,986**	16,089,875	13,294,455	7,513,569	7,573,713
Wholesale — affiliates	**16,373,245**	11,773,890	10,494,339	12,293,585	9,402,020
Total	**32,010,231**	27,863,765	23,788,794	19,807,154	16,975,733
Average Revenue Per Kilowatt-Hour (cents)	**3.68**	4.41	4.72	4.74	7.69
Plant Nameplate Capacity Ratings (year-end) (megawatts)	**8,764**	7,908	7,908	7,880	7,555
Maximum Peak-Hour Demand (megawatts):					
Winter	**3,018**	3,255	3,295	3,224	3,042
Summer	**3,641**	3,589	3,543	3,308	3,538
Annual Load Factor (percent)	**48.6**	51.0	54.0	52.6	50.0
Plant Availability (percent)*	**92.9**	93.9	94.0	96.7	96.0
Source of Energy Supply (percent):					
Gas	**91.0**	89.2	88.8	84.4	75.6
Alternative (Solar and Biomass)	**0.5**	0.2	—	—	—
Purchased power —					
From non-affiliates	**7.2**	6.7	5.5	7.9	11.3
From affiliates	**1.3**	3.9	5.7	7.7	13.1
Total	**100.0**	100.0	100.0	100.0	100.0

* Beginning in 2012, plant availability is calculated as a weighted equivalent availability.

PART III

Items 10, 11, 12 (other than the information in paragraph (b) in Item 12), 13, and 14 for Southern Company are incorporated by reference to Southern Company's Definitive Proxy Statement relating to the 2013 Annual Meeting of Stockholders. Specifically, reference is made to "Nominees for Election as Directors," "Corporate Governance," and "Section 16(a) Beneficial Ownership Reporting Compliance" for Item 10, "Executive Compensation," "Compensation Discussion and Analysis," "Compensation and Management Succession Committee Report," "Director Compensation," and "Director Compensation Table" for Item 11, "Stock Ownership Table" for Item 12, "Certain Relationships and Related Transactions" and "Director Independence" for Item 13, and "Principal Public Accounting Firm Fees" for Item 14.

Items 10, 11, 12 (other than the information in paragraph (b) in Item 12), 13, and 14 for Alabama Power, Georgia Power, and Mississippi Power are incorporated by reference to the Definitive Information Statements of Alabama Power, Georgia Power, and Mississippi Power relating to each of their respective 2013 Annual Meetings of Shareholders. Specifically, reference is made to "Nominees for Election as Directors," "Corporate Governance," and "Section 16(a) Beneficial Ownership Reporting Compliance" for Item 10, "Executive Compensation," "Compensation Discussion and Analysis," "Compensation and Management Succession Committee Report," "Director Compensation," and "Director Compensation Table" for Item 11, "Stock Ownership Table" for Item 12, "Certain Relationships and Related Transactions" and "Director Independence" for Item 13, and "Principal Public Accounting Firm Fees" for Item 14.

Items 10, 11, 12, 13, and 14 for Gulf Power are contained herein.

Items 10, 11, 12 and 13 for Southern Power are omitted pursuant to General Instruction I(2)(c) of Form 10-K. Item 14 for Southern Power is contained herein.

Item 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Identification of directors of Gulf Power.

S. W. Connally, Jr. President and Chief Executive Officer Age 43 Served as Director since 2012	**William C. Cramer, Jr.** *(1)* Age 60 Served as Director since 2002
Allan G. Bense *(1)* Age 61 Served as Director since 2010	**J. Mort O'Sullivan, III** *(1)* Age 61 Served as Director since 2010
Deborah H. Calder *(1)* Age 52 Served as Director since 2010	**Winston E. Scott** *(1)* Age 62 Served as Director since 2003

(1) No position other than director.

Each of the above is currently a director of Gulf Power, serving a term running from the last annual meeting of Gulf Power's shareholders (June 26, 2012) for one year until the next annual meeting or until a successor is elected and qualified, except for Mr. Connally whose election was effective July 1, 2012.

There are no arrangements or understandings between any of the individuals listed above and any other person pursuant to which he or she was or is to be selected as a director, other than any arrangements or understandings with directors or officers of Gulf Power acting solely in their capacities as such.

Identification of executive officers of Gulf Power.

S. W. Connally, Jr. President and Chief Executive Officer Age 43 Served as Executive Officer since 2012	**Michael L. Burroughs** Vice President — Senior Production Officer Age 52 Served as Executive Officer since 2010
P. Bernard Jacob Vice President — Customer Operations Age 58 Served as Executive Officer since 2003	**Bentina C. Terry** Vice President — External Affairs and Corporate Services Age 42 Served as Executive Officer since 2007
Richard S. Teel Vice President and Chief Financial Officer Age 42 Served as Executive Officer since 2010	

Each of the above is currently an executive officer of Gulf Power, serving a term until the next annual organizational meeting or until a successor is elected and qualified.

There are no arrangements or understandings between any of the individuals listed above and any other person pursuant to which he or she was or is to be selected as an officer, other than any arrangements or understandings with directors or officers of Gulf Power acting solely in their capacities as such.

Identification of certain significant employees. *None.*

Family relationships. *None.*

Business experience. *Unless noted otherwise, each director has served in his or her present position for at least the past five years.*

DIRECTORS

Gulf Power's Board of Directors possesses collective knowledge and experience in accounting, finance, leadership, business operations, risk management, corporate governance, and Gulf Power's industry.

S. W. Connally, Jr. - President and Chief Executive Officer of Gulf Power since July 1, 2012. Mr. Connally previously served as Senior Vice President and Chief Production Officer of Georgia Power from July 2010 through June 2012 and Manager of Alabama Power's Plant Barry from August 2007 through July 2010.

Allan G. Bense - Panama City businessman and former Speaker of the Florida House of Representatives. Mr. Bense is a partner in several companies involved in road building, mechanical contracting, insurance, general contracting, golf courses, and farming and represented the Bay County area in the Florida House of Representatives beginning in 1998 and served as Speaker of the House from 2004 through 2006. Mr. Bense has also served as Vice Chair of Enterprise Florida, the economic development agency for the state, from January 2009 to January 2011.

Deborah H. Calder - Senior Vice President for Navy Federal Credit Union since June 2008. Since September 2007, Ms. Calder has directed the day-to-day operations of more than 2,700 employees and the ongoing construction of Navy Federal Credit Union's campus in the Pensacola area. Ms. Calder has been with Navy Federal Credit Union for over 20 years, serving in previous positions as Vice President of Consumer and Credit Card Lending, Vice President of Collections, Vice President of Call Center Operations, and Assistant Vice President of Credit Cards.

William C. Cramer, Jr. - President and Owner of automobile dealerships in Florida, Georgia, and Alabama. Mr. Cramer has been an authorized Chevrolet dealer since 1986. In 2009, Mr. Cramer became an authorized dealer of Cadillac, Buick, and GMC vehicles.

J. Mort O'Sullivan, III - Managing Partner of Warren Averett O'Sullivan Creel LLP, an accounting firm originally formed as O'Sullivan Patton Jacobi in 1981. Mr. O'Sullivan currently focuses on consulting and management advisory services to clients, while continuing to offer his expertise in litigation support, business valuations, and mergers and acquisitions. He is a registered investment advisor.

Winston E. Scott - Senior Vice President for External Relations, Florida Institute of Technology since March 2012. He previously served as Dean, College of Aeronautics, Florida Institute of Technology, Melbourne, Florida from August 2008 through March 2012 and Vice President and Deputy General Manager, Engineering and Science Contract Group at Jacobs Engineering, Houston, Texas, from September 2006 through July 2008. Mr. Scott is also a member of the board of directors of Environmental Tectonics Corporation. Mr. Scott's experience also included serving as a pilot in the U.S. Navy, as an astronaut with the National Aeronautic and Space Administration, and as executive director of the Florida Space Authority.

EXECUTIVE OFFICERS

Michael L. Burroughs - Vice President and Senior Production Officer since August 2010. He previously served as Manager of Georgia Power's Plant Yates from September 2007 to July 2010.

P. Bernard Jacob - Vice President of Customer Operations since 2007.

Richard S. Teel - Vice President and Chief Financial Officer since August 2010. He previously served as Vice President and Chief Financial Officer of Southern Company Generation, a business unit of Southern Company, from January 2007 to July 2010.

Bentina C. Terry - Vice President of External Affairs and Corporate Services since 2007.

Involvement in certain legal proceedings. None.

Promoters and Certain Control Persons. None.

Section 16(a) Beneficial Ownership Reporting Compliance. None.

Code of Ethics

The registrants collectively have adopted a code of business conduct and ethics (Code of Ethics) that applies to each director, officer, and employee of the registrants and their subsidiaries. The Code of Ethics can be found on Southern Company's website located at www.southerncompany.com. The Code of Ethics is also available free of charge in print to any shareholder by requesting a copy from Melissa K. Caen, Assistant Secretary, Southern Company, 30 Ivan Allen Jr. Boulevard NW, Atlanta, Georgia 30308. Any amendment to or waiver from the code of ethics that applies to executive officers and directors will be posted on the website.

Corporate Governance

Southern Company has adopted corporate governance guidelines and committee charters. The corporate governance guidelines and the charters of Southern Company's Audit Committee, Compensation and Management Succession Committee, Finance Committee, Governance Committee, and Nuclear/Operations Committee can be found on Southern Company's website located at www.southerncompany.com. The corporate governance guidelines and charters are also available free of charge in print to any shareholder by requesting a copy from Melissa K. Caen, Assistant Secretary, Southern Company, 30 Ivan Allen Jr. Boulevard NW, Atlanta, Georgia 30308.

Item 11. EXECUTIVE COMPENSATION

GULF POWER

COMPENSATION DISCUSSION AND ANALYSIS (CD&A)

In this CD&A and this Form 10-K, references to the "Compensation Committee" are to the Compensation and Management Succession Committee of the Board of Directors of Southern Company.

This section describes the compensation program for Gulf Power's Chief Executive Officer and Chief Financial Officer in 2012, as well as each of its other three most highly compensated executive officers serving at the end of the year.

S. W. Connally, Jr.	President and Chief Executive Officer
Richard S. Teel	Vice President and Chief Financial Officer
Michael L. Burroughs	Vice President
P. Bernard Jacob	Vice President
Bentina C. Terry	Vice President

Additionally, described is the compensation of Gulf Power's former President and Chief Executive Officer, Mark A. Crosswhite, who is now Executive Vice President and Chief Operating Officer of Southern Company. Collectively, these officers are referred to as the named executive officers.

Executive Summary

Performance

Performance-based pay represents a substantial portion of the total direct compensation paid or granted to the named executive officers for 2012.

	Salary ($)(1)	% of Total	Short-Term Performance Pay ($)(1)	% of Total	Long-Term Performance Pay ($)(1)	% of Total
S. W. Connally, Jr.	295,103	45	226,783	34	136,049	21
R. S. Teel	236,882	48	115,118	23	143,417	29
M. L. Burroughs	187,855	53	91,572	26	75,660	21
P. B. Jacob	253,959	48	120,432	23	152,917	29
B. C. Terry	255,634	48	123,535	23	153,909	29

(1) Salary is the actual amount paid in 2012, Short-Term Performance Pay is the actual amount earned in 2012 based on performance, and Long-Term Performance Pay is the value on the grant date of stock options and performance shares granted in 2012. See the Summary Compensation Table for the amounts of all elements of reportable compensation described in this CD&A.

Gulf Power financial and operational and Southern Company earnings per share (EPS) goal results for 2012 are shown below:

Financial: 46% of Target Operational: 148% of Target EPS: 128% of Target

Southern Company's total shareholder return has been:

1-Year: -3.4% 3-Year: 13.9% 5-year: 7.1%

These levels of achievement resulted in payouts that were aligned with Gulf Power and Southern Company performance.

Compensation and Benefit Beliefs

The compensation and benefit program is based on the following beliefs:

- Employees' commitment and performance have a significant impact on achieving business results;
- Compensation and benefits offered must attract, retain, and engage employees and must be financially sustainable;
- Compensation should be consistent with performance: higher pay for higher performance and lower pay for lower performance; and
- Both business drivers and culture should influence the compensation and benefit program.

Based on these beliefs, the Compensation Committee believes that Gulf Power's executive compensation program should:

- Be competitive with the companies in Gulf Power's industry;
- Motivate and reward achievement of Gulf Power's goals;
- Be aligned with the interests of Southern Company's stockholders and Gulf Power's customers; and
- Not encourage excessive risk-taking.

Executive compensation is targeted at the market median of industry peers, but actual compensation is primarily determined by achievement of Gulf Power's business goals. Gulf Power believes that focusing on its customers drives achievement of financial objectives and delivery of a premium, risk-adjusted total shareholder return for Southern Company's stockholders. Therefore, short-term performance pay is based on achievement of Gulf Power's operational and financial performance goals, with one-third determined by operational performance, such as safety, reliability, and customer satisfaction; one-third determined by financial performance; and one-third determined by Southern Company's EPS performance. Long-term performance pay is tied to Southern Company's stockholder value with 40% of the target value awarded in Southern Company stock options, which reward stock price appreciation, and 60% awarded in performance share units, which reward Southern Company's total shareholder return performance relative to that of industry peers and stock price appreciation.

Key Governance and Pay Practices

- Annual pay risk assessment required by the Compensation Committee charter.
- Retention of an independent compensation consultant by the Compensation Committee, Pay Governance LLC, that provides no other services to Gulf Power or Southern Company.
- Inclusion of a claw-back provision that permits the Compensation Committee to recoup performance pay from any employee if determined to have been based on erroneous results, and requires recoupment from an executive officer in the event of a material financial restatement due to fraud or misconduct of the executive officer.
- No excise tax gross-up on change-in-control severance arrangements.
- Provision of limited perquisites and no income tax gross-ups for the Chief Executive Officer except on certain relocation-related benefits.
- "No-hedging" provision in Gulf Power's inside trading policy that is applicable to all employees.
- Strong stock ownership requirements that are being met by all named executive officers.

ESTABLISHING EXECUTIVE COMPENSATION

The Compensation Committee establishes the Southern Company system executive compensation program. In doing so, the Compensation Committee uses information from others, principally its independent compensation consultant, Pay Governance LLC. The Compensation Committee also relies on information from Southern Company's Human Resources staff and, for individual executive officer performance, from Southern Company's and Gulf Power's respective Chief Executive Officers. The role and information provided by each of these sources is described throughout this CD&A.

Consideration of Advisory Vote on Executive Compensation

The Compensation Committee considered the stockholder vote on Southern Company's executive compensation at the 2012 Annual Meeting of Stockholders. In light of the significant support of Southern Company's stockholders (95% of votes cast voting in favor of the proposal) and the actual payout levels of the performance-based compensation program, the Compensation Committee continues to believe that the executive compensation program is competitive and is aligned with financial and operational performance and is in the best interests of Gulf Power's customers and Southern Company's stockholders.

Executive Compensation Focus

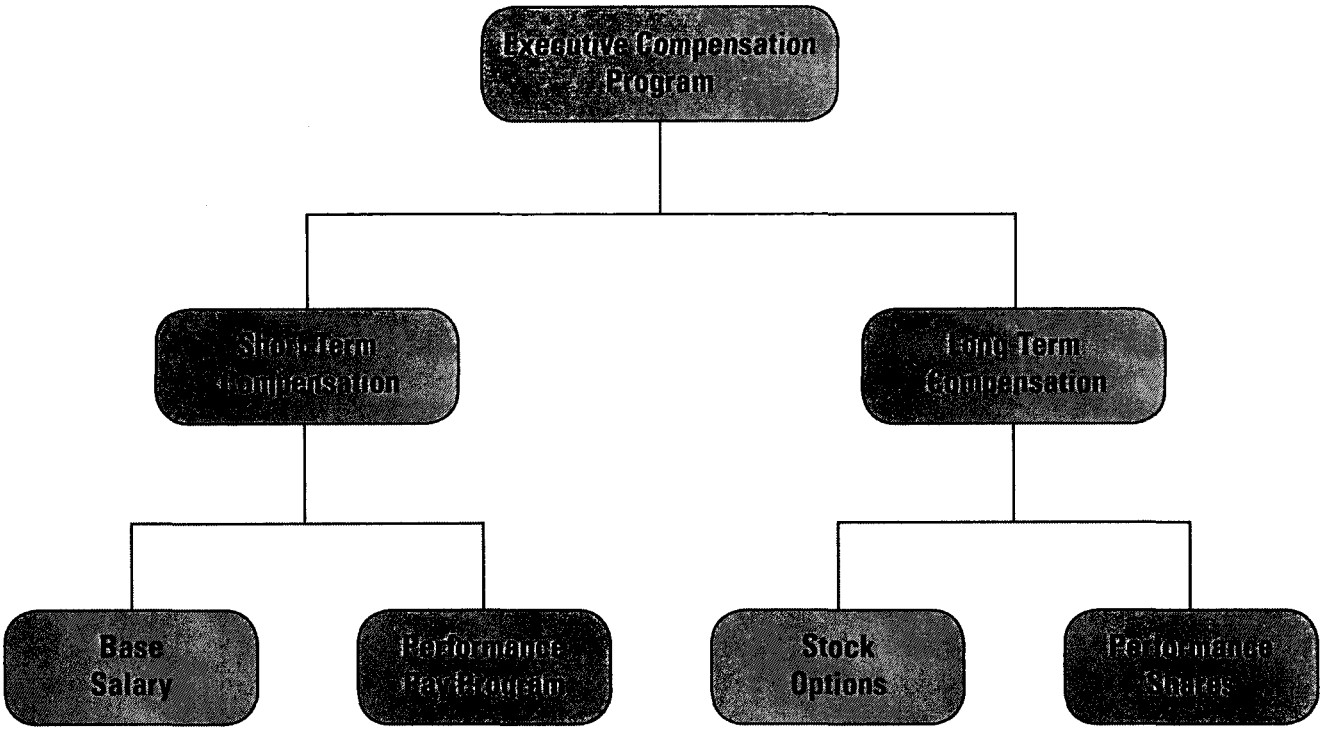
The executive compensation program places significant focus on rewarding performance. The program is performance-based in several respects:

- Business unit performance, which includes return on equity (ROE) or net income, and operational performance, compared to target performance levels established early in the year, and EPS determine the actual payouts under the short-term (annual) performance-based compensation program (Performance Pay Program).
- Southern Company Common Stock (Common Stock) price changes result in higher or lower ultimate values of stock options.
- Southern Company total shareholder return compared to those of industry peers leads to higher or lower payouts under the Performance Share Program (performance shares).

In support of this performance-based pay philosophy, Gulf Power has no general employment contracts or guaranteed severance with the named executive officers, except upon a change in control. The pay-for-performance principles do not only apply to the named executive officers. The Performance Pay Program covers almost all of the 1,400 employees of Gulf Power. Stock options and performance shares are granted to nearly 125 employees of Gulf Power. These programs engage employees, which ultimately is good not only for them, but also for Gulf Power's customers and Southern Company's stockholders.

OVERVIEW OF EXECUTIVE COMPENSATION COMPONENTS

The primary components of the 2012 executive compensation program are shown below:



Gulf Power's executive compensation program consists of a combination of short-term and long-term components. Short-term compensation includes base salary and the Performance Pay Program. Long-term compensation includes stock options and performance shares. The performance-based compensation components are linked to financial and operational performance, stock performance, and Southern Company's total shareholder return. The executive compensation program is approved by the Compensation Committee, which consists entirely of independent directors. The Compensation Committee believes that the executive compensation program is a balanced program that provides market-based compensation and motivates and rewards performance.

ESTABLISHING MARKET-BASED COMPENSATION LEVELS

For the named executive officers, the Compensation Committee and Southern Company Human Resources staff review compensation data from large, publicly-owned electric and gas utilities. The data was developed and analyzed by Pay Governance LLC, the independent compensation consultant retained by the Compensation Committee. The companies included each year in the primary peer group are those whose data is available through the consultant's database. Those companies are drawn from this list of primarily regulated utilities of $2 billion in revenues and up.

Alliant Energy Corporation	First Solar Inc.	Pinnacle West Capital Corporation
Ameren Corporation	GenOn Energy, Inc.	PPL Corporation
American Electric Power Company, Inc.	GDF SUEZ Energy North America, Inc.	Progress Energy, Inc.
Atmos Energy Corporation	Iberdrola, S.A.	Public Service Enterprise Group Inc.
Bg US Services, Inc.	Integrys Energy Group, Inc.	Puget Energy, Inc.
Calpine Corporation	Invensys plc	Salt River Project
CenterPoint Energy, Inc.	Kinder Morgan Energy Partners, L.P.	SCANA Corporation
CMS Energy Corporation	LG&E and KU Energy LLC	Sempra Energy
Consolidated Edison, Inc.	McDermott International, Inc.	Southern Union Company
Constellation Energy Group, Inc.	MDU Resources Group, Inc.	Spectra Energy Corp.
CPS Energy	MidAmerican Energy Company	Targa Resources Partners LP
Crosstex Energy, Inc.	National Grid USA	TECO Energy, Inc.
Dominion Resources, Inc.	New York Power Authority	Tennessee Valley Authority
DTE Energy Company	NextEra Energy, Inc.	The AES Corporation
Duke Energy Corporation	Nicor Inc.	The Babcock & Wilcox Company
Edison International	Northeast Utilities	The Williams Companies, Inc.
El Paso Corporation	NRG Energy, Inc.	TransCanada Corporation
Enbridge Energy Partners, LP	NSTAR	UGI Corporation
Energy Future Holdings Corp.	NV Energy, Inc.	Vectren Corporation
Entergy Corporation	OGE Energy Corp.	Westar Energy, Inc.
Enterprise Products Partners L.P.	Oncor Electric Delivery Company LLC	Wisconsin Energy Corporation
Exelon Corporation	Pepco Holdings, Inc.	Xcel Energy Inc.
FirstEnergy Corp.		

Market data for the chief executive officer position and other positions in terms of scope of responsibilities that most closely resemble the positions held by the named executive officers is reviewed. When appropriate, the market data is size-adjusted, up or down, to accurately reflect comparable scopes of responsibility. Based on the data, a total target compensation opportunity is established for each named executive officer. Total target compensation opportunity is the sum of base salary, annual performance-based compensation at a target performance level, and long-term performance-based compensation (stock options and performance shares) at a target value. Actual compensation paid may be more or less than the total target compensation opportunity based on actual performance above or below target performance levels. As a result, the compensation program is designed to result in payouts that are market-appropriate given Gulf Power's and Southern Company's performance for the year or period. A specified weight was not targeted for base salary or annual or long-term performance-based compensation as a percentage of total target compensation opportunities, nor did amounts realized or realizable from prior compensation serve to increase or decrease 2012 compensation amounts. Total target compensation opportunities for senior management as a group, including the named executive officers, are managed to be at the median of the market for companies of similar size in the electric utility industry. Therefore, some executives may be paid above and others below market. This practice allows for differentiation based on time in the position, scope of responsibilities, and individual performance. The differences in the total pay opportunities for each named executive officer are based almost exclusively on the differences indicated by the market data for persons holding similar positions. Because of the use of market data from a large number of industry peer companies for positions that are not identical in terms of scope of responsibility from company to company, minor differences are not considered to be material and the compensation program is believed to be market-appropriate, as long as senior management as a group is within an appropriate range. Generally, compensation is considered to be within an appropriate range if it is not more or less than 15% of the applicable market data. The total target compensation opportunity was established in early 2012 for each named executive officer below:

	Salary ($)	Target Annual Performance-Based Compensation ($)	Target Long-Term Performance-Based Compensation ($)	Total Target Compensation Opportunity ($)
S. W. Connally, Jr.	226,752	102,038	136,049	464,839
M. A. Crosswhite	411,529	246,917	534,966	1,193,412
R. S. Teel	239,082	107,587	143,417	490,086
M. L. Burroughs	189,199	75,680	75,660	340,539
P. B. Jacob	254,882	114,697	152,917	522,496
B. C. Terry	256,563	115,453	153,909	525,925

The salary levels shown above were not effective until March 2012. Therefore, the salary amounts reported in the Summary Compensation Table are different than the amounts shown above because that table reports actual amounts paid in 2012. Until July 1, 2012, Mr. Connally served as Senior Vice President of Southern Company Generation and Georgia Power and Mr. Crosswhite served as Chief Executive Officer of Gulf Power. Both Messrs. Connally and Crosswhite received promotions at that time resulting in increases in salary to $361,250 and $488,750, respectively, and increases in target annual performance-based compensation to $216,750 and $342,125, respectively.

For purposes of comparing the value of the compensation program to the market data, stock options are valued at $3.39 per option and performance shares at $41.99 per unit. These values represent risk-adjusted present values on the date of grant and are consistent with the methodologies used to develop the market data. The mix of stock options and performance shares granted were 40% and 60%, respectively, of the long-term value shown above.

In 2011, Pay Governance LLC analyzed the level of actual payouts for 2010 performance under the annual Performance Pay Program to the named executive officers relative to performance versus peer companies to provide a check on the goal-setting process, including goal levels and associated performance-based pay opportunities. The findings from the analysis were used in establishing performance goals and the associated range of payouts for goal achievement for 2012. That analysis was updated in 2012 by Pay Governance LLC for 2011 performance, and those findings were used in establishing goals for 2013.

DESCRIPTION OF KEY COMPENSATION COMPONENTS

2012 Base Salary

Most employees, including all of the named executive officers, received base salary increases in 2012.

With the exception of Southern Company executive officers, base salaries for all Southern Company system officers are within a position level with a base salary range that is established by Southern Company Human Resources staff using the market data described above. Each officer is within one of these established position levels based on the scope of responsibilities that most closely resemble the positions included in the market data described above. The base salary level for individual officers is set within the applicable pre-established range. Factors that influence the specific base salary level within the range include the need to retain an experienced team, internal equity, time in position, and individual performance. Individual performance includes the degree of competence and initiative exhibited and the individual's relative contribution to the results of operations in prior years. Base salaries are reviewed annually in February and changes are made effective March 1. The base salary levels established early in the year for the named executive officers were set within the applicable position level salary range and were recommended by the individual named executive officer's superior and approved by Southern Company's Chief Executive Officer. Mr. Crosswhite's and Mr. Connally's base salaries that were increased effective July 1, 2012 were approved by the Compensation Committee.

2012 Performance-Based Compensation

This section describes performance-based compensation for 2012.

Achieving Operational and Financial Performance Goals — The Guiding Principle for Performance-Based Compensation

The Southern Company system's number one priority is to continue to provide customers outstanding reliability and superior service at reasonable prices while achieving a level of financial performance that benefits Southern Company's stockholders in the short and long term. Operational excellence and business unit and Southern Company financial performance are integral to the achievement of business results that benefit customers and stockholders.

Therefore, in 2012, Gulf Power strove for and rewarded:

- Continuing industry-leading reliability and customer satisfaction, while maintaining reasonable retail prices; and
- Meeting energy demand with the best economic and environmental choices.

In 2012, Gulf Power also focused on and rewarded:

- EPS growth;
- ROE – target performance level in the top quartile of comparable electric utilities;
- Southern Company dividend growth;
- Long-term, risk-adjusted total shareholder return; and
- Financial integrity — an attractive risk-adjusted return, sound financial policy, and a stable "A" credit rating.

The performance-based compensation program is designed to encourage achievement of these goals. The Southern Company Chief Executive Officer, with the assistance of Southern Company's Human Resources staff, recommended to the Compensation Committee the program design and award amounts for senior management, including the named executive officers.

2012 Annual Performance-Based Pay Program

Annual Performance Pay Program Highlights

- Rewards achievement of annual goals:
  - EPS
  - Business unit financial performance (ROE or net income)
  - Business unit operational performance
- Goals are weighted one-third each
- Performance results range from 0% to 200% of target, based on level of goal achievement

Overview of Program Design

Almost all employees of Gulf Power, including the named executive officers, are participants.

The performance goals are set at the beginning of each year by the Compensation Committee.

- For Southern Company's traditional operating companies, including Gulf Power, operational goals are safety, customer satisfaction, plant availability, transmission and distribution system reliability, and culture. For the nuclear operating company, Southern Nuclear, operational goals are safety, plant operations, and culture. Each of these operational goals is explained in more detail under Goal Details below. The level of achievement for each operational goal is determined according to the respective performance schedule, and the total operational goal performance is determined by the weighted average result. Each business unit has its own operational goals.

- EPS is defined as Southern Company's earnings from continuing operations divided by average shares outstanding during the year. The EPS performance measure is applicable to all participants in the Performance Pay Program.

- For Southern Company's traditional operating companies, including Gulf Power, the business unit financial performance goal is ROE, which is defined as the traditional operating company's net income divided by average equity for the year. For Southern Power, the business unit financial performance goal is net income, excluding net income from acquisitions.

The Compensation Committee may make adjustments, both positive and negative, to goal achievement for purposes of determining payouts. For the financial performance goals, such adjustments could include the impact of items considered non-recurring or outside of normal operations or not anticipated in the business plan when the EPS goal was established and of sufficient magnitude to warrant recognition. The EPS goal results were decreased two cents per share to exclude the impact of an insurance recovery related to the MC Asset Recovery, LLC (MCAR) litigation settlement. This reduction decreased average payouts approximately 7%. The Compensation Committee believed this adjustment was necessary because EPS goal results were increased in 2009 by the amount of the MCAR litigation settlement. For Messrs. Connally, Crosswhite, and Jacob, the safety goal achievement level was reduced by 20% for purposes of calculating their respective payouts under the Performance Pay Program because there was a work-related fatality in 2012 at Gulf Power. The reduction was approved by the Compensation Committee. This reduction is reflected in the total performance factor reported on page III-14 of this CD&A. Additionally, under the terms of the program, no payout can be made if Southern Company's current earnings are not sufficient to fund the Common Stock dividend at the same level or higher than the prior year.

Goal Details

Operational Goals	Description	Why It Is Important
Customer Satisfaction	Customer satisfaction surveys evaluate performance. The survey results provide an overall ranking for each traditional operating company, including Gulf Power, as well as a ranking for each customer segment: residential, commercial, and industrial.	Customer satisfaction is key to operations. Performance of all operational goals affect customer satisfaction.
Reliability	Transmission and distribution system reliability performance is measured by the frequency and duration of outages. Performance targets for reliability are set internally based on recent historical performance.	Reliably delivering power to customers is essential to Gulf Power's operations.
Availability	Peak season equivalent forced outage rate is an indicator of availability and efficient generation fleet operations during the months when generation needs are greatest. Availability is measured as a percentage of the hours of forced outages out of the total generation hours.	Availability of sufficient power during peak season fulfills the obligation to serve and provide customers with the least cost generating resources.
Nuclear Plant Operations	Nuclear plant performance is evaluated by measuring nuclear safety as rated by independent industry evaluators, as well as by a quantitative score comprised of various plant performance indicators. Plant reliability and operational availability is measured as a percentage of time the nuclear plant is operating, and accommodates generation reductions associated with planned outages. In addition, a subjective assessment of progress on the construction and licensing of Georgia Power's two new nuclear units, Plant Vogtle Units 3 and 4, is also in place.	Safe and efficient operation of the nuclear fleet is important for delivering clean energy at a reasonable price.
Safety	Southern Company's Target Zero program is focused on continuous improvement in having a safe work environment. The performance is measured by the applicable company's ranking, as compared to peer utilities in the Southeastern Electric Exchange.	Essential for the protection of employees, customers, and communities.
Culture	The culture goal seeks to improve Gulf Power's inclusive workplace. This goal includes measures for work environment (employee satisfaction survey), representation of minorities and females in leadership roles (subjectively assessed), and supplier diversity.	Supports workforce development efforts and helps to assure diversity of suppliers.

Financial Performance Goals	Description	Why It Is Important
EPS	Southern Company's earnings from continuing operations divided by average shares outstanding during the year.	Supports commitment to provide Southern Company's stockholders solid risk-adjusted returns.
Business Unit ROE/ Net Income	For the traditional operating companies, including Gulf Power, the business unit financial performance goal is ROE, which is defined as the applicable company's net income divided by average equity for the year. For Southern Power, the business unit financial performance goal is net income, excluding income from acquisitions.	Supports delivery of Southern Company stockholder value and contributes to Gulf Power's and Southern Company's sound financial policies and stable credit ratings.

The ranges of performance levels established for the primary operational goals are detailed below.

Level of Performance	Customer Satisfaction	Reliability	Availability	Nuclear Plant Operations	Safety	Culture
Maximum	Top quartile for all customer segments and overall	Significantly exceed target	Industry best	Significantly exceed targets	Greater than top 20th percentile and company best	Significant improvement
Target	Top quartile overall	Meet target	Top quartile	Meet targets	Top 40th percentile	Improvement
Threshold	2nd quartile overall	Significantly below target	2nd quartile	Significantly below targets	Top 60th percentile	Significantly below expectations

The Compensation Committee approves specific objective performance schedules to calculate performance between the threshold, target, and maximum levels for each of the operational goals. If goal achievement is below threshold, there is no payout associated with the applicable goal.

EPS and Business Unit Financial Performance:

The range of EPS, business unit ROE, and Southern Power net income goals for 2012 is shown below. ROE goals vary from the allowed retail ROE range due to state regulatory accounting requirements, wholesale activities, other non-jurisdictional revenues and expenses, and other activities not subject to state regulation.

Level of Performance	EPS ($)	ROE (%)	Southern Power Net Income ($) (millions) (1)
Maximum	2.77	14.0	195
Target	2.64	12.0	155
Threshold	2.51	10.0	115

(1) Excluding income from acquisitions.

For 2012, the Compensation Committee established a minimum EPS performance threshold that must be achieved. If EPS was less than $2.38 (90% of Target), not only would there have been no payout associated with EPS performance, but overall payouts under the Performance Pay Program would have been reduced by 10% of target. In setting the goals for pay purposes, the Compensation Committee relies on information on financial and operational goals from the Finance Committee and the Nuclear/Operations Committee of Southern Company's Board of Directors, respectively.

2012 Achievement

Each named executive officer had a target Performance Pay Program opportunity, based on his or her position, set by the Compensation Committee at the beginning of 2012. Targets are set as a percentage of base salary. Mr. Connally's target was initially set at 45% and increased to 60% effective July 1, 2012. Mr. Crosswhite's was initially set at 60% and increased to 70% effective July 1, 2012. For Ms. Terry and Messrs. Jacobs and Teel, the targets were set at 45% each and, for Mr. Burroughs, it was set at 40%. Actual payouts were determined by adding the payouts derived from EPS and applicable business unit operational and financial performance goal achievement for 2012 and dividing by three. EPS exceeded the minimum threshold established and therefore payouts were not affected. Actual 2012 goal achievement is shown in the following tables.

Operational Goal Results:

Gulf Power	**Achievement Percentage**
Customer Satisfaction	133
Reliability	100
Availability	200
Safety	138
Culture	152

Corporate/Southern Company Generation	**Achievement Percentage**
Customer Satisfaction	167
Reliability	174
Availability	170
Safety	200
Culture (Corporate/Southern Company Generation)	138/146

Georgia Power	**Achievement Percentage**
Customer Satisfaction	167
Reliability	171
Availability	77
Safety	163
Culture	141

Southern Nuclear	**Achievement Percentage**
Nuclear Safety	160
Nuclear Reliability	200
Vogtle Units 3 and 4 Assessment	150
Culture	139

Overall, the levels of achievement shown above resulted in an operational goal performance factor for Corporate, Gulf Power, Georgia Power, Southern Company Generation, and Southern Nuclear of 169%, 148%, 143%, 171%, and 157% respectively.

Financial Performance Goal Results:

Goal	**Result**	**Achievement Percentage**
EPS (excluding MCAR insurance recovery)	$2.67	128
Gulf Power ROE	10.92%	46
Georgia Power ROE	12.76%	138
Aggregate ROE	12.55%	122
Southern Power Net Income (excluding $4.5 million from acquisitions)	$171 million	189

Calculating Payouts:

All of the named executive officers are paid based on EPS performance. Ms. Terry and Messrs. Jacob and Teel were employed by Gulf Power for all of 2012 and therefore their annual Performance Pay Program payout is calculated using ROE and operational goal achievement of Gulf Power. Mr. Connally was employed by Gulf Power and Southern Company Generation (supporting Georgia Power) during 2012 and therefore his payout is prorated based on goal achievement for Gulf Power and Southern Company Generation, based on the period of service with each. Mr. Crosswhite was employed by Gulf Power prior to becoming an executive officer of Southern Company and therefore his payout is prorated based on goal achievement for Gulf Power and the corporate/aggregate goal results, based on the period of service with each. Mr. Burroughs was employed by Southern Company Generation (supporting Gulf Power) during 2012. Southern Company Generation officers are paid based on the goal achievement of the traditional operating company supported (60%) and Southern Company Generation (40%). With the exception of the culture goal, Southern Company Generation's operational goal results are the corporate/aggregate results.

A total performance factor is determined by adding the EPS and applicable business unit financial and operational goal performance results and dividing by three. The total performance factor is multiplied by the target Performance Pay Program opportunity, as described above, to determine the payout for each named executive officer.

The table below shows the pay opportunity at target-level performance and the actual payout based on the actual performance shown above.

	Target Annual Performance Pay Program Opportunity ($)	Total Performance Factor (%)	Actual Annual Performance Pay Program Payout ($)
S. W. Connally, Jr.	189,927	119	226,783
M. A. Crosswhite	317,932	125	397,755
R. S. Teel	107,587	107	115,118
M. L. Burroughs	75,680	121	91,572
P. B. Jacob	114,697	105	120,432
B. C. Terry	115,453	107	123,535

Long-Term Performance-Based Compensation

2012 Long-Term Pay Program Highlights

- Stock Options:
  - Reward long-term Common Stock price appreciation
  - Represent 40% of long-term target value
  - Vest over three years
  - Ten-year term
- Performance Shares:
  - Reward total shareholder return relative to industry peers and stock price appreciation
  - Represent 60% of long-term target value
  - Three-year performance period
  - Performance results can range from 0% to 200% of target
  - Paid in Common Stock at end of performance period

Long-term performance-based awards are intended to promote long-term success and increase Southern Company's stockholder value by directly tying a substantial portion of the named executive officers' total compensation to the interests of Southern Company's stockholders. The long-term awards provide an incentive to grow Southern Company's stockholder value.

Stock options represent 40% of the long-term performance target value and performance shares represent the remaining 60%. The Compensation Committee elected this mix because it concluded that doing so represented an appropriate balance between incentives. Stock options only generate value if the price of the stock appreciates after the grant date, and performance shares

reward employees based on Southern Company total shareholder return relative to industry peers, as well as Common Stock price.

The following table shows the grant date fair value of the long-term performance-based awards in total and each component awarded in 2012.

	Value of Options ($)	Value of Performance Shares ($)	Total Long-Term Value ($)
S. W. Connally, Jr.	54,420	81,629	136,049
M. A. Crosswhite	213,994	320,972	534,966
R. S. Teel	57,379	86,038	143,417
M. L. Burroughs	30,269	45,391	75,660
P. B. Jacob	61,169	91,748	152,917
B. C. Terry	61,573	92,336	153,909

Stock Options

Stock options granted have a 10-year term, vest over a three-year period, fully vest upon retirement or termination of employment following a change in control, and expire at the earlier of five years from the date of retirement or the end of the 10-year term. For the grants made in 2012, unvested options are forfeited if the named executive officer retires from the Southern Company system and accepts a position with a peer company within two years of retirement. The value of each stock option was derived using the Black-Scholes stock option pricing model. The assumptions used in calculating that amount are discussed in Note 8 to the financial statements of Gulf Power in Item 8 herein. For 2012, the Black-Scholes value on the grant date was $3.39 per stock option.

Performance Shares

2012-2014 Grant

Performance shares are denominated in units, meaning no actual shares are issued on the grant date. A grant date fair value per unit was determined. For the grant made in 2012, the value per unit was $41.99. See the Summary Compensation Table and the information accompanying it for more information on the grant date fair value. The total target value for performance share units is divided by the value per unit to determine the number of performance share units granted to each participant, including the named executive officers. Each performance share unit represents one share of Common Stock. At the end of the three-year performance period (January 1, 2012 through December 31, 2014), the number of units will be adjusted up or down (0% to 200%) based on Southern Company's total shareholder return relative to that of its peers in the Philadelphia Utility Index and the Southern Company custom peer group. The companies in the custom peer group are those that are believed to be most similar to Southern Company in both business model and investors. The Philadelphia Utility Index was chosen because it is a published index and, because it includes a larger number of peer companies, it can mitigate volatility in results over time, providing an appropriate level of balance. The peer groups vary from the Market Data peer group (as listed on page III-8) due to the timing and criteria of the peer selection process; however, there is significant overlap. The results of the two peer groups will be averaged. The number of performance share units earned will be paid in Common Stock at the end of the three-year performance period. No dividends or dividend equivalents will be paid or earned on the performance share units.

The companies in the Philadelphia Utility Index on the grant date are listed below.

Ameren Corporation	Entergy Corporation
American Electric Power Company, Inc.	Exelon Corporation
CenterPoint Energy, Inc.	FirstEnergy Corp.
Consolidated Edison, Inc.	NextEra Energy, Inc.
Covanta Holding Corporation	Northeast Utilities
Dominion Resources, Inc.	PG&E Corporation
DTE Energy Company	Public Service Enterprise Group Inc.
Duke Energy Corporation	The AES Corporation
Edison International	Xcel Energy Inc.
El Paso Electric Company	

The companies in the custom peer group on the grant date are listed below.

Alliant Energy Corporation	NSTAR
American Electric Power Company, Inc.	PG&E Corporation
CMS Energy Corporation	Pinnacle West Capital Corporation
Consolidated Edison, Inc.	Progress Energy, Inc.
DTE Energy Company	SCANA Corporation
Duke Energy Corporation	Wisconsin Energy Corporation
Edison International	Xcel Energy Inc.
Northeast Utilities	

The scale below will determine the number of units paid in Common Stock following the last year of the performance period, based on the 2012 through 2014 performance period. Payout for performance between points will be interpolated on a straight-line basis.

Performance vs. Peer Group	**Payout (% of Each Performance Share Unit Paid)**
90th percentile or higher	200
50th percentile (Target)	100
10th percentile or lower	0

Performance shares are not earned until the end of the three-year performance period. A participant who terminates, other than due to retirement or death, forfeits all unearned performance shares. Participants who retire or die during the performance period only earn a prorated number of units, based on the number of months they were employed during the performance period.

2010-2012 Payouts

The first performance share grants were made in 2010 with a three-year performance period that ended on December 31, 2012. Based on Southern Company's total shareholder return achievement relative to that of the Philadelphia Utility Index (152.5%) and the customer peer group (117.5%), the payout percentage was 135% of target. The following table shows the target and actual awards of performance shares for the named executive officers.

	Target Performance Shares (#)	**Performance Shares Earned (#)**
S. W. Connally, Jr.	1,472	1,987
M. A. Crosswhite	4,280	5,778
R. S. Teel	1,568	2,117
M. L. Burroughs	401	541
P. B. Jacob	2,848	3,845
B. C. Terry	2,824	3,812

Performance Dividends

The Compensation Committee terminated the Performance Dividend Program in 2010. The value of performance dividends represented a significant portion of long-term performance-based compensation that was awarded prior to 2010. At target performance levels, performance dividends represented up to 65% of the total long-term value granted over the 10-year term of stock options. Therefore, because performance dividends were awarded for years prior to 2010, in fairness to participants, the outstanding performance dividend awards were not cancelled. The Compensation Committee approved a three-year transition period, beginning with the 2007 through 2010 performance-measurement period, to continue to pay performance dividends, if earned, on stock options that were granted prior to 2010. The grant of performance shares, described above, replaced performance dividend awards beginning in 2010. Therefore, the final payout of performance dividends was made on stock options granted prior to 2010 that were outstanding at the end of the four-year performance-measurement period that ended on December 31, 2012, as reported in the Summary Compensation Table. Because performance shares are earned at the end of a three-year performance period, both the last award of performance dividends and the first award of performance shares were

earned at the end of 2012. Performance dividends range from 0% to 100% of the Common Stock dividend paid during the year per eligible stock option held at the end of the performance-measurement period. Actual payout depended on Southern Company's total shareholder return over a four-year performance-measurement period compared to a group of other electric and gas utility companies, as selected at the beginning of the performance-measurement period. The Compensation Committee selected a custom peer group and the Philadelphia Utility Index for the 2009-2012 grant. Total shareholder return is calculated by measuring the ending value of a hypothetical $100 invested in each custom peer group company's common stock and in the Philadelphia Utility Index at the beginning of each of 16 quarters. In the final year of the performance-measurement period, Southern Company's ranking in the peer groups is determined at the end of each quarter and the percentile ranking is multiplied by the actual Common Stock dividend paid in that quarter. To determine the total payout per stock option held at the end of the performance-measurement period, the four quarterly amounts earned are added together.

No performance dividends are paid if Southern Company's earnings are not sufficient to fund a Common Stock dividend at least equal to that paid in the prior year.

2012 Payout

The peer groups used to determine the 2012 payout for the 2009 through 2012 performance-measurement period consisted of the Philadelphia Utility Index and a custom peer group. See the discussion on page III-7 of this CD&A for more information about the selection of the peer groups.

The scale below determined the percentage of each quarter's dividend paid in the last year of the performance-measurement period to be paid on each eligible stock option held at December 31, 2012, based on performance during the 2009 through 2012 performance-measurement period. Payout for performance between points was interpolated on a straight-line basis.

Performance vs. Peer Group	Payout (% of Each Performance Share Unit Paid)
90th percentile or higher	100
50th percentile (Target)	50
10th percentile or lower	0

Southern Company's relative total shareholder return performance, as measured at the end of each quarter of the final year of the four-year performance-measurement period, resulted in a total payout of 70% of the target level (35% of the full year's Common Stock dividend), or $0.68. This amount was multiplied by each named executive officer's eligible outstanding stock options as of December 31, 2012 to calculate the payout under the program. The amount paid is included in the Non-Equity Incentive Plan Compensation column in the Summary Compensation Table.

Timing of Performance-Based Compensation

As discussed above, the 2012 annual Performance Pay Program goals and the total shareholder return goals applicable to performance shares were established early in the year by the Compensation Committee. Annual stock option grants also were made at that meeting. The establishment of performance-based compensation goals and the granting of stock options were not timed with the release of material, non-public information. This procedure is consistent with prior practices. Stock option grants are made to new hires or newly-eligible participants on preset, regular quarterly dates that were approved by the Compensation Committee. The exercise price of options granted to employees in 2012 was the closing price of the Common Stock on the grant date or the last trading day before the grant date, if the grant date was not a trading day.

Retirement and Severance Benefits

Certain post-employment compensation is provided to employees, including the named executive officers.

Retirement Benefits

Generally, all full-time employees of Gulf Power participate in the funded Pension Plan after completing one year of service. Normal retirement benefits become payable when participants attain age 65 and complete five years of participation. Gulf Power also provides unfunded benefits that count salary and annual Performance Pay Program payouts that are ineligible to be counted under the Pension Plan. See the Pension Benefits table and accompanying information for more pension-related benefits information. Gulf Power also provides supplemental retirement benefits to certain employees that were first employed

by Gulf Power, or an affiliate of Gulf Power, in the middle of their careers. Gulf Power has a supplemental retirement agreement (SRA) with both Ms. Terry and Mr. Crosswhite. Prior to their employment, Ms. Terry and Mr. Crosswhite provided legal services to Southern Company's subsidiaries. Ms. Terry's agreement provides retirement benefits as if she was employed an additional 10 years and Mr. Crosswhite's provides an additional 15 years of benefits. Ms. Terry must remain employed at Gulf Power or an affiliate of Gulf Power for 10 years from the effective date of the SRA, before vesting in the benefits. Mr. Crosswhite is vested in the benefits. These agreements provide a benefit which recognizes the expertise both brought to Gulf Power and they provide a strong retention incentive to remain with Gulf Power, or one of its affiliates, for the vesting period and beyond. Gulf Power also provides the Deferred Compensation Plan which is an unfunded plan that permits participants to defer income as well as certain federal, state, and local taxes until a specified date or their retirement, disability, death, or other separation from service. Up to 50% of base salary and up to 100% of performance-based non-equity compensation may be deferred at the election of eligible employees. All of the named executive officers are eligible to participate in the Deferred Compensation Plan. See the Nonqualified Deferred Compensation table and accompanying information for more information about the Deferred Compensation Plan.

Change-in-Control Protections

Change-in-control protections, including severance pay and, in some situations, vesting or payment of long-term performance-based awards, are provided upon a change in control of Southern Company or Gulf Power coupled with an involuntary termination not for cause or a voluntary termination for "Good Reason." This means there is a "double trigger" before severance benefits are paid; *i.e.,* there must be both a change in control and a termination of employment. Severance payment amounts are two times salary plus target Performance Pay Program opportunity for Messrs. Connally and Crosswhite and one times salary plus Performance Pay Program opportunity for the other named executive officers. No excise tax gross-up would be provided. More information about severance arrangements is included in the section entitled Potential Payments upon Termination or Change-in-Control.

Perquisites

Gulf Power provides limited perquisites to its executive officers, including the named executive officers. The perquisites provided in 2012, including amounts, are described in detail in the information accompanying the Summary Compensation Table. No tax assistance is provided on perquisites for Southern Company executive officers, including Mr. Crosswhite and, after June 30, 2012, Mr. Connally, except on certain relocation-related benefits.

EXECUTIVE STOCK OWNERSHIP REQUIREMENTS

Officers of Gulf Power that are in a position of Vice President or above are subject to stock ownership requirements. All of the named executive officers are covered by the requirements. Ownership requirements further align the interest of officers and Southern Company's stockholders by promoting a long-term focus and long-term share ownership. The types of ownership arrangements counted toward the requirements are shares owned outright, those held in Southern Company-sponsored plans, and Common Stock accounts in the Deferred Compensation Plan and the Supplemental Benefit Plan. One-third of vested stock options may be counted, but, if so, the ownership requirement is doubled. The ownership requirement is reduced by one-half at age 60.

The requirements are expressed as a multiple of base salary as shown below.

	Multiple of Salary without Counting Stock Options	Multiple of Salary Counting 1/3 of Vested Options
S. W. Connally, Jr.	3 Times	6 Times
M. A. Crosswhite	3 Times	6 Times
R. S. Teel	2 Times	4 Times
M. L. Burroughs	1 Times	2 Times
P. B. Jacob	2 Times	4 Times
B. C. Terry	2 Times	4 Times

Newly-elected officers have approximately five years from the date of their election to meet the applicable ownership requirement and newly-promoted officers, including Messrs. Connally and Crosswhite, have approximately five years from the date of their promotion to meet the increased ownership requirements. All of the named executive officers are meeting their respective ownership requirement.

POLICY ON RECOVERY OF AWARDS

Southern Company's Omnibus Incentive Compensation Plan provides that, if Southern Company or Gulf Power is required to prepare an accounting restatement due to material noncompliance as a result of misconduct, and if an executive officer of Gulf Power knowingly or grossly negligently engaged in or failed to prevent the misconduct or is subject to automatic forfeiture under the Sarbanes-Oxley Act of 2002, the executive officer will reimburse the amount of any payment in settlement of awards earned or accrued during the 12-month period following the first public issuance or filing that was restated.

POLICY REGARDING HEDGING THE ECONOMIC RISK OF STOCK OWNERSHIP

Southern Company's policy is that employees and outside directors will not trade Southern Company options on the options market and will not engage in short sales.

COMPENSATION COMMITTEE REPORT

The Compensation Committee met with management to review and discuss the CD&A. Based on such review and discussion, the Compensation Committee recommended to the Southern Company Board of Directors that the CD&A be included in the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2012. The Southern Company Board of Directors approved that recommendation.

Members of the Compensation Committee:

Veronica M. Hagen, Chair
Henry A. Clark III
H. William Habermeyer, Jr.
William G. Smith, Jr.

SUMMARY COMPENSATION TABLE

The Summary Compensation Table shows the amount and type of compensation received or earned in 2010, 2011, and 2012 by the named executive officers, except as noted below.

Name and Principal Position (a)	Year (b)	Salary ($) (c)	Bonus ($) (d)	Stock Awards ($) (e)	Option Awards ($) (f)	Non-Equity Incentive Plan Compensation ($) (g)	Change in Pension Value and Nonqualified Deferred Compensation Earnings ($) (h)	All Other Compensation ($) (i)	Total ($) (j)
S. W. Connally, Jr.	2012	295,103	24,376	81,629	54,420	249,526	431,809	179,308	1,316,171
President, Chief Executive Officer, and Director									
M. A. Crosswhite	2012	446,442	41,153	320,972	213,994	468,323	790,434	863,157	3,144,475
Executive Vice President and Chief Operating Officer of Southern Company	2011	395,937	38,791	311,608	207,760	384,016	366,993	480,990	2,186,095
R. S. Teel	2012	236,882	—	86,038	57,379	143,335	118,474	15,610	657,718
Vice President and Chief Financial Officer	2011	225,993	—	81,760	54,516	156,624	72,473	14,773	606,139
	2010	205,540	22,056	47,244	31,508	171,316	50,082	448,620	976,366
M. L. Burroughs	2012	187,855	—	45,391	30,269	94,634	204,035	12,218	574,402
Vice President	2011	180,684	—	43,632	29,107	102,255	135,314	49,366	540,358
	2010	150,745	24,612	12,082	8,073	95,255	94,324	220,820	605,911
P. B. Jacob	2012	253,959	—	91,748	61,169	145,616	310,532	16,671	879,695
Vice President	2011	249,188	—	89,925	59,969	159,207	233,428	15,714	807,431
	2010	239,444	—	85,810	57,217	172,892	176,201	19,021	750,585
B. C. Terry	2012	255,634	—	92,336	61,573	159,332	210,941	16,910	796,726
Vice President	2011	250,194	—	90,536	60,366	182,994	122,604	15,957	722,651
	2010	237,466	—	85,087	56,742	183,929	259,023	22,542	844,789

Column (a)

Mr. Connally was not an executive officer of Gulf Power prior to 2012, and Mr. Crosswhite was not an executive officer of Gulf Power prior to 2011. Mr. Crosswhite served as President and Chief Executive Officer of Gulf Power through June 2012.

Column (d)

The amounts shown for 2012 for Messrs. Connally and Crosswhite are geographic relocation incentives that were paid in connection with their relocations. The relocation incentive equaled 10% of salary rate as of the date of relocation.

Column (e)

This column does not reflect the value of stock awards that were actually earned or received in 2012. Rather, as required by applicable rules of the SEC, this column reports the aggregate grant date fair value of performance shares granted in 2012. The value reported is based on the probable outcome of the performance conditions as of the grant date, using a Monte Carlo simulation model. No amounts will be earned until the end of the three-year performance period on December 31, 2014. The value then can be earned based on performance ranging from 0 to 200%, as established by the Compensation Committee. The aggregate grant date fair value of the performance shares granted in 2012 to Ms. Terry and Messrs. Connally, Crosswhite, Teel, Burroughs, and Jacob, assuming the highest level of performance is achieved, is $184,672, $163,257, $641,943, $172,075, $90,782, and $183,496, respectively (200% of the amount shown in the table). See Note 8 to the financial statements of Gulf Power in Item 8 herein for a discussion of the assumptions used in calculating these amounts.

Column (f)

This column reports the aggregate grant date fair value of stock options. See Note 8 to the financial statements of Gulf Power in Item 8 herein for a discussion of the assumptions used in calculating these amounts.

Column (g)

The amounts in this column are the aggregate of the payouts under the annual Performance Pay Program and the Performance Dividend Program. The amount reported for the Performance Pay Program is for the one-year performance period that ended December 31, 2012. The amount reported for performance dividends is the amount earned at the end of the four-year performance-measurement period of January 1, 2009 through December 31, 2012. These awards were granted by the Compensation Committee in 2009 and are paid on stock options granted prior to 2010 that were outstanding at the end of 2012. As described in the CD&A, the Performance Dividend Program was eliminated by the Compensation Committee in 2010 and replaced with performance shares. This payout reported in column (g) is the third and final payout in the three-year transition period as described in the CD&A. The Performance Pay Program, the Performance Dividend Program, and performance shares are described in detail in the CD&A.

The amounts paid under each program to the named executive officers are shown below.

	Annual Performance-Based Compensation ($)	Performance Dividends ($)	Total ($)
S. W. Connally, Jr.	226,783	22,743	249,526
M. A. Crosswhite	397,755	70,568	468,323
R. S. Teel	115,118	28,217	143,335
M. L. Burroughs	91,572	3,062	94,634
P. B. Jacob	120,432	25,184	145,616
B. C. Terry	123,535	35,797	159,332

Column (h)

This column reports the aggregate change in the actuarial present value of each named executive officer's accumulated benefit under the Pension Plan and the supplemental pension plans (collectively, Pension Benefits) as of December 31, 2010, 2011, and 2012. The Pension Benefits as of each measurement date are based on the named executive officer's age, pay, and service accruals and the plan provisions applicable as of the measurement date. The actuarial present values as of each measurement date reflect the assumptions Gulf Power selected for cost purposes as of that measurement date; however, the named executive officers were assumed to remain employed at Gulf Power or any other Southern Company subsidiary until their benefits commence at the pension plans' stated normal retirement date, generally age 65. As a result, the amounts in column (h) related to Pension Benefits represent the combined impact of several factors: growth in the named executive officer's Pension Benefits over the measurement year; impact on the total present values of one year shorter discounting period due to the named executive officer being one year closer to normal retirement; impact on the total present values attributable to changes in assumptions from measurement date to measurement date; and impact on the total present values attributable to plan changes between measurement dates.

For more information about the Pension Benefits and the assumptions used to calculate the actuarial present value of accumulated benefits as of December 31, 2012, see the information following the Pension Benefits table. The key differences between assumptions used for the actuarial present values of accumulated benefits calculations as of December 31, 2011 and December 31, 2012 are:

- Discount rate for the Pension Plan was decreased to 4.30% as of December 31, 2012 from 5.0% as of December 31, 2011.
- Discount rate for the supplemental pension plans was decreased to 3.70% as of December 31, 2012 from 4.65% as of December 31, 2011.

This column also reports above-market earnings on deferred compensation under the Deferred Compensation Plan (DCP). However, there were no above-market earnings on deferred compensation in the years reported.

Column (i)

This column reports the following items: perquisites; tax reimbursements on certain perquisites; employer contributions in 2012 to the Southern Company Employee Savings Plan (ESP), which is a tax-qualified defined contribution plan intended to meet requirements of Section 401(k) of the Internal Revenue Code of 1986, as amended (Code); and contributions in 2012 under the Southern Company Supplemental Benefit Plan (Non-Pension Related) (SBP). The SBP is described more fully in the information following the Nonqualified Deferred Compensation table.

The amounts reported are itemized below.

	Perquisites ($)	Tax Reimbursements ($)	ESP ($)	SBP ($)	Total ($)
S. W. Connally, Jr.	148,057	16,200	12,108	2,943	179,308
M. A. Crosswhite	557,403	283,322	12,413	10,019	863,157
R. S. Teel	4,628	90	10,892	—	15,610
M. L. Burroughs	2,451	186	9,581	—	12,218
P. B. Jacob	5,149	368	10,952	202	16,671
B. C. Terry	5,392	288	10,943	287	16,910

Description of Perquisites

Personal Financial Planning is provided for most officers of Gulf Power, including all of the named executive officers. Gulf Power pays for the services of the financial planner on behalf of the officers, up to a maximum amount of $8,700 per year, after the initial year that the benefit is provided. In the initial year, the allowed amount is $15,000. Gulf Power also provides a five-year allowance of $6,000 for estate planning and tax return preparation fees.

Relocation Benefits. These benefits are provided to cover the costs associated with geographic relocation. Mr. Connally relocated from Atlanta, Georgia to Pensacola, Florida in 2012. Mr. Crosswhite relocated from Pensacola, Florida to Birmingham, Alabama in 2012. During 2012, Messrs. Connally and Crosswhite received relocation-related benefits in the amounts of $134,551 and $547,666, respectively. Relocation assistance includes the incremental cost paid or incurred for relocation, including loss on home sale and certain capital improvements of the residence in the former location, if applicable, home sale and home repurchase assistance (closing costs), shipment of household goods, temporary housing costs during the move, and in some cases, a lump sum relocation allowance, in lieu of the payment of certain relocation benefits. Under the relocation policy applicable to all employees, any loss on home sale is determined based on the purchase price paid for the residence plus the cost of capital improvements made within the last five years to the residence that qualify for addition to the tax basis of the residence. Also, as provided in the policy, tax assistance is provided on the taxable relocation benefits, including the reimbursement for loss on home sale. For Mr. Crosswhite, if he terminates within two years of his relocation, the amount provided for loss on home sale, including tax assistance, must be repaid. If Mr. Connally terminates within two years of his relocation, the amount provided for loss on home sale, including tax assistance, must be repaid.

Personal Use of Corporate-Owned Aircraft. Southern Company owns aircraft that are used to facilitate business travel. If seating is available, Southern Company permits a spouse or other family member to accompany an employee on a flight. However, because in such cases the aircraft is being used for a business purpose, there is no incremental cost associated with the family travel and no amounts are included for such travel. Any additional expenses incurred that are related to family travel are included. In connection with Mr. Connally's relocation, the Compensation Committee approved personal use of corporate-owned aircraft for a weekly round-trip between Atlanta and Pensacola for the first six months following his relocation to Pensacola. In connection with Mr. Crosswhite's relocation, the Compensation Committee approved personal use of corporate-owned aircraft for a weekly round-trip between Birmingham and Pensacola for the first six months following his relocation to Birmingham.

Other Miscellaneous Perquisites. The amount included reflects the full cost to Gulf Power of providing the following items: personal use of company-provided tickets for sporting and other entertainment events and gifts distributed to and activities provided to attendees at company-sponsored events.

GRANTS OF PLAN-BASED AWARDS IN 2012

This table provides information on stock option grants made and goals established for future payouts under the performance-based compensation programs during 2012 by the Compensation Committee.

Name (a)	Grant Date (b)	Estimated Possible Payouts Under Non-Equity Incentive Plan Awards			Estimated Future Payouts Under Equity Incentive Plan Awards			All Other Option Awards: Number of Securities Underlying Options (#) (i)	Exercise or Base Price of Option Awards ($/Sh) (j)	Grant Date Fair Value of Stock and Option Awards ($) (k)
		Threshold ($) (c)	Target ($) (d)	Maximum ($) (e)	Threshold (#) (f)	Target (#) (g)	Maximum (#) (h)			
S. W. Connally, Jr.	2/13/2012	1,899	189,927	379,854						
	2/13/2012				19	1,944	3,888			81,629
	2/13/2012							16,053	44.42	54,420
M. A. Crosswhite	2/13/2012	3,179	317,932	635,864						
	2/13/2012				76	7,644	15,288			320,972
	2/13/2012							63,125	44.42	213,994
R. S. Teel	2/13/2012	1,076	107,587	215,174						
	2/13/2012				20	2,049	4,098			86,038
	2/13/2012							16,926	44.42	57,379
M. L. Burroughs	2/13/2012	757	75,680	151,360						
	2/13/2012				11	1,081	2,162			45,391
	2/13/2012							8,929	44.42	30,269
P. B. Jacob	2/13/2012	1,147	114,697	229,394						
	2/13/2012				22	2,185	4,370			91,748
	2/13/2012							18,044	44.42	61,169
B. C. Terry	2/13/2012	1,155	115,453	230,906						
	2/13/2012				22	2,199	4,398			92,336
	2/13/2012							18,163	44.42	61,573

Columns (c), (d), and (e)

These columns reflect the annual Performance Pay Program opportunity granted to the named executive officers in 2012 as described in the CD&A. The information shown as "Threshold," "Target," and "Maximum" reflects the range of potential payouts established by the Compensation Committee. The actual amounts earned are disclosed in the Summary Compensation Table.

Columns (f), (g), and (h)

These columns reflect the performance shares granted to the named executive officers in 2012 as described in the CD&A. The information shown as "Threshold," "Target," and "Maximum" reflects the range of potential payouts established by the Compensation Committee. Earned performance shares will be paid out in Common Stock following the end of the 2012-2014 performance period, based on the extent to which the performance goals are achieved. Any shares not earned are forfeited.

Columns (i) and (j)

Column (i) reflects the number of stock options granted to the named executive officers in 2012, as described in the CD&A, and column (j) reflects the exercise price of the stock options, which was the closing price on the grant date.

Column (k)

This column reflects the aggregate grant date fair value of the performance shares and stock options granted in 2012. For performance shares, the value is based on the probable outcome of the performance conditions as of the grant date using a Monte Carlo simulation model. For stock options, the value is derived using the Black-Scholes stock option pricing model.

The assumptions used in calculating these amounts are discussed in Note 8 to the financial statements of Gulf Power in Item 8 herein.

OUTSTANDING EQUITY AWARDS AT 2012 FISCAL YEAR-END

This table provides information pertaining to all outstanding stock options and stock awards (performance shares) held by or granted to the named executive officers as of December 31, 2012.

	Option Awards				Stock Awards	
Name	Number of Securities Underlying Unexercised Options Exercisable (#) (b)	Number of Securities Underlying Unexercised Options Unexercisable (#) (c)	Option Exercise Price ($) (d)	Option Expiration Date (e)	Equity Incentive Plan Awards: Number of Unearned Shares, Units or Other Rights That Have Not Vested (#) (f)	Equity Incentive Plan Awards: Market or Payout Value of Unearned Shares, Units or Other Rights That Have Not Vested ($) (g)
S. W. Connally, Jr.						
	5,096		33.81	02/20/2016		
	5,437		36.42	02/19/2017		
	8,521		35.78	02/18/2018		
	14,392		31.39	02/16/2019		
	6,841	4,421	31.17	02/15/2020		
	5,367	10,733	37.97	02/14/2021	4,364	186,823
	0	16,053	44.42	02/13/2022	3,888	166,455
M. A. Crosswhite						
	16,497		33.81	02/20/2016		
	22,578		36.42	02/19/2017		
	22,460		35.78	02/18/2018		
	42,242		31.39	02/16/2019		
	12,851	12,851	31.17	02/15/2020		
	21,309	42,617	37.97	02/14/2021	17,326	741,726
	0	63,125	44.42	02/13/2022	15,288	654,479
R. S. Teel	2,050		32.70	02/18/2015		
	5,771		33.81	02/20/2016		
	9,265		36.42	02/19/2017		
	9,078		35.78	02/18/2018		
	15,332		31.39	02/16/2019		
	4,919	4,710	31.17	02/15/2020		
	5,592	11,182	37.97	02/14/2021	4,546	194,614
	0	16,926	44.42	02/13/2022	4,098	175,435
M. L. Burroughs						
	289		33.81	02/20/2016		
	1,604		36.42	02/19/2017		
	2,610		35.78	02/18/2018		
	0	1,207	31.17	02/15/2020		
	2,986	5,970	37.97	02/14/2021	2,426	103,857
	0	8,929	44.42	02/13/2022	2,162	92,555
P. B. Jacob	13,925		36.42	02/19/2017		
	13,785		35.78	02/18/2018		
	9,326		31.39	02/16/2019		
	7,254	8,553	31.17	02/15/2020		
	0	12,301	37.97	02/14/2021	5,000	214,050
	0	18,044	44.42	02/13/2022	4,370	187,080
B. C. Terry	8,905		33.81	02/20/2016		
	9,367		36.42	02/19/2017		
	12,918		35.78	02/18/2018		
	21,453		31.39	02/16/2019		
	0	8,482	31.17	02/15/2020		
	6,192	12,382	37.97	02/14/2021	5,034	215,506
	0	18,163	44.42	02/13/2022	4,398	188,278

Columns (b), (c), (d), and (e)

Stock options vest one-third per year on the anniversary of the grant date. Options granted from 2005 through 2009 with expiration dates from 2015 through 2019 were fully vested as of December 31, 2012. The options granted in 2010, 2011, and 2012 become fully vested as shown below.

Year Option Granted	Expiration Date	Date Fully Vested
2010	February 15, 2020	February 15, 2013
2011	February 14, 2021	February 14, 2014
2012	February 13, 2022	February 13, 2015

Options also fully vest upon death, total disability, or retirement and expire three years following death or total disability or five years following retirement, or on the original expiration date if earlier. See Potential Payments upon Termination or Change in Control for more information about the treatment of stock options under different termination and change-in-control events.

Columns (f) and (g)

In accordance with SEC rules, column (f) reflects the maximum number of performance shares that can be earned at the end of each three-year performance period (December 31, 2013 and 2014) that were granted in 2011 and 2012, respectively. The performance shares granted for the 2010-2012 performance period vested December 31, 2012 and are shown in the Option Exercises and Stock Vested in 2012 table below. The value in column (g) is derived by multiplying the number of shares in column (f) by the Common Stock closing price on December 31, 2012 ($42.81). The ultimate number of shares earned, if any, will be based on the actual performance results at the end of each respective performance period. See further discussion of performance shares in the CD&A.

OPTION EXERCISES AND STOCK VESTED IN 2012

	Option Awards		Stock Awards	
Name (a)	Number of Shares Acquired on Exercise (#) (b)	Value Realized on Exercise ($) (c)	Number of Shares Acquired on Vesting (#) (d)	Value Realized on Vesting ($) (e)
S. W. Connally, Jr.	7,353	104,842	1,987	85,063
M. A. Crosswhite	17,660	227,531	5,778	247,356
R. S. Teel	8,000	117,695	2,117	90,629
M. L. Burroughs	6,587	97,275	541	23,160
P. B. Jacob	13,151	167,074	3,845	164,604
B. C. Terry	14,772	220,759	3,812	163,192

Columns (b) and (c)

Column (b) reflects the number of shares acquired upon the exercise of stock options during 2012 and column (c) reflects the value realized. The value realized is the difference in the market price over the exercise price on the exercise date.

Columns (d) and (e)

Column (d) includes the performance shares awarded for the 2010-2012 performance period that vested on December 31, 2012. The value reflected in column (e) is derived by multiplying the number of shares in column (d) by the market value of the underlying shares on the vesting date ($42.81).

PENSION BENEFITS AT 2012 FISCAL YEAR-END

Name	Plan Name	Number of Years Credited Service (#)	Present Value of Accumulated Benefit ($)	Payments During Last Fiscal Year ($)
(a)	(b)	(c)	(d)	(e)
	Pension Plan	21.17	407,146	0
	SBP-P	21.17	165,494	0
S.W. Connally, Jr.	SERP	21.17	276,495	0
	Pension Plan	7.92	220,898	0
	SBP-P	7.92	275,275	0
	SERP	7.92	212,207	0
M. A. Crosswhite	SRA	15.00	1,436,775	0
	Pension Plan	12.33	237,732	0
	SBP-P	12.33	35,828	0
R. S. Teel	SERP	12.33	83,964	0
	Pension Plan	20.58	447,509	0
	SBP-P	20.58	43,234	0
M. L. Burroughs	SERP	20.58	157,502	0
	Pension Plan	29.42	1,114,934	0
	SBP-P	29.42	258,837	0
P. B. Jacob	SERP	29.42	298,205	0
	Pension Plan	10.50	223,707	0
	SBP-P	10.50	39,955	0
	SERP	10.50	73,005	0
B. C. Terry	SRA	10.00	368,454	0

Pension Plan

The Pension Plan is a tax-qualified, funded plan. It is Southern Company's primary retirement plan. Generally, all full-time employees participate in this plan after one year of service. Normal retirement benefits become payable when participants attain age 65 and complete five years of participation. The plan benefit equals the greater of amounts computed using a "1.7% offset formula" and a "1.25% formula," as described below. Benefits are limited to a statutory maximum.

The 1.7% offset formula amount equals 1.7% of final average pay times years of participation less an offset related to Social Security benefits. The offset equals a service ratio times 50% of the anticipated Social Security benefits in excess of $4,200. The service ratio adjusts the offset for the portion of a full career that a participant has worked. The highest three rates of pay out of a participant's last 10 calendar years of service are averaged to derive final average pay. The pay considered for this formula is the base salary rate with no adjustments for voluntary deferrals after 2008. A statutory limit restricts the amount considered each year; the limit for 2012 was $250,000.

The 1.25% formula amount equals 1.25% of final average pay times years of participation. For this formula, the final average pay computation is the same as above, but annual performance-based compensation earned each year is added to the base rates of pay.

Early retirement benefits become payable once plan participants have, during employment, attained age 50 and completed 10 years of participation. Participants who retire early from active service receive benefits equal to the amounts computed using the same formulas employed at normal retirement. However, a 0.3% reduction applies for each month (3.6% for each year) prior to normal retirement that participants elect to have their benefit payments commence. For example, 64% of the formula benefits are payable starting at age 55. As of December 31, 2012, Ms. Terry and Messrs. Connally, Crosswhite, and Teel were not retirement-eligible.

The Pension Plan's benefit formulas produce amounts payable monthly over a participant's post-retirement lifetime. At retirement, plan participants can choose to receive their benefits in one of seven alternative forms of payment. All forms pay benefits monthly over the lifetime of the retiree or the joint lifetimes of the retiree and a spouse. A reduction applies if a retiring participant chooses a payment form other than a single life annuity. The reduction makes the value of the benefits paid in the form chosen comparable to what it would have been if benefits were paid as a single life annuity over the retiree's life. Participants vest in the Pension Plan after completing five years of service. All the named executive officers are vested in their Pension Plan benefits. Participants who terminate employment after vesting can elect to have their pension benefits commence

at age 50 if they participated in the Pension Plan for 10 years. If such an election is made, the early retirement reductions that apply are actuarially determined factors and are larger than 0.3% per month.

If a participant dies while actively employed and is either age 50 or vested in the Pension Plan as of date of death, benefits will be paid to a surviving spouse. A survivor's benefit equals 45% of the monthly benefit that the participant had earned before his or her death. Payments to a surviving spouse of a participant who could have retired will begin immediately. Payments to a survivor of a participant who was not retirement-eligible will begin when the deceased participant would have attained age 50.

After commencing, survivor benefits are payable monthly for the remainder of a survivor's life. Participants who are eligible for early retirement may opt to have an 80% survivor benefit paid if they die; however, there is a charge associated with this election.

If participants become totally disabled, periods that Social Security or employer-provided disability income benefits are paid will count as service for benefit calculation purposes. The crediting of this additional service ceases at the point a disabled participant elects to commence retirement payments. Outside of this extra service crediting, the normal plan provisions apply to disabled participants.

The Southern Company Supplemental Benefit Plan (Pension-Related) (SBP-P)

The SBP-P is an unfunded retirement plan that is not tax qualified. This plan provides high-paid employees any benefits that the Pension Plan cannot pay due to statutory pay/benefit limits. The SBP-P's vesting and early retirement provisions mirror those of the Pension Plan. Its disability provisions mirror those of the Pension Plan but cease upon a participant's separation from service.

The amounts paid by the SBP-P are based on the additional monthly benefit that the Pension Plan would pay if the statutory limits and pay deferrals were ignored. When an SBP-P participant separates from service, vested monthly benefits provided by the benefit formulas are converted into a single sum value. It equals the present value of what would have been paid monthly for an actuarially determined average post-retirement lifetime. The discount rate used in the calculation is based on the 30-year U.S. Treasury yields for the September preceding the calendar year of separation, but not more than six percent.

Vested participants terminating prior to becoming eligible to retire will be paid their single sum value as of September 1 following the calendar year of separation. If the terminating participant is retirement eligible, the single sum value will be paid in 10 annual installments starting shortly after separation. The unpaid balance of a retiree's single sum will be credited with interest at the prime rate published in *The Wall Street Journal*. If the separating participant is a "key man" under Section 409A of the Code, the first installment will be delayed for six months after the date of separation.

If an SBP-P participant dies after becoming vested in the Pension Plan, the spouse of the deceased participant will receive the installments the participant would have been paid upon retirement. If a vested participant's death occurs prior to age 50, the installments will be paid to a spouse as if the participant had survived to age 50.

The Southern Company Supplemental Executive Retirement Plan (SERP)

The SERP is also an unfunded retirement plan that is not tax qualified. This plan provides high-paid employees additional benefits that the Pension Plan and the SBP-P would pay if the 1.7% offset formula calculations reflected a portion of annual performance-based compensation. To derive the SERP benefits, a final average pay is determined reflecting participants' base rates of pay and their annual performance-based compensation amounts, whether or not deferred, to the extent they exceed 15% of those base rates (ignoring statutory limits). This final average pay is used in the 1.7% offset formula to derive a gross benefit. The Pension Plan and the SBP-P benefits are subtracted from the gross benefit to calculate the SERP benefit. The SERP's early retirement, survivor benefit, disability, and form of payment provisions mirror the SBP-P's provisions. However, except upon a change in control, SERP benefits do not vest until participants retire, so no benefits are paid if a participant terminates prior to becoming retirement-eligible. More information about vesting and payment of SERP benefits following a change in control is included in the section entitled "Potential Payments upon Termination or Change in Control."

Supplemental Pension Benefit Agreements (SRA)

Gulf Power also provides supplemental retirement benefits to certain employees that were first employed by Gulf Power, or an affiliate of Gulf Power, in the middle of their careers and generally provide for additional retirement benefits by giving credit for years of employment prior to employment with Gulf Power or one of its affiliates. Information about the supplemental retirement agreements with Ms. Terry and Mr. Crosswhite is included in the CD&A.

The following assumptions were used in the present value calculations for pension benefits:

- Discount rate - 4.30% Pension Plan and 3.70% supplemental plans as of December 31, 2012
- Retirement date - Normal retirement age (65 for all named executive officers)
- Mortality after normal retirement - RP2000 Combined Healthy with generational projections
- Mortality, withdrawal, disability, and retirement rates prior to normal retirement - None
- Form of payment for Pension Benefits:
  - Male retirees: 25% single life annuity; 25% level income annuity; 25% joint and 50% survivor annuity; and 25% joint and 100% survivor annuity
  - Female retirees: 40% single life annuity; 40% level income annuity; 10% joint and 50% survivor annuity; and 10% joint and 100% survivor annuity
- Spouse ages - Wives two years younger than their husbands
- Annual performance-based compensation earned but unpaid as of the measurement date - 130% of target opportunity percentages times base rate of pay for year amount is earned
- Installment determination - 3.75% discount rate for single sum calculation and 4.50% prime rate during installment payment period

For all of the named executive officers, the number of years of credited service for the Pension Plan, the SBP-P, and the SERP is one year less than the number of years of employment.

NONQUALIFIED DEFERRED COMPENSATION AS OF 2012 FISCAL YEAR-END

Name (a)	Executive Contributions in Last FY ($) (b)	Registrant Contributions in Last FY ($) (c)	Aggregate Earnings in Last FY ($) (d)	Aggregate Withdrawals/ Distributions ($) (e)	Aggregate Balance at Last FYE ($) (f)
S. W. Connally, Jr.	20,370	2,943	2,686	—	90,622
M. A. Crosswhite	—	10,019	3,634	—	197,784
R. S. Teel	—	—	(5)	—	129
M. L. Burroughs	—	—	—	—	—
P. B. Jacob	38,888	202	15,326	—	382,335
B. C. Terry	60,557	287	4,005	—	138,171

Southern Company provides the DCP which is designed to permit participants to defer income as well as certain federal, state, and local taxes until a specified date or their retirement, or other separation from service. Up to 50% of base salary and up to 100% of performance-based non-equity compensation may be deferred at the election of eligible employees. All of the named executive officers are eligible to participate in the DCP.

Participants have two options for the deemed investments of the amounts deferred - the Stock Equivalent Account and the Prime Equivalent Account. Under the terms of the DCP, participants are permitted to transfer between investments at any time. The amounts deferred in the Stock Equivalent Account are treated as if invested at an equivalent rate of return to that of an actual investment in Common Stock, including the crediting of dividend equivalents as such are paid by Southern Company from time to time. It provides participants with an equivalent opportunity for the capital appreciation (or loss) and income of that of a Southern Company stockholder. During 2012, the rate of return in the Stock Equivalent Account was -3.4% which was Southern Company's total shareholder return for 2012.

Alternatively, participants may elect to have their deferred compensation deemed invested in the Prime Equivalent Account which is treated as if invested at a prime interest rate compounded monthly, as published in *The Wall Street Journal* as the base rate on corporate loans posted as of the last business day of each month by at least 75% of the United States' largest banks. The interest rate earned on amounts deferred during 2012 in the Prime Equivalent Account was 3.25%.

Column (b)

This column reports the actual amounts of compensation deferred under the DCP by each named executive officer in 2012. The amount of salary deferred by the named executive officers, if any, is included in the Salary column in the Summary Compensation Table. The amounts of performance-based compensation deferred in 2012 were the amounts paid for performance under the annual Performance Pay Program and the Performance Dividend Program that were earned as of December 31, 2011 but not payable until the first quarter of 2012. These amounts are not reflected in the Summary Compensation Table because that table reports performance-based compensation that was earned in 2012, but not payable until early 2013. These deferred amounts may be distributed in a lump sum or in up to 10 annual installments at termination of employment or in a lump sum at a specified date, at the election of the participant.

Column (c)

This column reflects contributions under the SBP. Under the Code, employer matching contributions are prohibited under the ESP on employee contributions above stated limits in the ESP, and, if applicable, above legal limits set forth in the Code. The SBP is a nonqualified deferred compensation plan under which contributions are made that are prohibited from being made in the ESP. The contributions are treated as if invested in Common Stock and are payable in cash upon termination of employment in a lump sum or in up to 20 annual installments, at the election of the participant. The amounts reported in this column also were reported in the All Other Compensation column in the Summary Compensation Table.

Column (d)

This column reports earnings or losses on both compensation the named executive officers elected to defer and on employer contributions under the SBP.

Column (f)

This column includes amounts that were deferred under the DCP and contributions under the SBP in prior years and reported in Gulf Power's prior years' Information Statements or Annual Reports on Form 10-K. The chart below shows the amounts reported in Gulf Power's prior years' Information Statements or Annual Reports on Form 10-K.

Name	Amounts Deferred under the DCP Prior to 2012 and Reported in Prior Years' Information Statements or Annual Reports on Form 10-K ($)	Employer Contributions under the SBP Prior to 2012 and Reported in Prior Years' Information Statements or Annual Reports on Form 10-K ($)	Total ($)
S. W. Connally, Jr.	—	—	—
M. A. Crosswhite	23,316	7,698	31,014
R. S. Teel	—	—	—
M. L. Burroughs	—	—	—
P. B. Jacob	218,217	22,888	241,105
B. C. Terry	121,427	265	121,692

POTENTIAL PAYMENTS UPON TERMINATION OR CHANGE IN CONTROL

This section describes and estimates payments that could be made to the named executive officers under different termination and change-in-control events. The estimated payments would be made under the terms of Southern Company's compensation and benefit program or the change-in-control severance program. All of the named executive officers are participants in Southern Company's change-in-control severance program for officers. The amount of potential payments is calculated as if the triggering events occurred as of December 31, 2012 and assumes that the price of Common Stock is the closing market price on December 31, 2012.

Description of Termination and Change-in-Control Events

The following charts list different types of termination and change-in-control events that can affect the treatment of payments under the compensation and benefit programs. No payments are made under the change-in-control severance program unless, within two years of the change in control, the named executive officer is involuntarily terminated or voluntarily terminates for Good Reason. (See the description of Good Reason below.)

Traditional Termination Events

- Retirement or Retirement-Eligible - Termination of a named executive officer who is at least 50 years old and has at least 10 years of credited service.
- Resignation - Voluntary termination of a named executive officer who is not retirement-eligible.
- Lay Off - Involuntary termination of a named executive officer who is not retirement-eligible not for cause.
- Involuntary Termination - Involuntary termination of a named executive officer for cause. Cause includes individual performance below minimum performance standards and misconduct, such as violation of Gulf Power's Drug and Alcohol Policy.
- Death or Disability - Termination of a named executive officer due to death or disability.

Change-in-Control-Related Events

At the Southern Company or Gulf Power level:

- Southern Company Change-in-Control I - Acquisition by another entity of 20% or more of Common Stock, or following a merger with another entity Southern Company's stockholders own 65% or less of the entity surviving the merger.
- Southern Company Change-in-Control II - Acquisition by another entity of 35% or more of Common Stock, or following a merger with another entity Southern Company shareholders own less than 50% of Southern Company surviving the merger.
- Southern Company Termination - A merger or other event and Southern Company is not the surviving company or the Common Stock is no longer publicly traded.
- Gulf Power Change in Control - Acquisition by another entity, other than another subsidiary of Southern Company, of 50% or more of the stock of Gulf Power, a merger with another entity and Gulf Power is not the surviving company, or the sale of substantially all the assets of Gulf Power.

At the employee level:

- Involuntary Change-in-Control Termination or Voluntary Change-in-Control Termination for Good Reason - Employment is terminated within two years of a change in control, other than for cause, or the employee voluntarily terminates for Good Reason. Good Reason for voluntary termination within two years of a change in control generally is satisfied when there is a material reduction in salary, performance-based compensation opportunity or benefits, relocation of over 50 miles, or a diminution in duties and responsibilities.

The following chart describes the treatment of different pay and benefit elements in connection with the Traditional Termination Events described above.

Program	Retirement/ Retirement-Eligible	Lay Off (Involuntary Termination Not For Cause)	Resignation	Death or Disability	Involuntary Termination (For Cause)
Pension Benefits Plans	Benefits payable as described in the notes following the Pension Benefits table.	Same as Retirement.	Same as Retirement.	Same as Retirement.	Same as Retirement.
Annual Performance Pay Program	Prorated if retire before 12/31.	Same as Retirement.	Forfeit.	Same as Retirement.	Forfeit.
Performance Dividend Program	Paid year of retirement plus two additional years.	Forfeit.	Forfeit.	Payable until options expire or exercised.	Forfeit.
Stock Options	Vest; expire earlier of original expiration date or five years.	Vested options expire in 90 days; unvested are forfeited.	Same as Lay Off.	Vest; expire earlier of original expiration date or three years.	Forfeit.
Performance Shares	Prorated if retire prior to end of performance period.	Forfeit.	Forfeit.	Same as Retirement.	Forfeit.
Financial Planning Perquisite	Continues for one year.	Terminates.	Terminates.	Same as Retirement.	Terminates.
Deferred Compensation Plan	Payable per prior elections (lump sum or up to 10 annual installments).	Same as Retirement.	Same as Retirement.	Payable to beneficiary or participant per prior elections. Amounts deferred prior to 2005 can be paid as a lump sum per benefit administration committee's discretion.	Same as Retirement.
Supplemental Benefit Plan - non-pension related	Payable per prior elections (lump sum or up to 20 annual installments).	Same as Retirement.	Same as Retirement.	Same as the Deferred Compensation Plan.	Same as Retirement.

The chart below describes the treatment of payments under compensation and benefit programs under different change-in-control events, except the Pension Plan. The Pension Plan is not affected by change-in-control events.

Program	Southern Company Change-in-Control I	Southern Company Change-in-Control II	Southern Company Termination or Gulf Power Change in Control	Involuntary Change-in-Control-Related Termination or Voluntary Change-in-Control-Related Termination for Good Reason
Nonqualified Pension Benefits	All SERP-related benefits vest if participants vested in tax-qualified pension benefits; otherwise, no impact. SBP - pension- related benefits vest for all participants and single sum value of benefits earned to change-in-control date paid following termination or retirement.	Benefits vest for all participants and single sum value of benefits earned to the change-in-control date paid following termination or retirement.	Same as Southern Company Change-in-Control II.	Based on type of change-in-control event.
Annual Performance Pay Program	If no program termination, paid at greater of target or actual performance. If program terminated within two years of change in control, prorated at target performance level.	Same as Southern Company Change-in-Control I.	Prorated at target performance level.	If not otherwise eligible for payment, if the program is still in effect, prorated at target performance level.
Performance Dividend Program	If no program termination, paid at greater of target or actual performance. If program terminated within two years of change in control, prorated at greater of target or actual performance level.	Same as Southern Company Change-in-Control I.	Prorated at greater of actual or target performance level.	If not otherwise eligible for payment, if the program is still in effect, greater of actual or target performance level for year of severance only.
Stock Options	Not affected by change-in-control events.	Not affected by change-in-control events.	Vest and convert to surviving company's securities; if cannot convert, pay spread in cash.	Vest.
Performance Shares	Not affected by change-in-control events.	Not affected by change-in-control events.	Vest and convert to surviving company's securities; if cannot convert, pay spread in cash.	Vest.
DCP	Not affected by change-in-control events.	Not affected by change-in-control events.	Not affected by change-in-control events.	Not affected by change-in-control events.

Program	Southern Company Change-in-Control I	Southern Company Change-in-Control II	Southern Company Termination or Gulf Power Change in Control	Involuntary Change-in-Control-Related Termination or Voluntary Change-in-Control-Related Termination for Good Reason
SBP	Not affected by change-in-control events.	Not affected by change-in-control events.	Not affected by change-in-control events.	Not affected by change-in-control events.
Severance Benefits	Not applicable.	Not applicable.	Not applicable.	One or two times base salary plus target annual performance-based pay.
Healthcare Benefits	Not applicable.	Not applicable.	Not applicable.	Up to five years participation in group healthcare plan plus payment of two or three years' premium amounts.
Outplacement Services	Not applicable.	Not applicable.	Not applicable.	Six months.

Potential Payments

This section describes and estimates payments that would become payable to the named executive officers upon a termination or change in control as of December 31, 2012.

Pension Benefits

The amounts that would have become payable to the named executive officers if the Traditional Termination Events occurred as of December 31, 2012 under the Pension Plan, the SBP-P, the SERP, and, if applicable, an SRA are itemized in the chart below. The amounts shown under the column Retirement are amounts that would have become payable to the named executive officers that were retirement-eligible on December 31, 2012 and are the monthly Pension Plan benefits and the first of 10 annual installments from the SBP-P and the SERP. The amounts shown under the column Resignation or Involuntary Termination are the amounts that would have become payable to the named executive officers who were not retirement-eligible on December 31, 2012 and are the monthly Pension Plan benefits that would become payable as of the earliest possible date under the Pension Plan and the single sum value of benefits earned up to the termination date under the SBP-P, paid as a single payment rather than in 10 annual installments. Benefits under the SERP would be forfeited. The amounts shown that are payable to a spouse in the event of the death of the named executive officer are the monthly amounts payable to a spouse under the Pension Plan and the first of 10 annual installments from the SBP-P and the SERP. The amounts in this chart are very different from the pension values shown in the Summary Compensation Table and the Pension Benefits table. Those tables show the present values of all the benefits amounts anticipated to be paid over the lifetimes of the named executive officers and their spouses. Those plans are described in the notes following the Pension Benefits table. Of the named executive officers, Ms. Terry and Messrs. Connally, Crosswhite, and Teel were not retirement-eligible on December 31, 2012. The SRA for Ms. Terry contains an additional service requirement for benefit eligibility which was not met as of December 31, 2012. Therefore she was not eligible to receive retirement benefits under the agreement. However, death benefits would be paid to her surviving spouse.

Name		Retirement ($)	Resignation or Involuntary Termination ($)	Death (payments to a spouse) ($)
S. W. Connally, Jr.	Pension	n/a	1,766	2,900
	SBP-P	n/a	192,119	24,102
	SERP	n/a	—	40,268
M. A. Crosswhite	Pension	n/a	2,653	1,194
	SBP-P	n/a	308,771	31,227
	SERP	n/a	—	24,111
	SRA	n/a	1,146,097	163,246
R. S. Teel	Pension	n/a	1,047	1,720
	SBP-P	n/a	41,679	5,297
	SERP	n/a	—	12,415
M. L. Burroughs	Pension	2,655	All plans treated as retiring	2,221
	SBP-P	5,138		5,138
	SERP	18,717		18,717
P. B. Jacob	Pension	7,304	All plans treated as retiring	4,291
	SBP-P	30,467		30,467
	SERP	35,101		35,101
B. C. Terry	Pension	n/a	967	1,588
	SBP-P	n/a	46,355	5,926
	SERP	n/a	—	10,827
	SRA	n/a	—	54,644

As described in the Change-in-Control chart, the only change in the form of payment, acceleration, or enhancement of the pension benefits is that the single sum value of benefits earned up to the change-in-control date under the SBP-P and the SERP could be paid as a single payment rather than in 10 annual installments. Also, the SERP benefits vest for participants who are not retirement-eligible upon a change in control. Estimates of the single sum payment that would have been made to the named executive officers, assuming termination as of December 31, 2012 following a change-in-control event, other than a Southern Company Change-in-Control I (which does not impact how pension benefits are paid), are itemized below. These amounts would be paid instead of the benefits shown in the Traditional Termination Events chart above; they are not paid in addition to those amounts.

Name	SBP-P ($)	SERP ($)	SRA ($)	Total ($)
S. W. Connally, Jr.	188,642	315,169	—	503,811
M. A. Crosswhite	303,183	233,722	1,582,443	2,119,348
R. S. Teel	40,925	95,910	—	136,835
M. L. Burroughs	51,378	187,169	—	238,547
P. B. Jacob	304,668	351,007	—	655,675
B. C. Terry	45,516	83,165	419,734	548,415

The pension benefit amounts in the tables above were calculated as of December 31, 2012 assuming payments would begin as soon as possible under the terms of the plans. Accordingly, appropriate early retirement reductions were applied. Any unpaid annual performance-based compensation was assumed to be paid at 1.30 times the target level. Pension Plan benefits were

calculated assuming each named executive officer chose a single life annuity form of payment, because that results in the greatest monthly benefit. The single sum values were based on a 3.18% discount rate.

Annual Performance Pay Program
The amount payable if a change in control had occurred on December 31, 2012 is the greater of target or actual performance. Because actual payouts for 2012 performance were above the target level, the amount that would have been payable was the actual amount paid as reported in the Summary Compensation Table.

Performance Dividends
Because the assumed termination date is December 31, 2012, there is no additional amount that would be payable other than what was reported in the Summary Compensation Table. As described in the Traditional Termination Events chart, there is some continuation of benefits under the Performance Dividend Program for retirees. Under Change-in-Control-Related Events, performance dividends are payable at the greater of target performance or actual performance. For the 2009-2012 performance-measurement period, actual performance was less than target-level performance. The chart below shows the additional amounts that would have been paid upon a change in control.

Name	Additional Performance Dividends ($)
S. W. Connally, Jr.	9,741
M. A. Crosswhite	30,225
R. S. Teel	12,086
M. L. Burroughs	1,312
P. B. Jacob	10,787
B. C. Terry	15,332

Stock Options and Performance Share Units (Equity Awards)
Equity Awards would be treated as described in the Termination and Change-in-Control charts above. Under a Southern Company Termination, all Equity Awards vest. In addition, if there is an Involuntary Change-in-Control Termination or Voluntary Change-in-Control Termination for Good Reason, Equity Awards vest. There is no payment associated with Equity Awards unless there is a Southern Company Termination and the participants' Equity Awards cannot be converted into surviving company awards. In that event, the value of outstanding Equity Awards would be paid to the named executive officers. For stock options, that value is the excess of the exercise price and the closing price of Common Stock on December 31, 2012 and, for performance shares, it is the closing price on December 31, 2012. The chart below shows the number of stock options for which vesting would be accelerated under a Southern Company Termination and the amount that would be payable under a Southern Company Termination if there were no conversion to the surviving company's stock options. It also shows the number and value of performance shares that would be paid.

	Number of Equity Awards with Accelerated Vesting (#)		Total Number of Equity Awards Following Accelerated Vesting (#)		Total Payable in Cash without Conversion of Equity
Name	Stock Options	Performance Shares	Stock Options	Performance Shares	Awards ($)
S. W. Connally, Jr.	31,207	4,126	76,861	4,126	690,513
M. A. Crosswhite	118,593	16,307	256,530	16,307	2,239,720
R. S. Teel	32,818	4,322	84,825	4,322	749,070
M. L. Burroughs	16,106	2,294	23,595	2,294	186,802
P. B. Jacob	38,898	4,685	83,188	4,685	736,487
B. C. Terry	32,818	4,716	97,862	4,716	866,328

DCP and SBP

The aggregate balances reported in the Nonqualified Deferred Compensation table would be payable to the named executive officers as described in the Traditional Termination and Change-in-Control-Related Events charts above. There is no enhancement or acceleration of payments under these plans associated with termination or change-in-control events, other than the lump-sum payment opportunity described in the above charts. The lump sums that would be payable are those that are reported in the Nonqualified Deferred Compensation table.

Healthcare Benefits

Messrs. Burroughs and Jacob are retirement-eligible. Healthcare benefits are provided to retirees and there is no incremental payment associated with the termination or change-in-control events. At the end of 2012, the other named executive officers were not retirement-eligible and thus healthcare benefits would not become available until each reaches age 50, except in the case of a change-in-control-related termination, as described in the Change-in-Control-Related Events chart. The estimated cost of providing healthcare insurance premiums is less than $20,000 per year for up to a maximum of two years for Ms. Terry and Mr. Teel and up to a maximum of three years for Messrs. Connally and Crosswhite.

Financial Planning Perquisite

Since Messrs. Burroughs and Jacob are retirement-eligible, an additional year of the Financial Planning perquisite, which is set at a maximum of $8,700 per year, will be provided after retirement. The other named executive officers are not retirement-eligible.

There are no other perquisites provided to the named executive officers under any of the traditional termination or change-in-control-related events.

Severance Benefits

The named executive officers are participants in a change-in-control severance plan. The plan provides severance benefits, including outplacement services, if within two years of a change in control, they are involuntarily terminated, not for Cause, or they voluntarily terminate for Good Reason. The severance benefits are not paid unless the named executive officer releases the employing company from any claims he or she may have against the employing company.

The estimated cost of providing the six months of outplacement services is $6,000 per named executive officer. The severance payment is two times the base salary and target payout under the annual Performance Pay Program for Messrs. Connally and Crosswhite and one times the base salary and target payout under the annual Performance Pay Program for the other named executive officers.

The table below estimates the severance payments that would be made to the named executive officers if they were terminated as of December 31, 2012 in connection with a change in control.

Name	Severance Amount ($)
S. W. Connally, Jr.	1,156,000
M. A. Crosswhite	1,661,750
R. S. Teel	346,669
M. L. Burroughs	264,879
P. B. Jacob	369,579
B. C. Terry	372,016

DIRECTOR COMPENSATION

Only non-employee directors of Gulf Power are compensated for service on the board of directors.

During 2012, the pay components for non-employee directors were:

Annual cash retainer:	$22,000 per year
Annual stock retainer:	$19,500 per year in Common Stock
Board meeting fees:	If more than five meetings are held in a calendar year, $1,200 will be paid for participation beginning with the sixth meeting.
Committee meeting fees:	If more than five meetings of any one committee are held in a calendar year, $1,000 will be paid for participation in each meeting of that committee beginning with the sixth meeting.

DIRECTOR DEFERRED COMPENSATION PLAN

Any deferred quarterly equity grants or stock retainers are required to be deferred in the Deferred Compensation Plan For Directors of Gulf Power Company (Director Deferred Compensation Plan) and are invested in Common Stock units which earn dividends as if invested in Common Stock. Earnings are reinvested in additional stock units. Upon leaving the board, distributions are made in shares of Common Stock.

In addition, directors may elect to defer up to 100% of their remaining compensation in the Director Deferred Compensation Plan until membership on the board ends. Deferred compensation may be invested as follows, at the director's election:

- in Common Stock units which earn dividends as if invested in Common Stock and are distributed in shares of Common Stock upon leaving the board;
- in Common Stock units which earn dividends as if invested in Common Stock and are distributed in cash upon leaving the board; or
- at prime interest which is paid in cash upon leaving the board.

All investments and earnings in the Director Deferred Compensation Plan are fully vested and, at the election of the director, may be distributed in a lump sum payment or in up to 10 annual distributions after leaving the board.

DIRECTOR COMPENSATION TABLE

The following table reports all compensation to Gulf Power's non-employee directors during 2012, including amounts deferred in the Director Deferred Compensation Plan. Non-employee directors do not receive Non-Equity Incentive Plan Compensation, and there is no pension plan for non-employee directors.

Name	Fees Earned or Paid in Cash ($)(1)	Stock Awards ($)(2)	Change in Pension Value and Nonqualified Deferred Compensation Earnings ($)(3)	All Other Compensation ($)	Total ($)
Allan G. Bense	23,200	19,500	0	49	42,749
Deborah H. Calder	23,200	19,500	0	49	42,749
William C. Cramer, Jr.	23,200	19,500	0	498	43,198
J. Mort O'Sullivan III	23,200	19,500	0	498	43,198
William A. Pullum (4)	11,000	9,750	0	1,112	21,862
Winston E. Scott	23,200	19,500	0	49	42,749

(1) Includes amounts voluntarily deferred in the Director Deferred Compensation Plan.

(2) Includes fair market value of equity grants on grant dates. All such stock awards are vested immediately upon grant.

(3) Above-market earnings on amounts invested in the Director Deferred Compensation Plan. Above-market earnings are defined by the SEC as any amount above 120% of the applicable federal long-term rate as prescribed under Section 1274(d) of the Code.

(4) Mr. Pullum retired from Gulf Power's board of directors effective May 14, 2012.

COMPENSATION COMMITTEE INTERLOCKS AND INSIDER PARTICIPATION

The Compensation Committee is made up of non-employee directors of Southern Company who have never served as executive officers of Southern Company or Gulf Power. During 2012, none of Southern Company's or Gulf Power's executive officers served on the board of directors of any entities whose directors or officers serve on the Compensation Committee.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

(a) Security Ownership (Applicable to Gulf Power only).

Security Ownership of Certain Beneficial Owners. Southern Company is the beneficial owner of 100% of the outstanding common stock of Gulf Power.

Title of Class	Name and Address of Beneficial Owner	Amount and Nature of Beneficial Ownership	Percent of Class
Common Stock	The Southern Company 30 Ivan Allen Jr. Boulevard, N.W. Atlanta, Georgia 30308		100%
	Registrant: Gulf Power	4,542,717	

Security Ownership of Management. The following tables show the number of shares of Common Stock owned by the directors, nominees, and executive officers as of December 31, 2012. It is based on information furnished by the directors, nominees, and executive officers. The shares owned by all directors, nominees, and executive officers as a group constitute less than one percent of the total number of shares outstanding on December 31, 2012.

Name of Directors, Nominees, and Executive Officers	Shares Beneficially Owned (1)	Shares Beneficially Owned Include: Deferred Stock Units (2)	Shares Beneficially Owned Include: Shares Individuals Have Rights to Acquire Within 60 Days (3)
S. W. Connally, Jr.	67,040	0	62,129
Allan G. Bense	1,427	0	0
Deborah H. Calder	1,422	963	0
William C. Cramer, Jr.	14,033	14,033	0
J. Mort O'Sullivan III	2,024	2,024	0
Winston E. Scott	6,154	0	0
P. Bernard Jacob	75,247	0	67,686
Michael L. Burroughs	18,468	0	15,022
Richard S. Teel	69,959	0	69,375
Bentina C. Terry	86,562	0	82,216
Directors, Nominees, and Executive Officers as a group (10 people)	342,336	17,020	296,428

(1) "Beneficial ownership" means the sole or shared power to vote, or to direct the voting of, a security and/or investment power with respect to a security or any combination thereof.

(2) Indicates the number of deferred stock units held under the Director Deferred Compensation Plan.

(3) Indicates shares of Common Stock that certain executive officers have the right to acquire within 60 days. Shares indicated are included in the Shares Beneficially Owned column.

Changes in Control. Southern Company and Gulf Power know of no arrangements which may at a subsequent date result in any change-in-control.

(b) Equity Compensation Plan Information (Applicable to all registrants).

The following table provides information as of December 31, 2012 concerning shares of Common Stock authorized for issuance under Southern Company's existing non-qualified equity compensation plans.

Plan category	Number of securities to be issued upon exercise of outstanding options, warrants, and rights (a)	Weighted-average exercise price of outstanding options, warrants, and rights (b)	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)) (c)
Equity compensation plans approved by security holders	35,916,303	$36.37	39,813,434 (1)
Equity compensation plans not approved by security holders	n/a	n/a	n/a

(1) Includes shares available for future issuance under the Omnibus Incentive Compensation Plan (38,603,602) and the Outside Directors Stock Plan (1,209,832).

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE.

Transactions with Related Persons. None.

Review, Approval or Ratification of Transactions with Related Persons.

Gulf Power does not have a written policy pertaining solely to the approval or ratification of "related party transactions." Southern Company has a Code of Ethics as well as a Contract Guidance Manual and other formal written procurement policies and procedures that guide the purchase of goods and services, including requiring competitive bids for most transactions above $10,000 or approval based on documented business needs for sole sourcing arrangements. The approval and ratification of any related party transactions would be subject to these written policies and procedures which include a determination of the need for the goods and services; preparation and evaluation of requests for proposals by supply chain management; the writing of contracts; controls and guidance regarding the evaluation of the proposals; and negotiation of contract terms and conditions. As appropriate, these contracts are also reviewed by individuals in the legal, accounting, and/or risk management/ services departments prior to being approved by the responsible individual. The responsible individual will vary depending on the department requiring the goods and services, the dollar amount of the contract, and the appropriate individual within that department who has the authority to approve a contract of the applicable dollar amount.

Director Independence.

The board of directors of Gulf Power consists of five non-employee directors (Ms. Deborah H. Calder and Messrs. Allan G. Bense, William C. Cramer, Jr., J. Mort O'Sullivan, III, and Winston E. Scott) and Mr. Connally. Mr. William A. Pullum retired from the board of directors effective May 14, 2012.

Southern Company owns all of Gulf Power's outstanding common stock. Gulf Power has listed only debt securities on the NYSE. Accordingly, under the rules of the NYSE, Gulf Power is exempt from most of the NYSE's listing standards relating to corporate governance, including requirements relating to certain board committees. Gulf Power has voluntarily complied with certain NYSE listing standards relating to corporate governance where such compliance was deemed to be in the best interests of Gulf Power's shareholders.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The following represents the fees billed to Gulf Power and Southern Power for the last two fiscal years by Deloitte & Touche LLP, each company's principal public accountant for 2012 and 2011:

	2012	2011
	(in thousands)	
Gulf Power		
Audit Fees (1)	$ 1,454	$ 1,326
Audit-Related Fees (2)	—	118
Tax Fees	—	—
All Other Fees	—	—
Total	$ 1,454	$ 1,444
Southern Power		
Audit Fees (1)	$ 1,279	$ 1,270
Audit-Related Fees	—	—
Tax Fees	—	—
All Other Fees	—	—
Total	$ 1,279	$ 1,270

(1) Includes services performed in connection with financing transactions.
(2) Includes other non-statutory audit services and accounting consultations.

The Southern Company Audit Committee (on behalf of Southern Company and its subsidiaries) adopted a Policy of Engagement of the Independent Auditor for Audit and Non-Audit Services that includes requirements for such Audit Committee to pre-approve audit and non-audit services provided by Deloitte & Touche LLP. All of the audit services provided by Deloitte & Touche LLP in fiscal years 2012 and 2011 (described in the footnotes to the table above) and related fees were approved in advance by the Southern Company Audit Committee.

PART IV

Item 15. **EXHIBITS AND FINANCIAL STATEMENT SCHEDULES**

(a) The following documents are filed as a part of this report on Form 10-K:

(1) Financial Statements and Financial Statement Schedules:

Management's Report on Internal Control Over Financial Reporting for Southern Company and Subsidiary Companies is listed under Item 8 herein.

Management's Report on Internal Control Over Financial Reporting for Alabama Power is listed under Item 8 herein.

Management's Report on Internal Control Over Financial Reporting for Georgia Power is listed under Item 8 herein.

Management's Report on Internal Control Over Financial Reporting for Gulf Power is listed under Item 8 herein.

Management's Report on Internal Control Over Financial Reporting for Mississippi Power is listed under Item 8 herein.

Management's Report on Internal Control Over Financial Reporting for Southern Power and Subsidiary Companies is listed under Item 8 herein.

Reports of Independent Registered Public Accounting Firm on the financial statements and financial statement schedules for Southern Company and Subsidiary Companies, Alabama Power, Georgia Power, Gulf Power and Mississippi Power, as well as the Report of Independent Registered Public Accounting Firm on the financial statements of Southern Power and Subsidiary Companies are listed under Item 8 herein.

The financial statements filed as a part of this report for Southern Company and Subsidiary Companies, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, and Southern Power and Subsidiary Companies are listed under Item 8 herein.

The financial statement schedules for Southern Company and Subsidiary Companies, Alabama Power, Georgia Power, Gulf Power, and Mississippi Power are listed in the Index to the Financial Statement Schedules at page S-1.

(2) Exhibits:

Exhibits for Southern Company, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, and Southern Power are listed in the Exhibit Index at page E-1.

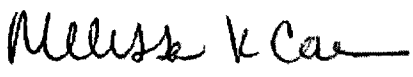
THE SOUTHERN COMPANY

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

THE SOUTHERN COMPANY

By: Thomas A. Fanning
Chairman, President, and
Chief Executive Officer

By: 
(Melissa K. Caen, Attorney-in-fact)

Date: February 27, 2013

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signature of each of the undersigned shall be deemed to relate only to matters having reference to the above-named company and any subsidiaries thereof.

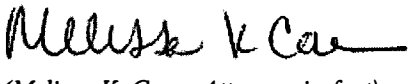
Thomas A. Fanning
Chairman, President,
Chief Executive Officer, and Director
(Principal Executive Officer)

Art P. Beattie
Executive Vice President and Chief Financial Officer
(Principal Financial Officer)

W. Ron Hinson
Comptroller and Chief Accounting Officer
(Principal Accounting Officer)

Directors:

Juanita Powell Baranco
Jon A. Boscia
Henry A. Clark III
David J. Grain
H. William Habermeyer, Jr.
Veronica M. Hagen
Warren A. Hood, Jr.
Donald M. James
Dale E. Klein
William G. Smith, Jr.
Steven R. Specker
E. Jenner Wood III

By: 
(Melissa K. Caen, Attorney-in-fact)

Date: February 27, 2013

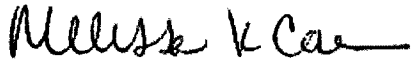
ALABAMA POWER COMPANY

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

ALABAMA POWER COMPANY

By: Charles D. McCrary
President and Chief Executive Officer

By: 
(Melissa K. Caen, Attorney-in-fact)

Date: February 27, 2013

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signature of each of the undersigned shall be deemed to relate only to matters having reference to the above-named company and any subsidiaries thereof.

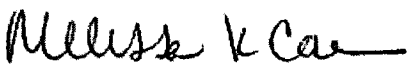
Charles D. McCrary
President, Chief Executive Officer, and Director
(Principal Executive Officer)

Philip C. Raymond
Executive Vice President, Chief Financial Officer, and Treasurer
(Principal Financial Officer)

Anita Allcorn-Walker
Vice President and Comptroller
(Principal Accounting Officer)

Directors:

Whit Armstrong
Ralph D. Cook
David J. Cooper, Sr.
Thomas A. Fanning
John D. Johns
Patricia M. King
James K. Lowder
Malcolm Portera
Robert D. Powers
C. Dowd Ritter
James H. Sanford
John Cox Webb, IV

By: 
(Melissa K. Caen, Attorney-in-fact)

Date: February 27, 2013

GEORGIA POWER COMPANY

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

GEORGIA POWER COMPANY

By: W. Paul Bowers
President and Chief Executive Officer

By:
(Melissa K. Caen, Attorney-in-fact)

Date: February 27, 2013

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signature of each of the undersigned shall be deemed to relate only to matters having reference to the above-named company and any subsidiaries thereof.

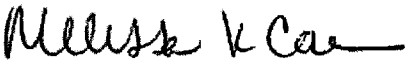
W. Paul Bowers
President, Chief Executive Officer, and Director
(Principal Executive Officer)

Ronnie R. Labrato
Executive Vice President, Chief Financial Officer, and Treasurer
(Principal Financial Officer)

Ann P. Daiss
Vice President, Comptroller, and Chief Accounting Officer
(Principal Accounting Officer)

Directors:

Robert L. Brown, Jr.
Anna R. Cablik
Thomas A. Fanning
Stephen S. Green
Jimmy C. Tallent
Charles K. Tarbutton
Beverly Daniel Tatum
D. Gary Thompson
Clyde C. Tuggle
Richard W. Ussery

By: 
(Melissa K. Caen, Attorney-in-fact)

Date: February 27, 2013

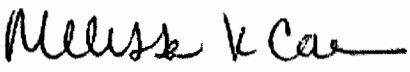
GULF POWER COMPANY

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

GULF POWER COMPANY

By: S. W. Connally, Jr.
President and Chief Executive Officer

By: 
(Melissa K. Caen, Attorney-in-fact)

Date: February 27, 2013

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signature of each of the undersigned shall be deemed to relate only to matters having reference to the above-named company and any subsidiaries thereof.

S. W. Connally, Jr.
President, Chief Executive Officer, and Director
(Principal Executive Officer)

Richard S. Teel
Vice President and Chief Financial Officer
(Principal Financial Officer)

Constance J. Erickson
Comptroller
(Principal Accounting Officer)

Directors:

Allan G. Bense
Deborah H. Calder
William C. Cramer, Jr.
J. Mort O'Sullivan, III
Winston E. Scott

By:
(Melissa K. Caen, Attorney-in-fact)

Date: February 27, 2013

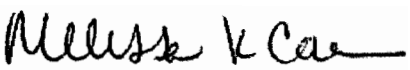
MISSISSIPPI POWER COMPANY

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

MISSISSIPPI POWER COMPANY

By: Edward Day, VI
President and Chief Executive Officer

By: 
(Melissa K. Caen, Attorney-in-fact)

Date: February 27, 2013

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signature of each of the undersigned shall be deemed to relate only to matters having reference to the above-named company and any subsidiaries thereof.

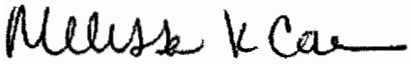
Edward Day, VI
President, Chief Executive Officer, and Director
(Principal Executive Officer)

Moses H. Feagin
Vice President, Treasurer, and
Chief Financial Officer
(Principal Financial Officer)

Cynthia F. Shaw
Comptroller
(Principal Accounting Officer)

Directors:

Carl J. Chaney
L. Royce Cumbest
Christine L. Pickering
Phillip J. Terrell
M. L. Waters

By: 
(Melissa K. Caen, Attorney-in-fact)

Date: February 27, 2013

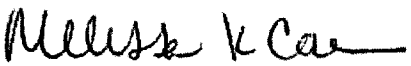
SOUTHERN POWER COMPANY

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

SOUTHERN POWER COMPANY

By: Oscar C. Harper IV
President and Chief Executive Officer

By: 
(Melissa K. Caen, Attorney-in-fact)

Date: February 27, 2013

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signature of each of the undersigned shall be deemed to relate only to matters having reference to the above-named company and any subsidiaries thereof.

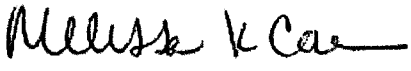
Oscar C. Harper IV
President, Chief Executive Officer, and Director
(Principal Executive Officer)

Michael W. Southern
Senior Vice President and Chief Financial Officer
(Principal Financial Officer)

Janet J. Hodnett
Comptroller and Corporate Secretary
(Principal Accounting Officer)

Directors:

Art P. Beattie
Mark A. Crosswhite
Thomas A. Fanning
G. Edison Holland, Jr.
Christopher C. Womack

By: 
(Melissa K. Caen, Attorney-in-fact)

Date: February 27, 2013

Supplemental Information to be Furnished With Reports Filed Pursuant to Section 15(d) of the Act by Registrants Which Have Not Registered Securities Pursuant to Section 12 of the Act:

No annual report, proxy statement, form of proxy or other proxy soliciting material has been sent to security holders of the registrant during the period covered by this Annual Report on Form 10-K for the fiscal year ended December 31, 2012.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
Southern Company

We have audited the consolidated financial statements of Southern Company and Subsidiaries (the "Company") as of December 31, 2012 and 2011, and for each of the three years in the period ended December 31, 2012, and the Company's internal control over financial reporting as of December 31, 2012, and have issued our report thereon dated February 27, 2013; such report is included elsewhere in this Form 10-K. Our audits also included the consolidated financial statement schedule of the Company (page S-2) listed in Item 15. This consolidated financial statement schedule is the responsibility of the Company's management. Our responsibility is to express an opinion based on our audits. In our opinion, such consolidated financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

Deloitte & Touche LLP

Atlanta, Georgia
February 27, 2013

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of
Alabama Power Company

We have audited the financial statements of Alabama Power Company (the "Company") as of December 31, 2012 and 2011, and for each of the three years in the period ended December 31, 2012, and have issued our report thereon dated February 27, 2013; such report is included elsewhere in this Form 10-K. Our audits also included the financial statement schedule of the Company (Page S-3) listed in Item 15. This financial statement schedule is the responsibility of the Company's management. Our responsibility is to express an opinion based on our audits. In our opinion, such financial statement schedule, when considered in relation to the basic financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

Deloitte & Touche LLP

Birmingham, Alabama
February 27, 2013

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of
Georgia Power Company

We have audited the financial statements of Georgia Power Company (the "Company") as of December 31, 2012 and 2011, and for each of the three years in the period ended December 31, 2012, and have issued our report thereon dated February 27, 2013; such report is included elsewhere in this Form 10-K. Our audits also included the financial statement schedule of the Company (Page S-4) listed in Item 15. This financial statement schedule is the responsibility of the Company's management. Our responsibility is to express an opinion based on our audits. In our opinion, such financial statement schedule, when considered in relation to the basic financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

Deloitte & Touche LLP

Atlanta, Georgia
February 27, 2013

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of
Gulf Power Company

We have audited the financial statements of Gulf Power Company (the "Company") as of December 31, 2012 and 2011, and for each of the three years in the period ended December 31, 2012, and have issued our report thereon dated February 27, 2013; such report is included elsewhere in this Form 10-K. Our audits also included the financial statement schedule of the Company (Page S-5) listed in Item 15. This financial statement schedule is the responsibility of the Company's management. Our responsibility is to express an opinion based on our audits. In our opinion, such financial statement schedule, when considered in relation to the basic financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

Deloitte & Touche LLP

Atlanta, Georgia
February 27, 2013

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of
Mississippi Power Company

We have audited the financial statements of Mississippi Power Company (the "Company") as of December 31, 2012 and 2011, and for each of the three years in the period ended December 31, 2012, and have issued our report thereon dated February 27, 2013; such report is included elsewhere in this Form 10-K. Our audits also included the financial statement schedule of the Company (Page S-6) listed in Item 15. This financial statement schedule is the responsibility of the Company's management. Our responsibility is to express an opinion based on our audits. In our opinion, such financial statement schedule, when considered in relation to the basic financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

Deloitte & Touche LLP

Atlanta, Georgia
February 27, 2013

INDEX TO FINANCIAL STATEMENT SCHEDULES

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The Southern Company and Subsidiary Companies	S-2
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Georgia Power Company	S-4
Gulf Power Company	S-5
Mississippi Power Company	S-6

Schedules I through V not listed above are omitted as not applicable or not required. A Schedule II for Southern Power Company and Subsidiary Companies is not being provided because there were no reportable items for the three-year period ended December 31, 2012. Columns omitted from schedules filed have been omitted because the information is not applicable or not required.

THE SOUTHERN COMPANY AND SUBSIDIARY COMPANIES
SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS
FOR THE YEARS ENDED DECEMBER 31, 2012, 2011, AND 2010
(Stated in Thousands of Dollars)

Description	Balance at Beginning of Period	Additions: Charged to Income	Additions: Charged to Other Accounts	Deductions (Note)	Balance at End of Period
Provision for uncollectible accounts					
2012	$ 26,155	$ 35,305	$ —	$ 44,476	$ 16,984
2011	24,919	66,641	—	65,405	26,155
2010	24,568	62,137	—	61,786	24,919

(Note) Represents write-off of accounts considered to be uncollectible, less recoveries of amounts previously written off.

ALABAMA POWER COMPANY
SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS
FOR THE YEARS ENDED DECEMBER 31, 2012, 2011, AND 2010
(Stated in Thousands of Dollars)

Description	Balance at Beginning of Period	Additions: Charged to Income	Additions: Charged to Other Accounts	Deductions (Note)	Balance at End of Period
Provision for uncollectible accounts					
2012	$ 9,856	$ 10,537	$ —	$ 11,943	$ 8,450
2011	9,602	16,415	—	16,161	9,856
2010	9,551	18,271	—	18,220	9,602

(Note) *Represents write-off of accounts considered to be uncollectible, less recoveries of amounts previously written off.*

GEORGIA POWER COMPANY
SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS
FOR THE YEARS ENDED DECEMBER 31, 2012, 2011, AND 2010
(Stated in Thousands of Dollars)

Description	Balance at Beginning of Period	Additions: Charged to Income	Additions: Charged to Other Accounts	Deductions (Note)	Balance at End of Period
Provision for uncollectible accounts					
2012	$ 13,038	$ 20,995	$ —	$ 27,774	$ 6,259
2011	11,098	45,267	—	43,327	13,038
2010	9,856	37,004	—	35,762	11,098

(Note) *Represents write-off of accounts considered to be uncollectible, less recoveries of amounts previously written off.*

GULF POWER COMPANY
SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS
FOR THE YEARS ENDED DECEMBER 31, 2012, 2011, AND 2010
(Stated in Thousands of Dollars)

Description	Balance at Beginning of Period	Additions: Charged to Income	Additions: Charged to Other Accounts	Deductions (Note)	Balance at End of Period
Provision for uncollectible accounts					
2012	$ 1,962	$ 2,611	$ —	$ 3,083	$ 1,490
2011	2,014	3,332	—	3,384	1,962
2010	1,913	3,907	—	3,806	2,014

(Note) *Represents write-off of accounts considered to be uncollectible, less recoveries of amounts previously written off.*

MISSISSIPPI POWER COMPANY
SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS
FOR THE YEARS ENDED DECEMBER 31, 2012, 2011, AND 2010
(Stated in Thousands of Dollars)

Description	Balance at Beginning of Period	Additions		Deductions (Note)	Balance at End of Period
		Charged to Income	Charged to Other Accounts		
Provision for uncollectible accounts					
2012	$ 547	$ 628	$ —	$ 802	$ 373
2011	638	1,235	—	1,326	547
2010	940	1,519	—	1,821	638

(Note) *Represents write-off of accounts considered to be uncollectible, less recoveries of amounts previously written off.*

EXHIBIT INDEX

The exhibits below with an asterisk (*) preceding the exhibit number are filed herewith. The remaining exhibits have previously been filed with the SEC and are incorporated herein by reference. The exhibits marked with a pound sign (#) are management contracts or compensatory plans or arrangements required to be identified as such by Item 15 of Form 10-K.

(2) Plan of acquisition, reorganization, arrangement, liquidation or succession

Mississippi Power

(e) 1 — Assignment and Assumption Agreement dated as of October 20, 2011, between Mississippi Power and Juniper Capital L.P. (Designated in Form 8-K dated October 20, 2011, File No. 001-11229, as Exhibit 2.1.)

(e) 2 — Bond Assumption and Exchange Agreement, dated as of October 20, 2011, by and among Mississippi Business Finance Corporation, Mississippi Power, and the bondholders parties thereto. (Designated in Form 8-K dated October 20, 2011, File No. 001-11229, as Exhibit 2.2.)

(3) Articles of Incorporation and By-Laws

Southern Company

(a) 1 — Composite Certificate of Incorporation of Southern Company, reflecting all amendments thereto through May 27, 2010. (Designated in Registration No. 33-3546 as Exhibit 4(a), in Certificate of Notification, File No. 70-7341, as Exhibit A, in Certificate of Notification, File No. 70-8181, as Exhibit A, and in Form 8-K dated May 26, 2010, File No. 1-3526, as Exhibit 3.1.)

(a) 2 — By-laws of Southern Company as amended effective February 11, 2013, and as presently in effect. (Designated in Form 8-K dated February 11, 2013, File No. 1-3526, as Exhibit 3.1.)

Alabama Power

(b) 1 — Charter of Alabama Power and amendments thereto through April 25, 2008. (Designated in Registration Nos. 2-59634 as Exhibit 2(b), 2-60209 as Exhibit 2(c), 2-60484 as Exhibit 2(b), 2-70838 as Exhibit 4(a)-2, 2-85987 as Exhibit 4(a)-2, 33-25539 as Exhibit 4(a)-2, 33-43917 as Exhibit 4(a)-2, in Form 8-K dated February 5, 1992, File No. 1-3164, as Exhibit 4(b)-3, in Form 8-K dated July 8, 1992, File No. 1-3164, as Exhibit 4(b)-3, in Form 8-K dated October 27, 1993, File No. 1-3164, as Exhibits 4(a) and 4(b), in Form 8-K dated November 16, 1993, File No. 1-3164, as Exhibit 4(a), in Certificate of Notification, File No. 70-8191, as Exhibit A, in Alabama Power's Form 10-K for the year ended December 31, 1997, File No. 1-3164, as Exhibit 3(b)2, in Form 8-K dated August 10, 1998, File No. 1-3164, as Exhibit 4.4, in Alabama Power's Form 10-K for the year ended December 31, 2000, File No. 1-3164, as Exhibit 3(b)2, in Alabama Power's Form 10-K for the year ended December 31, 2001, File No. 1-3164, as Exhibit 3(b)2, in Form 8-K dated February 5, 2003, File No. 1-3164, as Exhibit 4.4, in Alabama Power's Form 10-Q for the quarter ended March 31, 2003, File No 1-3164, as Exhibit 3(b)1, in Form 8-K dated February 5, 2004, File No. 1-3164, as Exhibit 4.4, in Alabama Power's Form 10-Q for the quarter ended March 31, 2006, File No. 1-3164, as Exhibit 3(b)(1), in Form 8-K dated December 5, 2006, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated September 12, 2007, File No. 1-3164, as Exhibit 4.5, in Form 8-K dated October 17, 2007, File No. 1-3164, as Exhibit 4.5, and in Alabama Power's Form 10-Q for the quarter ended March 31, 2008, File No. 1-3164, as Exhibit 3(b)1.)

(b) 2 — By-laws of Alabama Power as amended effective April 22, 2011, and as presently in effect. (Designated in Form 8-K dated April 22, 2011, File No 1-3164, as Exhibit 3.1.)

Georgia Power

(c) 1 — Charter of Georgia Power and amendments thereto through October 9, 2007. (Designated in Registration Nos. 2-63392 as Exhibit 2(a)-2, 2-78913 as Exhibits 4(a)-(2) and 4(a)-(3), 2-93039 as Exhibit 4(a)-(2), 2-96810 as Exhibit 4(a)-2, 33-141 as Exhibit 4(a)-(2), 33-1359 as Exhibit 4(a)(2), 33-5405 as Exhibit 4(b)(2), 33-14367 as Exhibits 4(b)-(2) and 4(b)-(3), 33-22504 as Exhibits 4(b)-(2), 4(b)-(3) and 4(b)-(4), in Georgia Power's Form 10-K for the year ended December 31, 1991, File No. 1-6468, as Exhibits 4(a)(2) and 4(a)(3), in Registration No. 33-48895 as Exhibits 4(b)-(2) and 4(b)-(3), in Form 8-K dated December 10, 1992, File No. 1-6468 as Exhibit 4(b), in Form 8-K dated June 17, 1993, File No. 1-6468, as Exhibit 4(b), in Form 8-K dated October 20, 1993, File No. 1-6468, as Exhibit 4(b), in Georgia Power's Form 10-K for the year ended December 31, 1997, File No. 1-6468, as Exhibit 3(c)2, in Georgia Power's Form 10-K for the year ended December 31, 2000, File No. 1-6468, as Exhibit 3(c)2, in Form 8-K dated June 27, 2006, File No. 1-6468, as Exhibit 3.1, and in Form 8-K dated October 3, 2007, File No. 1-6468, as Exhibit 4.5.)

(c) 2 — By-laws of Georgia Power as amended effective May 20, 2009, and as presently in effect. (Designated in Form 8-K dated May 20, 2009, File No. 1-6468, as Exhibit 3(c)2.)

Gulf Power

(d) 1 — Amended and Restated Articles of Incorporation of Gulf Power and amendments thereto through October 17, 2007. (Designated in Form 8-K dated October 27, 2005, File No. 0-2429, as Exhibit 3.1, in Form 8-K dated November 9, 2005, File No. 0-2429, as Exhibit 4.7, and in Form 8-K dated October 16, 2007, File No. 0-2429, as Exhibit 4.5.)

(d) 2 — By-laws of Gulf Power as amended effective November 2, 2005, and as presently in effect. (Designated in Form 8-K dated November 2, 2005, File No. 0-2429, as Exhibit 3.2.)

Mississippi Power

(e) 1 — Articles of Incorporation of Mississippi Power, articles of merger of Mississippi Power Company (a Maine corporation) into Mississippi Power and articles of amendment to the articles of incorporation of Mississippi Power through April 2, 2004. (Designated in Registration No. 2-71540 as Exhibit 4(a)-1, in Form U5S for 1987, File No. 30-222-2, as Exhibit B-10, in Registration No. 33-49320 as Exhibit 4(b)-(1), in Form 8-K dated August 5, 1992, File No. 001-11229, as Exhibits 4(b)-2 and 4(b)-3, in Form 8-K dated August 4, 1993, File No. 001-11229, as Exhibit 4(b)-3, in Form 8-K dated August 18, 1993, File No. 001-11229, as Exhibit 4(b)-3, in Mississippi Power's Form 10-K for the year ended December 31, 1997, File No. 001-11229, as Exhibit 3(e)2, in Mississippi Power's Form 10-K for the year ended December 31, 2000, File No. 001-11229, as Exhibit 3(e)2, and in Form 8-K dated March 3, 2004, File No. 001-11229, as Exhibit 4.6.)

(e) 2 — By-laws of Mississippi Power as amended effective February 28, 2001, and as presently in effect. (Designated in Mississippi Power's Form 10-K for the year ended December 31, 2001, File No. 001-11229, as Exhibit 3(e)2.)

Southern Power

(f) 1 — Certificate of Incorporation of Southern Power dated January 8, 2001. (Designated in Registration No. 333-98553 as Exhibit 3.1.)

(f) 2 — By-laws of Southern Power effective January 8, 2001. (Designated in Registration No. 333-98553 as Exhibit 3.2.)

(4) Instruments Describing Rights of Security Holders, Including Indentures

With respect to each of Southern Company, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, and Southern Power, such registrant has not included any instrument with respect to long-term debt that does not exceed 10% of the total assets of such registrant and its subsidiaries. Each such registrant agrees, upon request of the SEC, to furnish copies of any or all such instruments to the SEC.

Southern Company

(a) 1 — Senior Note Indenture dated as of January 1, 2007, between Southern Company and Wells Fargo Bank, National Association, as Trustee, and indentures supplemental thereto through August 23, 2011. (Designated in Form 8-K dated January 11, 2006, File No. 1-3526, as Exhibits 4.1 and 4.2, in Form 8-K dated March 20, 2007, File No. 1-3526, as Exhibit 4.2, in Form 8-K dated August 13, 2008, File No. 1-3526, as Exhibit 4.2, in Form 8-K dated May 11, 2009, File No. 1-3526, as Exhibit 4.2, in Form 8-K dated October 19, 2009, File No. 1-3526, as Exhibit 4.2, in Form 8-K dated September 13, 2010, File No. 1-3526, as Exhibit 4.2, and in Form 8-K dated August 16, 2011, File No. 1-3526, as Exhibit 4.2.)

Alabama Power

(b) 1 — Subordinated Note Indenture dated as of January 1, 1997, between Alabama Power and The Bank of New York Mellon (as successor to JPMorgan Chase Bank, N.A. (formerly known as The Chase Manhattan Bank)), as Trustee, and indentures supplemental thereto through October 2, 2002. (Designated in Form 8-K dated January 9, 1997, File No. 1-3164, as Exhibits 4.1 and 4.2, in Form 8-K dated February 18, 1999, File No. 1-3164, as Exhibit 4.2, and in Form 8-K dated September 26, 2002, File No. 3164, as Exhibits 4.9-A and 4.9-B.)

(b) 2 — Senior Note Indenture dated as of December 1, 1997, between Alabama Power and The Bank of New York Mellon (as successor to JPMorgan Chase Bank, N.A. (formerly known as The Chase Manhattan Bank)), as Trustee, and indentures supplemental thereto through December 5, 2012. (Designated in Form 8-K dated December 4, 1997, File No. 1-3164, as Exhibits 4.1 and 4.2, in Form 8-K dated February 20, 1998, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated April 17, 1998, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated August 11, 1998, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated September 8, 1998, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated September 16, 1998, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated October 7, 1998, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated October 28, 1998, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated November 12, 1998, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated May 19, 1999, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated August 13, 1999, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated September 21, 1999, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated May 11, 2000, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated August 22, 2001, File No. 1-3164, as Exhibits 4.2(a) and 4.2(b), in Form 8-K dated June 21, 2002, File No. 1-3164, as Exhibit 4.2(a), in Form 8-K dated October 16, 2002, File No. 1-3164, as Exhibit 4.2(a), in Form 8-K dated November 20, 2002, File No. 1-3164, as Exhibit 4.2(a), in Form 8-K dated December 6, 2002, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated February 11, 2003, File No. 1-3164, as Exhibits 4.2(a) and 4.2(b), in Form 8-K dated March 12, 2003, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated April 15, 2003, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated May 1, 2003, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated November 14, 2003, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated February 10, 2004, File No. 1-3164, as Exhibit 4.2 in Form 8-K dated April 7, 2004, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated August 19, 2004, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated November 9, 2004, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated March 8, 2005, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated January 11, 2006, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated January 13, 2006, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated February 1, 2006, File No. 1-3164, as Exhibits 4.2(a) and 4.2(b), in Form 8-K dated March 9, 2006, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated June 7, 2006, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated January 30, 2007, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated April 4, 2007, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated October 11, 2007, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated December 4, 2007, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated May 8, 2008, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated November 14, 2008, File No. 1-3164 as Exhibit 4.2, in Form 8-K dated February 26, 2009, File No. 1-3164 as Exhibit 4.2, in Form 8-K dated September 27, 2010, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated March 3, 2011, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated May 18, 2011, File No. 1-3164, as Exhibits 4.2(a) and 4.2(b), in Form 8-K dated January 10, 2012, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated October 9, 2012, File No. 1-3164, as Exhibit 4.2, and in Form 8-K dated November 27, 2012, File No. 1-3164, as Exhibit 4.2.)

(b) 3 — Amended and Restated Trust Agreement of Alabama Power Capital Trust V dated as of September 1, 2002. (Designated in Form 8-K dated September 26, 2002, File No. 1-3164, as Exhibit 4.12-B.)

(b) 4 — Guarantee Agreement relating to Alabama Power Capital Trust V dated as of September 1, 2002. (Designated in Form 8-K dated September 26, 2002, File No. 1-3164, as Exhibit 4.16-B.)

Georgia Power

(c) 1 — Senior Note Indenture dated as of January 1, 1998, between Georgia Power and The Bank of New York Mellon (as successor to JPMorgan Chase Bank, N.A. (formerly known as The Chase Manhattan Bank)), as Trustee, and indentures supplemental thereto through November 15, 2012. (Designated in Form 8-K dated January 21, 1998, File No. 1-6468, as Exhibits 4.1 and 4.2, in Forms 8-K each dated November 19, 1998, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated March 3, 1999, File No. 1-6469 as Exhibit 4.2, in Form 8-K dated February 15, 2000, File No. 1-6469 as Exhibit 4.2, in Form 8-K dated January 26, 2001, File No. 1-6469 as Exhibits 4.2(a) and 4.2(b), in Form 8-K dated February 16, 2001, File No. 1-6469 as Exhibit 4.2, in Form 8-K dated May 1, 2001, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated June 27, 2002, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated November 15, 2002, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated February 13, 2003, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated February 21, 2003, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated April 10, 2003, File No. 1-6468, as Exhibits 4.1, 4.2 and 4.3, in Form 8-K dated September 8, 2003, File No. 1-6468, as Exhibit 4.1, in Form 8-K dated September 23, 2003, File No. 1-6468, as Exhibit 4.1, in Form 8-K dated January 12, 2004, File No. 1-6468, as Exhibits 4.1 and 4.2, in Form 8-K dated February 12, 2004, File No. 1-6468, as Exhibit 4.1, in Form 8-K dated August 11, 2004, File No. 1-6468, as Exhibits 4.1 and 4.2, in Form 8-K dated January 13, 2005, File No. 1-6468, as Exhibit 4.1, in Form 8-K dated April 12, 2005, File No. 1-6468, as Exhibit 4.1, in Form 8-K dated November 30, 2005, File No. 1-6468, as Exhibit 4.1, in Form 8-K dated December 8, 2006, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated March 6, 2007, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated June 4, 2007, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated June 18, 2007, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated July 10, 2007, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated August 24, 2007, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated November 29, 2007, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated March 12, 2008, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated June 5, 2008, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated November 12, 2008, File No. 1-6468, as Exhibits 4.2(a) and 4.2(b), in Form 8-K dated February 4, 2009, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated December 8, 2009, File No. 1-6468, as Exhibit 4.2, and in Form 8-K dated March 9, 2010, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated May 24, 2010, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated August 26, 2010, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated September 20, 2010, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated January 13, 2011, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated April 12, 2011, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated February 29, 2012, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated May 8, 2012, File No. 1-6468, as Exhibit 4.2(b), in Form 8-K dated August 7, 2012, File No. 1-6468, as Exhibit 4.2, and in Form 8-K dated November 8, 2012, File No. 1-6468, as Exhibit 4.2.)

(c) 2 — Senior Note Indenture dated as of March 1, 1998 between Georgia Power, as successor to Savannah Electric, and The Bank of New York Mellon (as successor to JPMorgan Chase Bank, N.A. (formerly known as The Chase Manhattan Bank)), as Trustee, and indentures supplemental thereto through June 30, 2006. (Designated in Form 8-K dated March 9, 1998, File No. 1-5072, as Exhibits 4.1 and 4.2, in Form 8-K dated May 8, 2001, File No. 1-5072, as Exhibits 4.2(a) and 4.2(b), in Form 8-K dated March 4, 2002, File No. 1-5072, as Exhibit 4.2, in Form 8-K dated November 4, 2002, File No. 1-5072, as Exhibit 4.2, in Form 8-K dated December 10, 2003, File No. 1-5072, as Exhibits 4.1 and 4.2, in Form 8-K dated December 2, 2004, File No. 1-5072, as Exhibit 4.1, and in Form 8-K dated June 27, 2006, File No. 1-6468, as Exhibit 4.2.)

Gulf Power

(d) 1 — Senior Note Indenture dated as of January 1, 1998, between Gulf Power and The Bank of New York Mellon (as successor to JPMorgan Chase Bank, N.A. (formerly known as The Chase Manhattan Bank)), as Trustee, and indentures supplemental thereto through May 18, 2012. (Designated in Form 8-K dated June 17, 1998, File No. 0-2429, as Exhibits 4.1 and 4.2, in Form 8-K dated August 17, 1999, File No. 0-2429, as Exhibit 4.2, in Form 8-K dated July 31, 2001, File No. 0-2429, as Exhibit 4.2, in Form 8-K dated October 5, 2001, File No. 0-2429, as Exhibit 4.2, in Form 8-K dated January 18, 2002, File No. 0-2429, as Exhibit 4.2, in Form 8-K dated March 21, 2003, File No. 0-2429, as Exhibit 4.2, in Form 8-K dated July 10, 2003, File No. 001-31737, as Exhibits 4.1 and 4.2, in Form 8-K dated September 5, 2003, File No. 001-31737, as Exhibit 4.1, in Form 8-K dated April 6, 2004, File No. 001-31737, as Exhibit 4.1, in Form 8-K dated September 13, 2004, File No. 001-31737, as Exhibit 4.1, in Form 8-K dated August 11, 2005, File No. 001-31737, as Exhibit 4.1, in Form 8-K dated October 27, 2005, File No. 001-31737, as Exhibit 4.1, in Form 8-K dated November 28, 2006, File No. 001-31737, as Exhibit 4.2, in Form 8-K dated June 5, 2007, File No. 001-31737, as Exhibit 4.2, in Form 8-K dated June 22, 2009, File No. 001-31737, as Exhibit 4.2, in Form 8-K dated April 6, 2010, File No. 001-31737, as Exhibit 4.2, in Form 8-K dated September 9, 2010, File No. 001-31737, as Exhibit 4.2, in Form 8-K dated May 12, 2011, File No. 001-31737, as Exhibit 4.2, and in Form 8-K dated May 15, 2012, File No. 001-31737, as Exhibit 4.2.)

Mississippi Power

(e) 1 — Senior Note Indenture dated as of May 1, 1998 between Mississippi Power and Wells Fargo Bank, National Association, as Successor Trustee, and indentures supplemental thereto through March 9, 2012. (Designated in Form 8-K dated May 14, 1998, File No. 001-11229, as Exhibits 4.1, 4.2(a) and 4.2(b), in Form 8-K dated March 22, 2000, File No. 001-11229, as Exhibit 4.2, in Form 8-K dated March 12, 2002, File No. 001-11229, as Exhibit 4.2, in Form 8-K dated April 24, 2003, File No. 001-11229, as Exhibit 4.2, in Form 8-K dated March 3, 2004, File No. 001-11229, as Exhibit 4.2, in Form 8-K dated June 24, 2005, File No. 001-11229, as Exhibit 4.2, in Form 8-K dated November 8, 2007, File No. 001-11229, as Exhibit 4.2, in Form 8-K dated November 14, 2008, File No. 001-11229, as Exhibit 4.2, in Form 8-K dated March 3, 2009, File No. 001-11229, as Exhibit 4.2, in Form 8-K dated October 11, 2011, File No. 001-11229, as Exhibits 4.2(a) and 4.2(b), and in Form 8-K dated March 5, 2012, File No. 001-11229, as Exhibit 4.2(b).)

Southern Power

(f) 1 — Senior Note Indenture dated as of June 1, 2002, between Southern Power and The Bank of New York Mellon (formerly known as The Bank of New York), as Trustee, and indentures supplemental thereto through September 22, 2011. (Designated in Registration No. 333-98553 as Exhibits 4.1 and 4.2 and in Southern Power's Form 10-Q for the quarter ended June 30, 2003, File No. 333-98553, as Exhibit 4(g)1, in Form 8-K dated November 13, 2006, File No. 333-98553, as Exhibit 4.2, and in Form 8-K dated September 14, 2011, File No. 333-98553, as Exhibit 4.4.)

(10) Material Contracts

Southern Company

\# (a) 1 — Southern Company 2011 Omnibus Incentive Compensation Plan, effective May 25, 2011. (Designated in Southern Company's Form 8-K dated May 25, 2011, File No. 1-3526, as Exhibit 10.1.)

\# (a) 2 — Form of Stock Option Award Agreement for Executive Officers of Southern Company under the Southern Company Omnibus Incentive Compensation Plan. (Designated in Southern Company's Form 10-Q for the quarter ended March 31, 2011, File No. 1-3526, as Exhibit 10 (a)3.)

\# (a) 3 — Deferred Compensation Plan for Directors of The Southern Company, Amended and Restated effective January 1, 2008. (Designated in Southern Company's Form 10-K for the year ended December 31, 2007, File No. 1-3526, as Exhibit 10(a)3.)

\# (a) 4 — Southern Company Deferred Compensation Plan as amended and restated as of January 1, 2009 and First Amendment thereto effective January 1, 2010. (Designated in Southern Company's Form 10-K for the year ended December 31, 2008, File No. 1-3526, as Exhibit 10 (a)4 and in Southern Company's Form 10-K for the year ended December 31, 2009, File No. 1-3526, as Exhibit 10(a)5.)

\# (a) 5 — Outside Directors Stock Plan for The Southern Company and its Subsidiaries, effective May 26, 2004. (Designated in Southern Company's Form 10-Q for the quarter ended June 30, 2004, File No. 1-3526, as Exhibit 10(a)2.)

#	(a)	6	—	The Southern Company Supplemental Executive Retirement Plan, Amended and Restated effective January 1, 2009 and First Amendment thereto effective January 1, 2010. (Designated in Southern Company's Form 10-K for the year ended December 31, 2008, File No. 1-3526, as Exhibit 10(a)6 and in Southern Company's Form 10-K for the year ended December 31, 2009, File No. 1-3526, as Exhibit 10(a)(8).)
#	(a)	7	—	The Southern Company Supplemental Benefit Plan, Amended and Restated effective as of January 1, 2009 and First Amendment thereto effective January 1, 2010. (Designated in Southern Company's Form 10-K for the year ended December 31, 2008, File No. 1-3526, as Exhibit 10(a)7 and in Southern Company's Form 10-K for the year ended December 31, 2009, File No. 1-3526, as Exhibit 10(a)10.)
#	(a)	8	—	Consulting Agreement by and with Southern Company Services, Inc. and Anthony J. Topazi effective August 1, 2012. (Designated in Southern Company's Form 10-Q for the quarter ended June 30, 2012, File No. 1-3526, as Exhibit 10(a)2.)
#	(a)	9	—	Retention and Restricted Stock Unit Award Agreement by and between Southern Company and Charles D. McCrary effective May 22, 2012. (Designated in Southern Company's Form 10-Q for the quarter ended June 30, 2012, File No. 1-3526, as Exhibit 10(a)1.)
#	(a)	10	—	The Southern Company Change in Control Benefits Protection Plan, effective December 31, 2008. (Designated in Form 8-K dated December 31, 2008, File No. 1-3526, as Exhibit 10.1.)
#	(a)	11	—	Southern Company Deferred Compensation Trust Agreement as amended and restated effective January 1, 2001 between Wells Fargo Bank, N.A., as successor to Wachovia Bank, N.A., Southern Company, SCS, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, SouthernLINC Wireless, Southern Company Energy Solutions, LLC, and Southern Nuclear and First Amendment thereto effective January 1, 2009. (Designated in Southern Company's Form 10-K for the year ended December 31, 2000, File No. 1-3526, as Exhibit 10 (a)103 and in Southern Company's Form 10-K for the year ended December 31, 2008, File No. 1-3526, as Exhibit 10(a)16.)
#	(a)	12	—	Deferred Stock Trust Agreement for Directors of Southern Company and its subsidiaries, dated as of January 1, 2000, between Reliance Trust Company, Southern Company, Alabama Power, Georgia Power, Gulf Power, and Mississippi Power and First Amendment thereto effective January 1, 2009. (Designated in Southern Company's Form 10-K for the year ended December 31, 2000, File No. 1-3526, as Exhibit 10(a)104 and in Southern Company's Form 10-K for the year ended December 31, 2008, File No. 1-3526, as Exhibit 10(a)18.)
#	(a)	13	—	Amended and Restated Deferred Cash Compensation Trust Agreement for Directors of Southern Company and its subsidiaries, effective September 1, 2001, between Wells Fargo Bank, N.A., as successor to Wachovia Bank, N.A., Southern Company, Alabama Power, Georgia Power, Gulf Power, and Mississippi Power and First Amendment thereto effective January 1, 2009. (Designated in Southern Company's Form 10-K for the year ended December 31, 2001, File No. 1-3526, as Exhibit 10(a)92 and in Southern Company's Form 10-K for the year ended December 31, 2008, File No. 1-3526, as Exhibit 10(a)20.)
#	(a)	14	—	Amended and Restated Southern Company Senior Executive Change in Control Severance Plan effective December 31, 2008, First Amendment thereto effective January 1, 2010, and Second Amendment thereto effective February 23, 2011. (Designated in Southern Company's Form 10-K for the year ended December 31, 2008, File No. 1-3526, as Exhibit 10(a)23, in Southern Company's Form 10-K for the year ended December 31, 2009, File No. 1-3526, as Exhibit 10(a)22, and in Southern Company's Form 10-K for the year ended December 31, 2010, File No. 1-3526, as Exhibit 10(a)16.)
#	(a)	15	—	Southern Company Executive Change in Control Severance Plan, Amended and Restated effective December 31, 2008 and First Amendment thereto effective January 1, 2010. (Designated in Southern Company's Form 10-K for the year ended December 31, 2008, File No. 1-3526, as Exhibit 10(a)24 and in Southern Company's Form 10-K for the year ended December 31, 2009, File No. 1-3526, as Exhibit 10(a)24.)
# *	(a)	16	—	Base Salaries of Named Executive Officers.
#	(a)	17	—	Summary of Non-Employee Director Compensation Arrangements. (Designated in Form 10-Q for the quarter ended March 31, 2011, File No. 1-3526, as Exhibit 10(a)5.)
#	(a)	18	—	Form of Terms for Performance Share Awards granted under the Southern Company Omnibus Incentive Compensation Plan. (Designated in Form 8-K dated February 9, 2010, File No. 1-3526, as Exhibit 10.1.)
#	(a)	19	—	Restricted Stock Award Agreement between Southern Company and W. Paul Bowers dated July 27, 2010. (Designated in Form 10-Q for the quarter ended September 30, 2010, File No. 1-3526, as Exhibit 10(a)2.)

Alabama Power

	(b)	1	—	Intercompany Interchange Contract as revised effective May 1, 2007, among Alabama Power, Georgia Power, Gulf Power, Mississippi Power, Southern Power, and SCS. (Designated in Form 10-Q for the quarter ended March 31, 2007, File No. 1-3164, as Exhibit 10(b)5.)
#	(b)	2	—	Southern Company 2011 Omnibus Incentive Compensation Plan, effective May 25, 2011. See Exhibit 10(a)1 herein.
#	(b)	3	—	Form of Stock Option Award Agreement for Executive Officers of Southern Company under the Southern Company Omnibus Incentive Compensation Plan. See Exhibit 10(a)2 herein.
#	(b)	4	—	Southern Company Deferred Compensation Plan as amended and restated as of January 1, 2009 and First Amendment thereto effective January 1, 2010. See Exhibit 10(a)4 herein.
#	(b)	5	—	Outside Directors Stock Plan for The Southern Company and its Subsidiaries, effective May 26, 2004. See Exhibit 10(a)5 herein.
#	(b)	6	—	The Southern Company Supplemental Executive Retirement Plan, Amended and Restated effective January 1, 2009 and First Amendment thereto effective January 1, 2010. See Exhibit 10(a)6 herein.
#	(b)	7	—	The Southern Company Supplemental Benefit Plan, Amended and Restated effective as of January 1, 2009 and First Amendment thereto effective January 1, 2010. See Exhibit 10(a)7 herein.
#	(b)	8	—	Southern Company Executive Change in Control Severance Plan, Amended and Restated effective December 31, 2008 and First Amendment thereto effective January 1, 2010. See Exhibit 10(a)15 herein.
#	(b)	9	—	Deferred Compensation Plan for Directors of Alabama Power Company, Amended and Restated effective January 1, 2008. (Designated in Alabama Power's Form 10-Q for the quarter ended June 30, 2008, File No. 1-3164, as Exhibit 10(b)1.)
#	(b)	10	—	The Southern Company Change in Control Benefits Protection Plan, effective December 31, 2008. See Exhibit 10(a)10 herein.
#	(b)	11	—	Southern Company Deferred Compensation Trust Agreement as amended and restated effective January 1, 2001 between Wells Fargo Bank, N.A., as successor to Wachovia Bank, N.A., Southern Company, SCS, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, SouthernLINC Wireless, Southern Company Energy Solutions, LLC, and Southern Nuclear and First Amendment thereto effective January 1, 2009. See Exhibit 10(a)11 herein.
#	(b)	12	—	Deferred Stock Trust Agreement for Directors of Southern Company and its subsidiaries, dated as of January 1, 2000, between Reliance Trust Company, Southern Company, Alabama Power, Georgia Power, Gulf Power, and Mississippi Power and First Amendment thereto effective January 1, 2009. See Exhibit 10(a)12 herein.
#	(b)	13	—	Amended and Restated Deferred Cash Compensation Trust Agreement for Directors of Southern Company and its subsidiaries, effective September 1, 2001, between Wells Fargo Bank, N.A., as successor to Wachovia Bank, N.A., Southern Company, Alabama Power, Georgia Power, Gulf Power, and Mississippi Power and First Amendment thereto effective January 1, 2009. See Exhibit 10(a)13 herein.
#	(b)	14	—	Amended and Restated Southern Company Senior Executive Change in Control Severance Plan effective December 31, 2008, First Amendment thereto effective January 1, 2010, and Second Amendment thereto effective February 23, 2011. See Exhibit 10(a)14 herein.
# *	(b)	15	—	Base Salaries of Named Executive Officers.
#	(b)	16	—	Summary of Non-Employee Director Compensation Arrangements. (Designated in Alabama Power's Form 10-Q for the quarter ended June 30, 2010, File No. 1-3164, as Exhibit 10(b)1.)
#	(b)	17	—	Form of Terms for Performance Share Awards granted under the Southern Company Omnibus Incentive Compensation Plan. See Exhibit 10(a)18 herein.
#	(b)	18	—	Deferred Compensation Agreement between Southern Company, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, and SCS and Philip C. Raymond dated September 15, 2010. (Designated in Alabama Power's Form 10-Q for the quarter ended September 30, 2010, File No. 1-3164, as Exhibit 10(b)2.)
#	(b)	19		Retention and Restricted Stock Unit Award Agreement by and between Southern Company and Charles D. McCrary effective May 22, 2012. See Exhibit 10(a)9 herein.

Georgia Power

	(c)	1	—	Intercompany Interchange Contract as revised effective May 1, 2007, among Alabama Power, Georgia Power, Gulf Power, Mississippi Power, Southern Power, and SCS. See Exhibit 10(b) 1 herein.

	(c)	2	—	Revised and Restated Integrated Transmission System Agreement dated as of November 12, 1990, between Georgia Power and OPC. (Designated in Georgia Power's Form 10-K for the year ended December 31, 1990, File No. 1-6468, as Exhibit 10(g).)
	(c)	3	—	Revised and Restated Integrated Transmission System Agreement between Georgia Power and Dalton dated as of December 7, 1990. (Designated in Georgia Power's Form 10-K for the year ended December 31, 1990, File No. 1-6468, as Exhibit 10(gg).)
	(c)	4	—	Revised and Restated Integrated Transmission System Agreement between Georgia Power and MEAG Power dated as of December 7, 1990. (Designated in Georgia Power's Form 10-K for the year ended December 31, 1990, File No. 1-6468, as Exhibit 10(hh).)
#	(c)	5	—	Southern Company 2011 Omnibus Incentive Compensation Plan, effective May 25, 2011. See Exhibit 10(a)1 herein.
#	(c)	6	—	Form of Stock Option Award Agreement for Executive Officers of Southern Company under the Southern Company Omnibus Incentive Compensation Plan. See Exhibit 10(a)2 herein.
#	(c)	7	—	Southern Company Deferred Compensation Plan as amended and restated as of January 1, 2009 and First Amendment thereto effective January 1, 2010. See Exhibit 10(a)4 herein.
#	(c)	8	—	Outside Directors Stock Plan for The Southern Company and its Subsidiaries, effective May 26, 2004. See Exhibit 10(a)5 herein.
#	(c)	9	—	The Southern Company Supplemental Executive Retirement Plan, Amended and Restated effective January 1, 2009 and First Amendment thereto effective January 1, 2010. See Exhibit 10(a)6 herein.
#	(c)	10	—	The Southern Company Supplemental Benefit Plan, Amended and Restated effective as of January 1, 2009 and First Amendment thereto effective January 1, 2010. See Exhibit 10(a)7 herein.
#	(c)	11	—	Southern Company Executive Change in Control Severance Plan, Amended and Restated effective December 31, 2008 and First Amendment thereto effective January 1, 2010. See Exhibit 10(a)15 herein.
#	(c)	12	—	Deferred Compensation Plan For Directors of Georgia Power Company, Amended and Restated Effective January 1, 2008. (Designated in Form 10-K for the year ended December 31, 2007, File No. 1-6468, as Exhibit 10(c)12.)
#	(c)	13	—	The Southern Company Change in Control Benefits Protection Plan, effective December 31, 2008. See Exhibit 10(a)10 herein.
#	(c)	14	—	Southern Company Deferred Compensation Trust Agreement as amended and restated effective January 1, 2001 between Wells Fargo Bank, N.A., as successor to Wachovia Bank, N.A., Southern Company, SCS, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, SouthernLINC Wireless, Southern Company Energy Solutions, LLC, and Southern Nuclear and First Amendment thereto effective January 1, 2009. See Exhibit 10(a)11 herein.
#	(c)	15	—	Deferred Stock Trust Agreement for Directors of Southern Company and its subsidiaries, dated as of January 1, 2000, between Reliance Trust Company, Southern Company, Alabama Power, Georgia Power, Gulf Power, and Mississippi Power and First Amendment thereto effective January 1, 2009. See Exhibit 10(a)12 herein.
#	(c)	16	—	Amended and Restated Deferred Cash Compensation Trust Agreement for Directors of Southern Company and its subsidiaries, effective September 1, 2001, between Wells Fargo Bank, N.A., as successor to Wachovia Bank, N.A., Southern Company, Alabama Power, Georgia Power, Gulf Power, and Mississippi Power and First Amendment thereto effective January 1, 2009. See Exhibit 10(a)13 herein.
#	(c)	17	—	Amended and Restated Southern Company Senior Executive Change in Control Severance Plan effective December 31, 2008, First Amendment thereto effective January 1, 2010, and Second Amendment thereto effective February 23, 2011. See Exhibit 10(a)14 herein.
# *	(c)	18	—	Base Salaries of Named Executive Officers.
#	(c)	19	—	Summary of Non-Employee Director Compensation Arrangements. (Designated in Georgia Power's Form 10-K for the year ended December 31, 2009, File No. 1-6468, as Exhibit 10(c) 26.)

	(c)	20	—	Engineering, Procurement and Construction Agreement, dated as of April 8, 2008, between Georgia Power, for itself and as agent for OPC, MEAG Power, and Dalton, as owners, and a consortium consisting of Westinghouse Electric Company LLC and Stone & Webster, Inc., as contractor, for Units 3 & 4 at the Vogtle Electric Generating Plant Site, Amendment No. 1 thereto dated as of December 11, 2009, Amendment No. 2 thereto dated as of January 15, 2010, Amendment No. 3 thereto dated as of February 23, 2010, Amendment No. 4 thereto dated as of May 2, 2011, and Amendment No. 5 thereto dated as of February 7, 2012. (Georgia Power requested confidential treatment for certain portions of these documents pursuant to applications for confidential treatment sent to the SEC. Georgia Power omitted such portions from the filings and filed them separately with the SEC.) (Designated in Form 10-Q/A for the quarter ended June 30, 2008, File No. 1-6468, as Exhibit 10(c)1, in Form 10-K for the year ended December 31, 2009, File No. 1-6468, as Exhibit 10(c)29, in Georgia Power's Form 10-Q for the quarter ended March 31, 2010, File No. 1-6468, as Exhibits 10(c) 1 and 10(c)2, in Georgia Power's Form 10-Q for the quarter ended June 30, 2011, File No. 1-6468, as Exhibit 10(c)2, and in Georgia Power's Form 10-Q for the quarter ended March 31, 2012, File No. 1-6468, as Exhibit 10(c)2.)
#	(c)	21	—	Form of Terms for Performance Share Awards granted under the Southern Company Omnibus Incentive Compensation Plan. See Exhibit 10(a)18 herein.
#	(c)	22	—	Restricted Stock Award Agreement between Southern Company and W. Paul Bowers dated July 27, 2010. See Exhibit 10(a)19 herein.
#	(c)	23	—	Retention Agreement between Georgia Power and Michael A. Brown, effective January 1, 2011. (Designated in Form 10-Q for the quarter ended March 31, 2011, File No. 1-6468, as Exhibit 10(c)1.)
# *	(c)	24	—	Retention Award Agreement between Southern Nuclear and Joseph A. Miller, effective January 1, 2013.
# *	(c)	25	—	Amendment to Retention Award Agreement between Southern Nuclear and Joseph A. Miller, effective January 1, 2013.
Gulf Power				
	(d)	1	—	Intercompany Interchange Contract as revised effective May 1, 2007, among Alabama Power, Georgia Power, Gulf Power, Mississippi Power, Southern Power, and SCS. See Exhibit 10(b) 1 herein.
#	(d)	2	—	Southern Company 2011 Omnibus Incentive Compensation Plan, effective May 25, 2011. See Exhibit 10(a)1 herein.
#	(d)	3	—	Form of Stock Option Award Agreement for Executive Officers of Southern Company under the Southern Company Omnibus Incentive Compensation Plan. See Exhibit 10(a)2 herein.
#	(d)	4	—	Southern Company Deferred Compensation Plan as amended and restated as of January 1, 2009 and First Amendment thereto effective January 1, 2010. See Exhibit 10(a)4 herein.
#	(d)	5	—	Outside Directors Stock Plan for The Southern Company and its Subsidiaries, effective May 26, 2004. See Exhibit 10(a)5 herein.
#	(d)	6	—	The Southern Company Supplemental Benefit Plan, Amended and Restated effective as of January 1, 2009 and First Amendment thereto effective January 1, 2010. See Exhibit 10(a)7 herein.
#	(d)	7	—	Southern Company Executive Change in Control Severance Plan, Amended and Restated effective December 31, 2008 and First Amendment thereto effective January 1, 2010. See Exhibit 10(a)15 herein.
#	(d)	8	—	The Southern Company Supplemental Executive Retirement Plan, Amended and Restated effective January 1, 2009 and First Amendment thereto effective January 1, 2010. See Exhibit 10(a)6 herein.
#	(d)	9	—	Deferred Compensation Plan For Outside Directors of Gulf Power Company, Amended and Restated effective January 1, 2008. (Designated in Gulf Power's Form 10-Q for the quarter ended March 31, 2008, File No. 0-2429, as Exhibit 10(d)1.)
#	(d)	10	—	The Southern Company Change in Control Benefits Protection Plan, effective December 31, 2008. See Exhibit 10(a)10 herein.
#	(d)	11	—	Southern Company Deferred Compensation Trust Agreement as amended and restated effective January 1, 2001 between Wells Fargo Bank, N.A., as successor to Wachovia Bank, N.A., Southern Company, SCS, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, SouthernLINC Wireless, Southern Company Energy Solutions, LLC, and Southern Nuclear and First Amendment thereto effective January 1, 2009. See Exhibit 10(a)11 herein.

#	(d)	12	—	Deferred Stock Trust Agreement for Directors of Southern Company and its subsidiaries, dated as of January 1, 2000, between Reliance Trust Company, Southern Company, Alabama Power, Georgia Power, Gulf Power, and Mississippi Power and First Amendment thereto effective January 1, 2009. See Exhibit 10(a)12 herein.
#	(d)	13	—	Amended and Restated Deferred Cash Compensation Trust Agreement for Directors of Southern Company and its subsidiaries, effective September 1, 2001, between Wells Fargo Bank, N.A., as successor to Wachovia Bank, N.A., Southern Company, Alabama Power, Georgia Power, Gulf Power, and Mississippi Power and First Amendment thereto effective January 1, 2009. See Exhibit 10(a)13 herein.
#	(d)	14	—	Amended and Restated Southern Company Senior Executive Change in Control Severance Plan effective December 31, 2008, First Amendment thereto effective January 1, 2010, and Second Amendment thereto effective February 23, 2011. See Exhibit 10(a)14 herein.
# *	(d)	15	—	Base Salaries of Named Executive Officers.
#	(d)	16	—	Summary of Non-Employee Director Compensation Arrangements. (Designated in Gulf Power's Form 10-Q for the quarter ended June 30, 2010, File No. 001-31737, as Exhibit 10(d) 1.)
	(d)	17	—	Power Purchase Agreement between Gulf Power and Shell Energy North America (US), L.P. dated March 16, 2009. (Designated in Gulf Power's Form 10-Q for the quarter ended March 31, 2009, File No. 001-31737, as Exhibit 10(d)1.) (Gulf Power requested confidential treatment for certain portions of this document pursuant to an application for confidential treatment sent to the SEC. Gulf Power omitted such portions from this filing and filed them separately with the SEC.)
#	(d)	18	—	Form of Terms for Performance Share Awards granted under the Southern Company Omnibus Incentive Compensation Plan. See Exhibit 10(a)18 herein.
#	(d)	19	—	Deferred Compensation Agreement between Southern Company, Georgia Power, Gulf Power, and Southern Nuclear and Bentina C. Terry dated August 1, 2010. (Designated in Gulf Power's Form 10-Q for the quarter ended September 30, 2010, File No. 001-31737, as Exhibit 10(d)2.)
#	(d)	20	—	Deferred Compensation Agreement between Southern Company, Alabama Power, and SCS and Mark A. Crosswhite dated July 30, 2008. (Designated in Alabama Power's Form 10-K for the year ended December 31, 2009, File No. 1-3164, as Exhibit 10(b)21.)
Mississippi Power				
	(e)	1	—	Intercompany Interchange Contract as revised effective May 1, 2007, among Alabama Power, Georgia Power, Gulf Power, Mississippi Power, Southern Power, and SCS. See Exhibit 10(b) 1 herein.
	(e)	2	—	Transmission Facilities Agreement dated February 25, 1982, Amendment No. 1 dated May 12, 1982 and Amendment No. 2 dated December 6, 1983, between Entergy Corporation (formerly Gulf States) and Mississippi Power. (Designated in Mississippi Power's Form 10-K for the year ended December 31, 1981, File No. 001-11229, as Exhibit 10(f), in Mississippi Power's Form 10-K for the year ended December 31, 1982, File No. 001-11229, as Exhibit 10 (f)(2), and in Mississippi Power's Form 10-K for the year ended December 31, 1983, File No. 001-11229, as Exhibit 10(f)(3).)
#	(e)	3	—	Southern Company 2011 Omnibus Incentive Compensation Plan, effective May 25, 2011. See Exhibit 10(a)1 herein.
#	(e)	4	—	Form of Stock Option Award Agreement for Executive Officers of Southern Company under the Southern Company Omnibus Incentive Compensation Plan. See Exhibit 10(a)2 herein.
#	(e)	5	—	Southern Company Deferred Compensation Plan as amended and restated as of January 1, 2009 and First Amendment thereto effective January 1, 2010. See Exhibit 10(a)4 herein.
#	(e)	6	—	Outside Directors Stock Plan for The Southern Company and its Subsidiaries, effective May 26, 2004. See Exhibit 10(a)5 herein.
#	(e)	7	—	The Southern Company Supplemental Benefit Plan, Amended and Restated effective as of January 1, 2009 and First Amendment thereto effective January 1, 2010. See Exhibit 10(a)7 herein.
#	(e)	8	—	Southern Company Executive Change in Control Severance Plan, Amended and Restated effective December 31, 2008 and First Amendment thereto effective January 1, 2010. See Exhibit 10(a)15 herein.
#	(e)	9	—	The Southern Company Supplemental Executive Retirement Plan, Amended and Restated effective January 1, 2009 and First Amendment thereto effective January 1, 2010. See Exhibit 10(a)6 herein.

#	(e)	10	—	Deferred Compensation Plan for Outside Directors of Mississippi Power Company, Amended and Restated effective January 1, 2008. (Designated in Mississippi Power's Form 10-Q for the quarter ended March 31, 2008, File No. 001-11229 as Exhibit 10(e)1.)
#	(e)	11	—	The Southern Company Change in Control Benefits Protection Plan, effective December 31, 2008. See Exhibit 10(a)10 herein.
#	(e)	12	—	Southern Company Deferred Compensation Trust Agreement as amended and restated effective January 1, 2001 between Wells Fargo Bank, N.A., as successor to Wachovia Bank, N.A., Southern Company, SCS, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, SouthernLINC Wireless, Southern Company Energy Solutions, LLC, and Southern Nuclear and First Amendment thereto effective January 1, 2009. See Exhibit 10(a)11 herein.
#	(e)	13	—	Deferred Stock Trust Agreement for Directors of Southern Company and its subsidiaries, dated as of January 1, 2000, between Reliance Trust Company, Southern Company, Alabama Power, Georgia Power, Gulf Power, and Mississippi Power and First Amendment thereto effective January 1, 2009. See Exhibit 10(a)12 herein.
#	(e)	14	—	Amended and Restated Deferred Cash Compensation Trust Agreement for Directors of Southern Company and its subsidiaries, effective September 1, 2001, between Wells Fargo Bank, N.A., as successor to Wachovia Bank, N.A., Southern Company, Alabama Power, Georgia Power, Gulf Power, and Mississippi Power and First Amendment thereto effective January 1, 2009. See Exhibit 10(a)13 herein.
#	(e)	15	—	Amended and Restated Southern Company Senior Executive Change in Control Severance Plan effective December 31, 2008 and First Amendment thereto effective January 1, 2010. See Exhibit 10(a)14 herein.
# *	(e)	16	—	Base Salaries of Named Executive Officers.
#	(e)	17	—	Summary of Non-Employee Director Compensation Arrangements. (Designated in Mississippi Power's Form 10-K for the year ended December 31, 2009, File No. 001-11229, as Exhibit 10(e)22.)
	(e)	18	—	Cooperative Agreement between the DOE and SCS dated as of December 12, 2008. (Designated in Mississippi Power's Form 10-K for the year ended December 31, 2008, File No. 001-11229, as Exhibit 10(e)22.) (Mississippi Power requested confidential treatment for certain portions of this document pursuant to an application for confidential treatment sent to the SEC. Mississippi Power omitted such portions from this filing and filed them separately with the SEC.)
#	(e)	19	—	Form of Terms for Performance Share Awards granted under the Southern Company Omnibus Incentive Compensation Plan. See Exhibit 10(a)18 herein.

Southern Power

(f)	1	—	Service contract dated as of January 1, 2001, between SCS and Southern Power. (Designated in Southern Company's Form 10-K for the year ended December 31, 2001, File No. 1-3526, as Exhibit 10(a)(2).)
(f)	2	—	Intercompany Interchange Contract as revised effective May 1, 2007, among Alabama Power, Georgia Power, Gulf Power, Mississippi Power, Southern Power, and SCS. See Exhibit 10(b) 1 herein.

(14) Code of Ethics

Southern Company

(a)	—	The Southern Company Code of Ethics. (Designated in Southern Company's Form 10-K for the year ended December 31, 2009, File No. 1-3526, as Exhibit 14(a).)

Alabama Power

(b)	—	The Southern Company Code of Ethics. See Exhibit 14(a) herein.

Georgia Power

(c)	—	The Southern Company Code of Ethics. See Exhibit 14(a) herein.

Gulf Power

(d)	—	The Southern Company Code of Ethics. See Exhibit 14(a) herein.

Mississippi Power

(e)	—	The Southern Company Code of Ethics. See Exhibit 14(a) herein.

Southern Power

(f)	—	The Southern Company Code of Ethics. See Exhibit 14(a) herein.

(21) Subsidiaries of Registrants

Southern Company

* (a) — Subsidiaries of Registrant.

Alabama Power

(b) — Subsidiaries of Registrant. See Exhibit 21(a) herein.

Georgia Power

(c) — Subsidiaries of Registrant. See Exhibit 21(a) herein.

Gulf Power

(d) — Subsidiaries of Registrant. See Exhibit 21(a) herein.

Mississippi Power

(e) — Subsidiaries of Registrant. See Exhibit 21(a) herein.

Southern Power

Omitted pursuant to General Instruction I(2)(b) of Form 10-K.

(23) Consents of Experts and Counsel

Southern Company

* (a) 1 — Consent of Deloitte & Touche LLP.

Alabama Power

* (b) 1 — Consent of Deloitte & Touche LLP.

Georgia Power

* (c) 1 — Consent of Deloitte & Touche LLP.

Gulf Power

* (d) 1 — Consent of Deloitte & Touche LLP.

Mississippi Power

* (e) 1 — Consent of Deloitte & Touche LLP.

Southern Power

* (f) 1 — Consent of Deloitte & Touche LLP.

(24) Powers of Attorney and Resolutions

Southern Company

* (a) — Power of Attorney and resolution.

Alabama Power

* (b) — Power of Attorney and resolution.

Georgia Power

* (c) — Power of Attorney and resolution.

Gulf Power

* (d) — Power of Attorney and resolution.

Mississippi Power

* (e) — Power of Attorney and resolution.

Southern Power

* (f) — Power of Attorney and resolution.

(31) Section 302 Certifications

Southern Company

* (a) 1 — Certificate of Southern Company's Chief Executive Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.

* (a) 2 — Certificate of Southern Company's Chief Financial Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.

Alabama Power

* (b) 1 — Certificate of Alabama Power's Chief Executive Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.

*	(b)	2	—	Certificate of Alabama Power's Chief Financial Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.

Georgia Power

*	(c)	1	—	Certificate of Georgia Power's Chief Executive Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.
*	(c)	2	—	Certificate of Georgia Power's Chief Financial Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.

Gulf Power

*	(d)	1	—	Certificate of Gulf Power's Chief Executive Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.
*	(d)	2	—	Certificate of Gulf Power's Chief Financial Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.

Mississippi Power

*	(e)	1	—	Certificate of Mississippi Power's Chief Executive Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.
*	(e)	2	—	Certificate of Mississippi Power's Chief Financial Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.

Southern Power

*	(f)	1	—	Certificate of Southern Power's Chief Executive Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.
*	(f)	2	—	Certificate of Southern Power's Chief Financial Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.

(32) Section 906 Certifications

Southern Company

*	(a)	-	Certificate of Southern Company's Chief Executive Officer and Chief Financial Officer required by Section 906 of the Sarbanes-Oxley Act of 2002.

Alabama Power

*	(b)	-	Certificate of Alabama Power's Chief Executive Officer and Chief Financial Officer required by Section 906 of the Sarbanes-Oxley Act of 2002.

Georgia Power

*	(c)	-	Certificate of Georgia Power's Chief Executive Officer and Chief Financial Officer required by Section 906 of the Sarbanes-Oxley Act of 2002.

Gulf Power

*	(d)	-	Certificate of Gulf Power's Chief Executive Officer and Chief Financial Officer required by Section 906 of the Sarbanes-Oxley Act of 2002.

Mississippi Power

*	(e)	-	Certificate of Mississippi Power's Chief Executive Officer and Chief Financial Officer required by Section 906 of the Sarbanes-Oxley Act of 2002.

Southern Power

*	(f)	-	Certificate of Southern Power's Chief Executive Officer and Chief Financial Officer required by Section 906 of the Sarbanes-Oxley Act of 2002.

(101) XBRL-Related Documents

*	INS	-	XBRL Instance Document
*	SCH	-	XBRL Taxonomy Extension Schema Document
*	CAL	-	XBRL Taxonomy Calculation Linkbase Document
*	DEF	-	XBRL Definition Linkbase Document
*	LAB	-	XBRL Taxonomy Label Linkbase Document
*	PRE	-	XBRL Taxonomy Presentation Linkbase Document

FILED JUL 12, 2013
DOCUMENT NO. 03980-13
FPSC - COMMISSION CLERK

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 130140-EI

GULF POWER
A SOUTHERN COMPANY

MINIMUM FILING REQUIREMENTS

SECTION F – MISCELLANEOUS SCHEDULES
VOLUME TWO

GULF POWER COMPANY

Docket No. 130140-EI
Minimum Filing Requirements

Index

F. Miscellaneous Schedules
Volume Two

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FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Provide a copy of the "Business Contracts with Officers, Directors, and Affiliates" schedule included in the company's most recently filed Annual Report as required by Rule 25-6.135, Florida Administrative Code. Provide any subsequent changes affecting the test year.

Type of Data Shown:
___Projected Test Year Ended 12/31/14
___Prior Year Ended 12/31/13
_X_Historical Year Ended 12/31/12
Witness: R. S. Teel

(1) Line No.	(2) Name of Officer or Director	(3) Name and Address of Affiliated Entity	(4) Relationship With Affiliated Entity	(5) Amount of Contract or Transaction	(6) Description of Product or Service
1	See attached schedule. Note the following change for subsequent years:				
2	William A. Pullum retired, effective May 14, 2012.				
3	Mark A. Crosswhite resigned, effective June 30, 2012.				
4	Stanley W. Connally, Jr. elected, effective July 1, 2012.				

Business Contracts with Officers, Directors and Affiliates

Company: Gulf Power Company

For the Year Ended December 31, 2012

List all contracts, agreements, or other business arrangements* entered into during the calendar year (other than compensation-related to position with respondent) between the respondent and each officer and director listed in Part 1 of the Executive Summary. In addition, provide the same information with respect to professional services for each firm, partnership, or organization with which the officer or director is affiliated.

Note * Business agreement, for this schedule, shall mean any oral or written business deal which binds the concerned parties for products or services during the reporting year or future years.

Name of Officer or Director	Name and Address of Affiliated Entity	Amount	Identification of Product or Service
J. Mort O'Sullivan, III	Warren Averett O'Sullivan Creel 316 S. Baylen St., Suite 300 Pensacola, FL 32502	1,000.00	Accounting Services
William Cramer	Bill Cramer Chevrolet Cadillac Buick GMC, Inc. 2251 West 23rd Street Panama City, Florida 32405	203.90	Car Leasing
William Cramer	Bill Cramer Chevrolet Cadillac Buick GMC, Inc. 2251 West 23rd Street Panama City, Florida 32405	2,058.74	Car Leasing

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Supply a copy of all NRC safety citations issued against the company within the last two years, a listing of corrective actions and a listing of any outstanding deficiencies. For each citation provide the dollar amount of any fines or penalties assessed against the company and account(s) each are recorded.

Type of Data Shown:
____ Projected Test Year Ended 12/31/14
____ Prior Year Ended 12/31/13
_X_ Historical Year Ended 12/31/11-12/31/12
Witness: M. L. Burroughs

Line No.	
1	Not applicable. Gulf has no nuclear facilities.

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: If a projected test year is used, provide a brief description of each method or model used in the forecasting process. Provide a flow chart which shows the position of each model in the forecasting process.

Type of Data Shown:
X Projected Test Year Ended 12/31/14
_ Prior Year Ended 12/31/13
_ Historical Year Ended 12/31/12
Witness: S. D. Ritenour, R. J. Alexander, M. L. Burroughs, R. W. Grove

		Witness	Page
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FLORIDA PUBLIC SERVICE COMMISSION

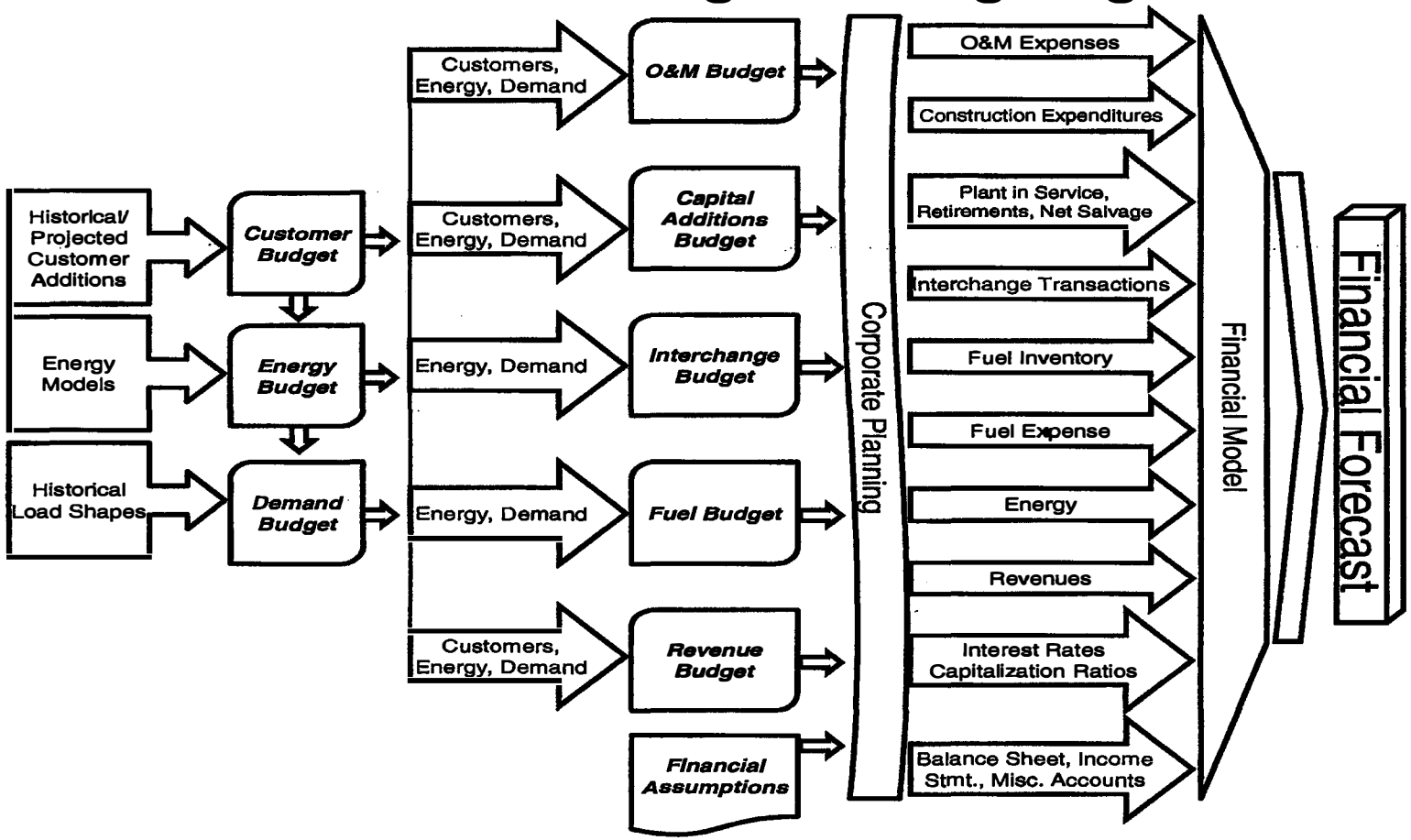
COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: If a projected test year is used, provide a brief description of each method or model used in the forecasting process. Provide a flow chart which shows the position of each model in the forecasting process.

Type of Data Shown:
X Projected Test Year Ended 12/31/14
_ Prior Year Ended 12/31/13
_ Historical Year Ended 12/31/12
Witness: S. D. Ritenour, R. J. Alexander, M. L. Burroughs, R. W. Grove

Gulf Power Planning and Budgeting Process



Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: If a projected test year is used, provide a brief description of each method or model used in the forecasting process. Provide a flow chart which shows the position of each model in the forecasting process.

Type of Data Shown:
X Projected Test Year Ended 12/31/14
_ Prior Year Ended 12/31/13
_ Historical Year Ended 12/31/12
Witness: S. D. Ritenour, R. J. Alexander, M. L. Burroughs, R. W. Grove

I. OVERVIEW

This schedule describes the process Gulf Power uses in developing its annual financial forecast. The financial forecast is comprised of eight component budgets which are used by management to assess departmental performance and to control the Company's operations and activities. Gulf's financial forecast is a logically developed and detailed tool that management uses in making decisions affecting the future direction of the Company.

Gulf's forecasting process is outlined on the flow chart on page 2 of this schedule. The chart shows the process beginning with information obtained by the Forecasting Department which leads to the development of the customer, energy, and demand budgets. These budgets in turn provide the basis for developing the revenue, fuel, interchange, capital additions, and operations and maintenance budgets. Although not reflected on the chart, there are numerous management reviews of each budget, along with approval of the capital additions budget by the Board of Directors.

A list of assumptions that are incorporated in the eight component budgets of Gulf's financial forecast are shown on MFR Schedule F-8. The information and budgets included in the eight component budgets along with other financial assumptions and data are input to Gulf's Financial Model which generates the accounting statements that comprise the Company's financial forecast. The 2013 financial forecast of 2014 is the basis of the test year data in this proceeding.

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: If a projected test year is used, provide a brief description of each method or model used in the forecasting process. Provide a flow chart which shows the position of each model in the forecasting process.

Type of Data Shown:
X Projected Test Year Ended 12/31/14
_ Prior Year Ended 12/31/13
_ Historical Year Ended 12/31/12
Witness: S. D. Ritenour, R. J. Alexander, M. L. Burroughs, R. W. Grove

II. CUSTOMER, ENERGY, PEAK DEMAND, & REVENUE FORECASTS

Methodology Overview

Gulf annually produces a new forecast of customers, energy, peak demand and retail base rate revenue. Gulf begins by projecting the number of new non-lighting customers it expects to add in each customer class – residential, commercial and industrial. Next, Gulf estimates how much energy these customers will use under normal weather conditions. For customers on demand rates, Gulf then estimates monthly billing demands. Finally, the base charges, energy charges, and demand charges from the appropriate rate schedules are applied to the number of customers, monthly energy and aggregate monthly billing demands to estimate retail base rate revenues. Outdoor lighting customers, energy and base rate revenue are projected by rate and class. Gulf also forecasts total Company peak demand using total energy projections and historical relationships between energy and demand. Additional detail is supplied in Gulf Witness Alexander's testimony.

Fuel, Purchased Power Capacity, Conservation and Environmental Clause revenues are calculated by the Financial Model based on energy and recoverable fuel, purchased power, environmental, and conservation costs. These factors are then multiplied times the billed energy by rate class to arrive at the respective clause revenues.

Other Operating Revenues include miscellaneous service revenues (including franchise fees), rent from electric property, and other miscellaneous revenue. Franchise fee revenues (net of revenue taxes) are projected to equal the franchise fee expense which is calculated by the Financial Model. The remaining revenue items are projected by the Corporate Planning Department.

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: If a projected test year is used, provide a brief description of each method or model used in the forecasting process. Provide a flow chart which shows the position of each model in the forecasting process.

Type of Data Shown:
X Projected Test Year Ended 12/31/14
_ Prior Year Ended 12/31/13
_ Historical Year Ended 12/31/12
Witness: S. D. Ritenour, R. J. Alexander, M. L. Burroughs, R. W. Grove

III. OVERVIEW OF THE FUEL/INTERCHANGE PROCESS

Description

The Fuel and Interchange Budgets are an integral part of Gulf's operating budget and the budgets of each of the other Operating Companies within the Southern electric system. Data provided by the fuel and interchange forecast includes unit capacity factors, unit performance, pool interchange, off-system sales, and fuel expenses.

The Interchange Budget is produced using PROSYM, a computer model used to simulate the economic dispatch of the Southern electric system. Inputs to the model are provided by the Operating Companies and include unit data, loads and sales information. In addition, marginal fuel prices and fuel cost data are provided by FUELPRO, a fuel optimization model that determines a least cost fuel purchase plan based on fuel burn, inventory, quality, transportation and emission constraints. The development of fuel costs for the Energy Budget is based on an iterative process. FUELPRO determines marginal prices for every fossil unit on the Southern electric system, then PROSYM determines the burn by unit based on the marginal costs. The burns are then input to FUELPRO and optimized fuel costs are provided back to PROSYM. A Fuel & Interchange Budget process flowchart is shown on page 7 of this schedule.

Once the budgets are complete, the results are provided to Corporate Planning to be incorporated into the operating budget.

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: If a projected test year is used, provide a brief description of each method or model used in the forecasting process. Provide a flow chart which shows the position of each model in the forecasting process.

Type of Data Shown:
X Projected Test Year Ended 12/31/14
_ Prior Year Ended 12/31/13
_ Historical Year Ended 12/31/12
Witness: S. D. Ritenour, R. J. Alexander, M. L. Burroughs, R. W. Grove

The following is a brief description of the models utilized in the forecast:

Fuel Cost Model, FUELPRO

FUELPRO is a linear optimization model that determines a least fuel cost solution allowing for a variety of constraints related to each of the fossil power plants in the Southern electric system. This includes such things as contract obligations, fuel quality, transportation and emissions constraints. The program receives an input of the burn requirements in mmBtu's for each unit at a plant, as well as the desired inventory levels, and the availabilities of fuel supplies from each applicable source. The price of each fuel commodity and its associated transportation costs are also provided as inputs to the fuel model, including any applicable escalation of pricing over time. With this data, the program calculates marginal prices to be used in economically dispatching the system and formulates and solves for the mimimum cost fuel mix to each plant (Fuel Budget).

Production Costing Model, PROSYM

Gulf Power Company and the Southern electric system utilize PROSYM, a chronological modeling system, to project future fuel requirements and system production costs. PROSYM is a complete electric utility/regional pool analysis and accounting system. One of the principal purposes of PROSYM is to provide an economical dispatch of all the fossil fuel plants within the Southern electric system based on marginal prices provided by FUELPRO plus other variable operation costs. PROSYM is designed for performing planning and operational studies, and because of its chronological structure, the model accommodates detailed investigations of operations of electric utilities with power pools such as the Southern electric system pool.

The basic PROSYM inputs include data related to generating units, marginal prices, fuel costs, demand and energy, and system operating characteristics. The basic outputs are energy produced and Btu requirements for each generating unit and the cost of generation (Interchange Budget) to the financial models.

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

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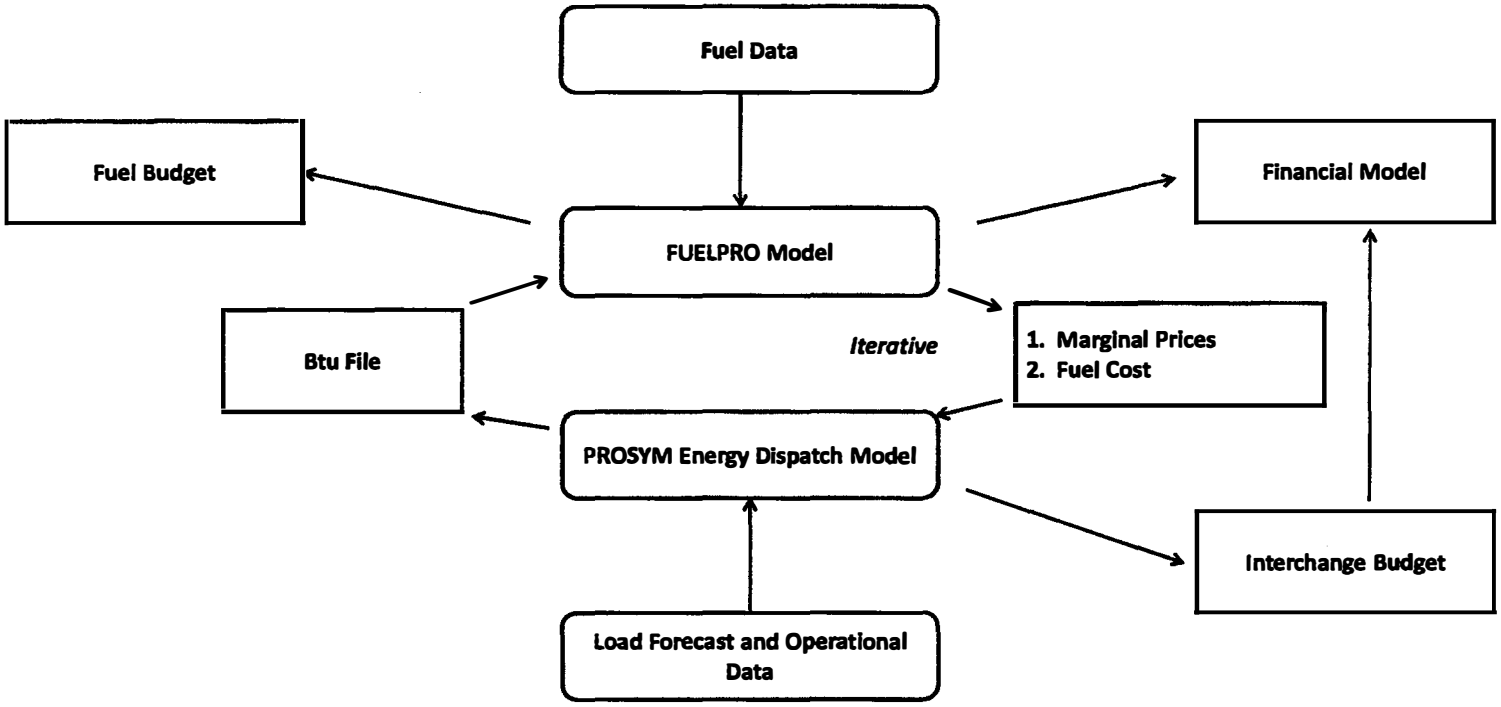
EXPLANATION: If a projected test year is used, provide a brief description of each method or model used in the forecasting process. Provide a flow chart which shows the position of each model in the forecasting process.

Type of Data Shown:
X Projected Test Year Ended 12/31/14
_ Prior Year Ended 12/31/13
_ Historical Year Ended 12/31/12
Witness: S. D. Ritenour, R. J. Alexander, M. L. Burroughs, R. W. Grove

FUEL & INTERCHANGE BUDGET PROCESS FLOWCHART



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Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: If a projected test year is used, provide a brief description of each method or model used in the forecasting process. Provide a flow chart which shows the position of each model in the forecasting process.

Type of Data Shown:
X Projected Test Year Ended 12/31/14
_ Prior Year Ended 12/31/13
_ Historical Year Ended 12/31/12
Witness: S. D. Ritenour, R. J. Alexander, M. L. Burroughs, R. W. Grove

IV. CAPITAL ADDITIONS BUDGET

A. Construction Expenditures

Gulf's construction requirements are determined through a detailed analysis of existing facilities and projections of customer growth, energy, demand, and patterns of energy usage. The construction budget is driven off of inputs obtained from the Customer, Energy, and Demand Budgets and is comprised of the following components:

(1) Major Generation and Production Plant Analysis. Utilizing inputs from the budgets mentioned above, the need for and timing of major generation additions necessary to maintain reliable service is projected. The resulting Generation Expansion Plan is coordinated with associated operating companies such that projected customer requirements are met, total system construction dollars are effectively utilized and economies of scale are realized. Other production plant additions are based on deterioration of existing facilities, operating experience, environmental requirements, and necessary expansions.

(2) Distribution Analysis. The results of monitoring circuit loads on the Gulf system and the inputs from the Customer, Energy, and Demand Budgets are utilized in studies which project the need for and timing of additions to Gulf's distribution system.

(3) Transmission Analysis. Combines the results of the major generation and distribution analysis and the inputs from the three budgets mentioned above to determine future transmission facility requirements.

(4) General Facilities Analysis. Involves combining periodic reviews of existing facilities, equipment, and their related costs and projections of future general facility requirements.

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COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: If a projected test year is used, provide a brief description of each method or model used in the forecasting process. Provide a flow chart which shows the position of each model in the forecasting process.

Type of Data Shown:
X Projected Test Year Ended 12/31/14
_ Prior Year Ended 12/31/13
_ Historical Year Ended 12/31/12
Witness: S. D. Ritenour, R. J. Alexander, M. L. Burroughs, R. W. Grove

These analyses are reviewed by the appropriate members of management and a construction plan for each function is established. The details of the construction plan are communicated to the affected departments and become the foundation for scheduling projects and budgeting the related expenditures. Each project, its justification, and related costs are summarized as Plant Expenditure items (PEs). The PEs are reviewed by the appropriate managers and officers. The PEs are then summarized by Corporate Planning and presented to executive management for their review and approval. Once approved by executive management, the Capital Additions Budget is presented to the Board of Directors for approval.

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B. Plant - In - Service, Retirements, Cost of Removal and Salvage

Each PE contains pertinent information such as the project's functional classification, starting date and completion date, expenditures, clearings to service, retirements, and cost of removal and salvage by month and year. The PE may contain one or more projects with varying completion dates. The monthly breakdown of expenditures, clearings to service, retirements, cost of removal and salvage for the budget year and the forecast years are input to the Financial Model which calculates the various plant balances on a monthly basis.

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: If a projected test year is used, provide a brief description of each method or model used in the forecasting process. Provide a flow chart which shows the position of each model in the forecasting process.

Type of Data Shown:
X Projected Test Year Ended 12/31/14
_ Prior Year Ended 12/31/13
_ Historical Year Ended 12/31/12
Witness: S. D. Ritenour, R. J. Alexander, M. L. Burroughs, R. W. Grove

V. OPERATIONS AND MAINTENANCE EXPENSES EXCLUDING FUEL AND PURCHASED POWER

The development of Gulf's Operations and Maintenance Budget (O&M), excluding direct fuel and purchased power, begins with the development of appropriate budget guidelines. The Budget Message that communicates the O&M guidelines to support Company goals is reviewed and approved by the Chief Financial Officer and is distributed to the planning units to aid them in developing and submitting their budget and forecast requests. Once the planning units have submitted their budget, Corporate Planning and Budgeting compile the data for review and approval by executive managment. Once the final budget has been approved by executive management, the Chief Financial Officer sends the final approved budget and forecast to executive management and all Planning Units.

Each Planning Unit monitors their budget to actual comparison using the accounting and reporting system. Explanations are required for quarterly variances of 10 percent or more that equal or exceed $25,000; or any variance that exceeds $500,000. The Planning Units also submit any year-end projections with their quarterly reports.

The Budgeting department is responsible for coordinating the O&M Budget process, providing the necessary information to the Chief Financial Officer and executive management for their review and approval to ensure business plans and goals are met. The O&M Budget reflects the Company's best expectations of the cost of providing service.

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: If a projected test year is used, provide a brief description of each method or model used in the forecasting process. Provide a flow chart which shows the position of each model in the forecasting process.

Type of Data Shown:
X Projected Test Year Ended 12/31/14
_ Prior Year Ended 12/31/13
_ Historical Year Ended 12/31/12
Witness: S. D. Ritenour, R. J. Alexander, M. L. Burroughs, R. W. Grove

VI. FINANCIAL MODEL

Gulf's Financial Model is a complex and detailed computer based model that closely simulates Gulf's actual financial/accounting practices.

Information contained in the approved budgets developed by Gulf's planning process (see page 2 of this schedule) is input to the model as follows:

(1) Energy Budget. The Energy Budget is interfaced with the Financial Model and is used in conjunction with the Fuel and Interchange Budgets in developing fuel revenues on the income statement. The Energy Budget is described in Section II of this schedule.

(2) Fuel Budget. The Fuel Budget is produced by the FUELPRO and PROSYM models as described in Section III of this schedule, which interface with the Financial Model. The Fuel Budget contains the projected fuel expense that is included on the Financial Model's income statement and the projected fuel stockpile amounts that are included on the balance sheet. The Fuel Budget also operates in conjunction with the Energy and Interchange Budgets in projecting the fuel revenues included on the income statement. Additionally, the Fuel Budget is used in deriving a portion of the Other Accounts Payable account contained on the balance sheet.

(3) Interchange Budget. The Interchange Budget is produced by the FUELPRO and PROSYM models as described in Section III of this schedule, which interface with the Financial Model. The Interchange Budget provides the non-territorial sales and purchased power transactions that appear on the model's income statement. In conjunction with the Energy and Fuel Budgets, the Interchange Budget is used to project the Fuel and Capacity Revenues on the income statement. The Interchange Budget is also used in calculating a portion of the Associated Companies Accounts Receivable, Associated Companies Accounts Payable and a portion of the Other Accounts Payable account contained on the balance sheet.

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: If a projected test year is used, provide a brief description of each method or model used in the forecasting process. Provide a flow chart which shows the position of each model in the forecasting process.

Type of Data Shown:
X Projected Test Year Ended 12/31/14
_ Prior Year Ended 12/31/13
_ Historical Year Ended 12/31/12
Witness: S. D. Ritenour, R. J. Alexander, M. L. Burroughs, R. W. Grove

(4) Revenue Budget. The Revenue Budget as described in Section II of this schedule, is contained on the income statement of the model and is used in calculating numerous other items on the income statement and balance sheet.

(5) Capital Additions Budget. The Capital Additions Budget is utilized in projecting the Plant-In-Service, Plant Held for Future Use, CWIP, Accumulated Depreciation, and Construction Related Accounts Payable accounts. The Capital Additions Budget is described in Section IV of this schedule.

(6) Operations and Maintenance Budget (excluding Direct Fuel and Purchased Power). The O&M Budget is directly input to the financial model's income statement and is utilized in deriving a portion of the Other Accounts Payable account on the balance sheet. The O&M Budget is described in Section V of this schedule.

Other inputs to the Financial Model such as miscellaneous balance sheet accounts and miscellaneous revenue and expense items are developed by the Corporate Planning Department using trend-line methodologies and expertise from other departments. Corporate Planning is the administrator of the model and is responsible for coordinating and implementing any necessary changes to the model's logic.

The Financial Model is constantly undergoing modifications and enhancements in response to the changing conditions in the utility industry. These adjustments enable the model to continue as an effective tool for use by management in planning and decision-making as well as providing information that is used for rate making purposes.

Schedule F-6 FORECASTING MODELS - SENSITIVITY OF OUTPUT TO CHANGES IN INPUT DATA Page 1 of 1

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: If a projected test year is used, for each sales forecasting model, give a quantified explanation of the impact of changes in the inputs to changes in outputs.

Type of Data Shown:
_X_ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
___ Historical Year Ended 12/31/12
Witness: R. J. Alexander

(1) Line No.	(2) Input Variable	(3) Percent Change (Input)	(4) Output Variable Affected	(5) Percent Change (Output)
1	RESIDENTIAL			
2				
3	Residential Customer Gains	+10%	Annual Residential kWh	0.1%
4	12-Month Average Real Residential Cents per kWh Increase Index	+10%	Annual Residential kWh	-6.1%
5	12-Month Average Real Residential Cents per kWh Decline Index	-10%	Annual Residential kWh	0.9%
6	Real Disposable Personal Income per Household	+10%	Annual Residential kWh	5.4%
7	Heating Degree Hours	+10%	Annual Residential kWh	1.2%
8	Cooling Degree Hours	+10%	Annual Residential kWh	3.2%
9	SMALL COMMERCIAL			
10				
11	Small Commercial Customer Gains	+10%	Annual Small Commercial kWh	0.1%
12	12-Month Average Real Commercial Cents per kWh	+10%	Annual Small Commercial kWh	-2.2%
13	Non-Manufacturing Employment	+10%	Annual Small Commercial kWh	4.5%
14	Heating Degree Hours	+10%	Annual Small Commercial kWh	0.5%
15	Cooling Degree Hours	+10%	Annual Small Commercial kWh	2.0%
16	LARGE COMMERCIAL			
17				
18	Large Commercial Customer Gains	+10%	Annual Large Commercial kWh	0.1%
19	12-Month Average Real Commercial Cents per kWh	+10%	Annual Large Commercial kWh	-1.7%
20	Non-Manufacturing Employment	+10%	Annual Large Commercial kWh	3.3%
21	Heating Degree Hours	+10%	Annual Large Commercial kWh	0.1%
22	Cooling Degree Hours	+10%	Annual Large Commercial kWh	1.7%

Supporting Schedules: Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of Data Shown:
___ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
_X_ Historical Years 1992 Through 1993
Witness: R. J. Alexander

FORECASTING MODEL: RESIDENTIAL ENERGY

(1) LINE NO.	(2) YEAR	(3) MONTH	(4) ResSales (OUTPUT)	(5) ResSales (INPUT)	(6) RealDisplnc (INPUT)	(7) ResPriceDec (INPUT)	(8) ResPriceInc (INPUT)	(9) Ivan (INPUT)	(10) Isaac (INPUT)	(11) JunJulAug08 (INPUT)
1	1992	NOV		27.623	55.639	8.556	9.154	0	0	0
2	1992	DEC	31.504	32.512	55.443	8.556	9.169	0	0	0
3	1993	JAN	29.295	31.730	54.993	8.556	9.172	0	0	0
4	1993	FEB	34.511	34.534	54.704	8.556	9.213	0	0	0
5	1993	MAR	33.015	34.353	54.797	8.556	9.244	0	0	0
6	1993	APR	29.016	28.261	55.110	8.556	9.257	0	0	0
7	1993	MAY	27.988	26.390	55.338	8.554	9.257	0	0	0
8	1993	JUN	40.270	38.857	55.280	8.554	9.262	0	0	0
9	1993	JUL	49.252	50.708	55.069	8.551	9.262	0	0	0
10	1993	AUG	53.432	53.958	54.948	8.549	9.262	0	0	0
11	1993	SEP	48.971	47.911	55.061	8.540	9.262	0	0	0
12	1993	OCT	38.745	38.282	55.267	8.529	9.262	0	0	0
13	1993	NOV	30.008	30.617	55.334	8.476	9.262	0	0	0
14	1993	DEC	31.966	32.458	55.131	8.422	9.262	0	0	0

VARIABLE	DESCRIPTION
ResSales	Billing Cycle Residential kWh per Customer per Billing Day
RealDisplnc	Real Disposable Personal Income Per Household ($000's)
ResPriceDec	12-Month Average of Real Residential Price Decline Index (cents per kWh)
ResPriceInc	12-Month Average of Real Residential Price Increase Index (cents per kWh)
Ivan	Binary Variable for Hurricane Ivan September 2004
Isaac	Binary Variable for Hurricane Isaac August-September 2012
JunJulAug08	Binary Variable for June-August 2008

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of Data Shown:
___ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
_X_ Historical Years 1994 Through 1995
Witness: R. J. Alexander

FORECASTING MODEL: RESIDENTIAL ENERGY

(1) LINE NO.	(2) YEAR	(3) MONTH	(4) ResSales (OUTPUT)	(5) ResSales (INPUT)	(6) RealDisplnc (INPUT)	(7) ResPriceDec (INPUT)	(8) ResPriceInc (INPUT)	(9) Ivan (INPUT)	(10) Isaac (INPUT)	(11) JunJulAug08 (INPUT)
1	1994	JAN	43.366	44.400	54.816	8.380	9.262	0	0	0
2	1994	FEB	38.794	39.011	54.657	8.302	9.262	0	0	0
3	1994	MAR	29.831	29.801	54.791	8.256	9.262	0	0	0
4	1994	APR	28.484	27.815	55.100	8.232	9.262	0	0	0
5	1994	MAY	32.228	31.856	55.367	8.228	9.262	0	0	0
6	1994	JUN	41.378	40.919	55.441	8.203	9.262	0	0	0
7	1994	JUL	46.884	46.852	55.392	8.194	9.262	0	0	0
8	1994	AUG	46.210	46.915	55.360	8.193	9.262	0	0	0
9	1994	SEP	45.091	45.360	55.450	8.193	9.265	0	0	0
10	1994	OCT	36.826	36.479	55.645	8.193	9.265	0	0	0
11	1994	NOV	27.196	27.511	55.894	8.193	9.307	0	0	0
12	1994	DEC	29.070	29.298	56.147	8.193	9.356	0	0	0
13	1995	JAN	35.001	35.737	56.348	8.193	9.403	0	0	0
14	1995	FEB	36.778	37.582	56.435	8.193	9.468	0	0	0
15	1995	MAR	30.133	30.923	56.394	8.193	9.503	0	0	0
16	1995	APR	27.893	27.494	56.299	8.193	9.532	0	0	0
17	1995	MAY	32.075	30.501	56.263	8.193	9.548	0	0	0
18	1995	JUN	43.967	45.354	56.356	8.193	9.568	0	0	0
19	1995	JUL	50.387	48.664	56.526	8.193	9.576	0	0	0
20	1995	AUG	51.870	52.465	56.678	8.193	9.588	0	0	0
21	1995	SEP	51.587	51.348	56.745	8.193	9.596	0	0	0
22	1995	OCT	40.416	39.622	56.773	8.193	9.605	0	0	0
23	1995	NOV	28.882	28.726	56.830	8.185	9.605	0	0	0
24	1995	DEC	32.313	32.429	56.964	8.178	9.605	0	0	0

VARIABLE	DESCRIPTION
ResSales	Billing Cycle Residential kWh per Customer per Billing Day
RealDisplnc	Real Disposable Personal Income Per Household ($000's)
ResPriceDec	12-Month Average of Real Residential Price Decline Index (cents per kWh)
ResPriceInc	12-Month Average of Real Residential Price Increase Index (cents per kWh)
Ivan	Binary Variable for Hurricane Ivan September 2004
Isaac	Binary Variable for Hurricane Isaac August-September 2012
JunJulAug08	Binary Variable for June-August 2008

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of Data Shown:
___ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
_X_ Historical Years 1996 Through 1997
Witness: R. J. Alexander

FORECASTING MODEL: RESIDENTIAL ENERGY

(1) LINE NO.	(2) YEAR	(3) MONTH	(4) ResSales (OUTPUT)	(5) ResSales (INPUT)	(6) RealDispInc (INPUT)	(7) ResPriceDec (INPUT)	(8) ResPriceInc (INPUT)	(9) Ivan (INPUT)	(10) Isaac (INPUT)	(11) JunJulAug08 (INPUT)
1	1996	JAN	43.518	44.219	57.147	8.169	9.605	0	0	0
2	1996	FEB	41.785	43.051	57.324	8.142	9.605	0	0	0
3	1996	MAR	35.083	34.883	57.464	8.120	9.605	0	0	0
4	1996	APR	29.446	30.326	57.578	8.097	9.605	0	0	0
5	1996	MAY	32.146	30.237	57.690	8.074	9.605	0	0	0
6	1996	JUN	45.613	44.167	57.812	8.061	9.605	0	0	0
7	1996	JUL	52.815	51.565	57.943	8.051	9.605	0	0	0
8	1996	AUG	52.248	51.386	58.077	8.038	9.605	0	0	0
9	1996	SEP	46.851	47.313	58.200	8.028	9.605	0	0	0
10	1996	OCT	37.561	37.314	58.293	8.019	9.605	0	0	0
11	1996	NOV	29.986	29.370	58.345	8.019	9.607	0	0	0
12	1996	DEC	31.437	31.664	58.344	8.015	9.607	0	0	0
13	1997	JAN	36.457	37.657	58.306	8.013	9.607	0	0	0
14	1997	FEB	36.752	34.022	58.258	8.011	9.607	0	0	0
15	1997	MAR	28.246	29.742	58.227	8.008	9.607	0	0	0
16	1997	APR	28.062	27.509	58.254	8.008	9.609	0	0	0
17	1997	MAY	29.601	27.802	58.391	7.991	9.609	0	0	0
18	1997	JUN	39.512	38.266	58.646	7.975	9.609	0	0	0
19	1997	JUL	49.904	49.588	58.921	7.961	9.609	0	0	0
20	1997	AUG	50.636	50.906	59.078	7.939	9.609	0	0	0
21	1997	SEP	49.324	50.851	59.047	7.914	9.609	0	0	0
22	1997	OCT	41.849	43.935	58.986	7.886	9.609	0	0	0
23	1997	NOV	31.119	31.844	59.110	7.835	9.609	0	0	0
24	1997	DEC	34.241	34.375	59.548	7.789	9.609	0	0	0

VARIABLE	DESCRIPTION
ResSales	Billing Cycle Residential kWh per Customer per Billing Day
RealDispInc	Real Disposable Personal Income Per Household ($000's)
ResPriceDec	12-Month Average of Real Residential Price Decline Index (cents per kWh)
ResPriceInc	12-Month Average of Real Residential Price Increase Index (cents per kWh)
Ivan	Binary Variable for Hurricane Ivan September 2004
Isaac	Binary Variable for Hurricane Isaac August-September 2012
JunJulAug08	Binary Variable for June-August 2008

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of Data Shown:
___ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
_X_ Historical Years 1998 Through 1999
Witness: R. J. Alexander

FORECASTING MODEL: RESIDENTIAL ENERGY

(1) LINE NO.	(2) YEAR	(3) MONTH	(4) ResSales (OUTPUT)	(5) ResSales (INPUT)	(6) RealDisplnc (INPUT)	(7) ResPriceDec (INPUT)	(8) ResPriceInc (INPUT)	(9) Ivan (INPUT)	(10) Isaac (INPUT)	(11) JunJulAug08 (INPUT)
1	1998	JAN	37.599	37.600	60.162	7.742	9.609	0	0	0
2	1998	FEB	36.973	36.952	60.688	7.714	9.609	0	0	0
3	1998	MAR	33.263	32.712	61.000	7.687	9.609	0	0	0
4	1998	APR	29.450	29.236	61.136	7.648	9.609	0	0	0
5	1998	MAY	33.588	32.367	61.174	7.579	9.609	0	0	0
6	1998	JUN	50.344	51.327	61.196	7.500	9.609	0	0	0
7	1998	JUL	57.156	56.794	61.215	7.417	9.609	0	0	0
8	1998	AUG	53.399	53.227	61.224	7.346	9.609	0	0	0
9	1998	SEP	49.627	47.541	61.226	7.281	9.609	0	0	0
10	1998	OCT	41.207	45.538	61.243	7.183	9.609	0	0	0
11	1998	NOV	31.893	30.329	61.305	7.183	9.612	0	0	0
12	1998	DEC	29.620	29.384	61.420	7.101	9.612	0	0	0
13	1999	JAN	40.010	38.169	61.568	7.055	9.612	0	0	0
14	1999	FEB	29.965	30.910	61.695	7.000	9.612	0	0	0
15	1999	MAR	32.154	30.588	61.784	6.959	9.612	0	0	0
16	1999	APR	29.930	29.849	61.864	6.911	9.612	0	0	0
17	1999	MAY	33.991	33.905	61.984	6.902	9.612	0	0	0
18	1999	JUN	43.292	43.661	62.159	6.895	9.612	0	0	0
19	1999	JUL	51.124	52.044	62.336	6.895	9.618	0	0	0
20	1999	AUG	56.461	56.174	62.433	6.895	9.621	0	0	0
21	1999	SEP	50.771	51.103	62.419	6.889	9.621	0	0	0
22	1999	OCT	39.277	38.350	62.431	6.889	9.655	0	0	0
23	1999	NOV	30.689	29.979	62.654	6.831	9.655	0	0	0
24	1999	DEC	32.109	32.014	63.181	6.831	9.668	0	0	0

VARIABLE	DESCRIPTION
ResSales	Billing Cycle Residential kWh per Customer per Billing Day
RealDisplnc	Real Disposable Personal Income Per Household ($000's)
ResPriceDec	12-Month Average of Real Residential Price Decline Index (cents per kWh)
ResPriceInc	12-Month Average of Real Residential Price Increase Index (cents per kWh)
Ivan	Binary Variable for Hurricane Ivan September 2004
Isaac	Binary Variable for Hurricane Isaac August-September 2012
JunJulAug08	Binary Variable for June-August 2008

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of Data Shown:
___ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
_X_ Historical Years 2000 Through 2001
Witness: R. J. Alexander

FORECASTING MODEL: RESIDENTIAL ENERGY

(1) LINE NO.	(2) YEAR	(3) MONTH	(4) ResSales (OUTPUT)	(5) ResSales (INPUT)	(6) RealDisplnc (INPUT)	(7) ResPriceDec (INPUT)	(8) ResPriceInc (INPUT)	(9) Ivan (INPUT)	(10) Isaac (INPUT)	(11) JunJulAug08 (INPUT)
1	2000	JAN	37.768	36.370	63.821	6.810	9.668	0	0	0
2	2000	FEB	39.984	40.064	64.268	6.810	9.687	0	0	0
3	2000	MAR	30.049	28.426	64.365	6.804	9.687	0	0	0
4	2000	APR	29.151	28.620	64.227	6.804	9.708	0	0	0
5	2000	MAY	33.317	33.351	64.059	6.804	9.732	0	0	0
6	2000	JUN	47.895	48.775	64.013	6.804	9.745	0	0	0
7	2000	JUL	56.655	56.383	64.046	6.804	9.755	0	0	0
8	2000	AUG	56.632	55.441	64.060	6.804	9.766	0	0	0
9	2000	SEP	50.263	51.217	63.993	6.804	9.779	0	0	0
10	2000	OCT	37.865	37.315	63.911	6.804	9.790	0	0	0
11	2000	NOV	32.529	31.983	63.919	6.804	9.805	0	0	0
12	2000	DEC	38.229	38.046	64.062	6.804	9.818	0	0	0
13	2001	JAN	51.521	51.173	64.207	6.804	9.825	0	0	0
14	2001	FEB	38.412	38.376	64.174	6.762	9.825	0	0	0
15	2001	MAR	30.918	30.104	63.902	6.742	9.825	0	0	0
16	2001	APR	30.752	31.879	63.634	6.711	9.825	0	0	0
17	2001	MAY	33.595	33.642	63.752	6.675	9.825	0	0	0
18	2001	JUN	45.906	44.889	64.425	6.651	9.825	0	0	0
19	2001	JUL	50.308	51.065	65.237	6.630	9.825	0	0	0
20	2001	AUG	52.558	53.917	65.582	6.609	9.825	0	0	0
21	2001	SEP	48.640	47.344	65.121	6.590	9.825	0	0	0
22	2001	OCT	36.274	35.210	64.375	6.573	9.825	0	0	0
23	2001	NOV	30.341	29.700	64.108	6.554	9.825	0	0	0
24	2001	DEC	30.923	30.020	64.790	6.536	9.825	0	0	0

VARIABLE	DESCRIPTION
ResSales	Billing Cycle Residential kWh per Customer per Billing Day
RealDisplnc	Real Disposable Personal Income Per Household ($000's)
ResPriceDec	12-Month Average of Real Residential Price Decline Index (cents per kWh)
ResPriceInc	12-Month Average of Real Residential Price Increase Index (cents per kWh)
Ivan	Binary Variable for Hurricane Ivan September 2004
Isaac	Binary Variable for Hurricane Isaac August-September 2012
JunJulAug08	Binary Variable for June-August 2008

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of Data Shown:
___ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
_X_ Historical Years 2002 Through 2003
Witness: R. J. Alexander

FORECASTING MODEL: RESIDENTIAL ENERGY

(1) LINE NO.	(2) YEAR	(3) MONTH	(4) ResSales (OUTPUT)	(5) ResSales (INPUT)	(6) RealDispInc (INPUT)	(7) ResPriceDec (INPUT)	(8) ResPriceInc (INPUT)	(9) Ivan (INPUT)	(10) Isaac (INPUT)	(11) JunJulAug08 (INPUT)
1	2002	JAN	43.830	43.992	66.014	6.534	9.825	0	0	0
2	2002	FEB	37.036	36.450	67.011	6.534	9.844	0	0	0
3	2002	MAR	38.213	37.134	67.375	6.534	9.860	0	0	0
4	2002	APR	30.625	31.561	67.259	6.531	9.860	0	0	0
5	2002	MAY	39.409	41.099	66.999	6.531	9.875	0	0	0
6	2002	JUN	46.079	44.625	66.881	6.530	9.875	0	0	0
7	2002	JUL	50.892	53.372	66.944	6.530	9.948	0	0	0
8	2002	AUG	54.090	54.182	67.138	6.530	10.025	0	0	0
9	2002	SEP	51.035	50.576	67.408	6.530	10.102	0	0	0
10	2002	OCT	44.240	45.755	67.680	6.530	10.175	0	0	0
11	2002	NOV	32.299	32.410	67.884	6.530	10.238	0	0	0
12	2002	DEC	37.545	36.868	67.971	6.530	10.319	0	0	0
13	2003	JAN	44.370	44.780	68.011	6.530	10.382	0	0	0
14	2003	FEB	42.822	42.104	68.093	6.530	10.456	0	0	0
15	2003	MAR	30.490	31.421	68.290	6.530	10.521	0	0	0
16	2003	APR	30.790	30.128	68.624	6.530	10.617	0	0	0
17	2003	MAY	36.787	38.759	69.096	6.530	10.701	0	0	0
18	2003	JUN	46.456	48.036	69.669	6.530	10.782	0	0	0
19	2003	JUL	49.875	50.224	70.227	6.530	10.796	0	0	0
20	2003	AUG	50.785	51.870	70.636	6.530	10.805	0	0	0
21	2003	SEP	49.288	50.019	70.805	6.530	10.815	0	0	0
22	2003	OCT	37.864	37.365	70.831	6.530	10.823	0	0	0
23	2003	NOV	31.228	31.601	70.853	6.530	10.845	0	0	0
24	2003	DEC	37.248	37.389	70.979	6.530	10.857	0	0	0

VARIABLE	DESCRIPTION
ResSales	Billing Cycle Residential kWh per Customer per Billing Day
RealDispInc	Real Disposable Personal Income Per Household ($000's)
ResPriceDec	12-Month Average of Real Residential Price Decline Index (cents per kWh)
ResPriceInc	12-Month Average of Real Residential Price Increase Index (cents per kWh)
Ivan	Binary Variable for Hurricane Ivan September 2004
Isaac	Binary Variable for Hurricane Isaac August-September 2012
JunJulAug08	Binary Variable for June-August 2008

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of Data Shown:
___ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
_X_ Historical Years 2004 Through 2005
Witness: R. J. Alexander

FORECASTING MODEL: RESIDENTIAL ENERGY

(1) LINE NO.	(2) YEAR	(3) MONTH	(4) ResSales (OUTPUT)	(5) ResSales (INPUT)	(6) RealDisplnc (INPUT)	(7) ResPriceDec (INPUT)	(8) ResPriceInc (INPUT)	(9) Ivan (INPUT)	(10) Isaac (INPUT)	(11) JunJulAug08 (INPUT)
1	2004	JAN	43.357	42.902	71.196	6.530	10.866	0	0	0
2	2004	FEB	41.894	42.709	71.453	6.530	10.877	0	0	0
3	2004	MAR	34.345	34.450	71.708	6.530	10.885	0	0	0
4	2004	APR	31.276	29.688	71.908	6.527	10.885	0	0	0
5	2004	MAY	32.819	33.871	71.994	6.527	10.891	0	0	0
6	2004	JUN	46.828	48.182	71.949	6.527	10.908	0	0	0
7	2004	JUL	52.503	54.305	71.889	6.527	10.911	0	0	0
8	2004	AUG	53.794	54.119	71.978	6.527	10.912	0	0	0
9	2004	SEP	38.935	39.475	72.289	6.526	10.912	1	0	0
10	2004	OCT	44.040	45.283	72.647	6.526	10.917	0	0	0
11	2004	NOV	33.808	34.811	72.807	6.526	10.917	0	0	0
12	2004	DEC	34.729	34.784	72.622	6.509	10.917	0	0	0
13	2005	JAN	39.806	40.003	72.257	6.509	10.923	0	0	0
14	2005	FEB	37.958	38.168	71.989	6.509	10.947	0	0	0
15	2005	MAR	33.336	33.389	71.968	6.509	10.976	0	0	0
16	2005	APR	29.349	29.429	72.142	6.509	11.001	0	0	0
17	2005	MAY	31.641	32.014	72.375	6.509	11.046	0	0	0
18	2005	JUN	45.832	46.631	72.553	6.509	11.101	0	0	0
19	2005	JUL	53.520	53.169	72.649	6.509	11.146	0	0	0
20	2005	AUG	53.527	54.324	72.656	6.509	11.187	0	0	0
21	2005	SEP	53.305	55.466	72.612	6.509	11.226	0	0	0
22	2005	OCT	47.469	45.885	72.639	6.509	11.258	0	0	0
23	2005	NOV	31.491	32.640	72.888	6.509	11.283	0	0	0
24	2005	DEC	35.403	36.472	73.433	6.509	11.338	0	0	0

VARIABLE	DESCRIPTION
ResSales	Billing Cycle Residential kWh per Customer per Billing Day
RealDisplnc	Real Disposable Personal Income Per Household ($000's)
ResPriceDec	12-Month Average of Real Residential Price Decline Index (cents per kWh)
ResPriceInc	12-Month Average of Real Residential Price Increase Index (cents per kWh)
Ivan	Binary Variable for Hurricane Ivan September 2004
Isaac	Binary Variable for Hurricane Isaac August-September 2012
JunJulAug08	Binary Variable for June-August 2008

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of Data Shown:
___ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
_X_ Historical Years 2006 Through 2007
Witness: R. J. Alexander

FORECASTING MODEL: RESIDENTIAL ENERGY

(1) LINE NO.	(2) YEAR	(3) MONTH	(4) ResSales (OUTPUT)	(5) ResSales (INPUT)	(6) RealDisplnc (INPUT)	(7) ResPriceDec (INPUT)	(8) ResPriceInc (INPUT)	(9) Ivan (INPUT)	(10) Isaac (INPUT)	(11) JunJulAug08 (INPUT)
1	2006	JAN	37.237	38.032	74.127	6.509	11.379	0	0	0
2	2006	FEB	35.499	35.046	74.706	6.509	11.422	0	0	0
3	2006	MAR	32.430	31.661	75.056	6.509	11.466	0	0	0
4	2006	APR	32.112	31.504	75.216	6.509	11.509	0	0	0
5	2006	MAY	36.241	37.187	75.273	6.509	11.519	0	0	0
6	2006	JUN	49.484	49.195	75.311	6.501	11.519	0	0	0
7	2006	JUL	56.910	57.219	75.363	6.501	11.530	0	0	0
8	2006	AUG	54.990	56.483	75.443	6.501	11.537	0	0	0
9	2006	SEP	51.307	51.987	75.544	6.501	11.550	0	0	0
10	2006	OCT	41.716	40.035	75.639	6.501	11.569	0	0	0
11	2006	NOV	31.197	31.581	75.675	6.501	11.600	0	0	0
12	2006	DEC	35.930	35.638	75.630	6.501	11.619	0	0	0
13	2007	JAN	34.880	35.934	75.542	6.501	11.636	0	0	0
14	2007	FEB	42.940	40.272	75.471	6.501	11.695	0	0	0
15	2007	MAR	32.488	32.641	75.463	6.501	11.731	0	0	0
16	2007	APR	30.752	30.418	75.526	6.501	11.777	0	0	0
17	2007	MAY	34.776	35.143	75.674	6.501	11.832	0	0	0
18	2007	JUN	44.614	44.168	75.900	6.501	11.894	0	0	0
19	2007	JUL	52.924	53.254	76.166	6.501	11.957	0	0	0
20	2007	AUG	56.543	56.427	76.428	6.501	12.018	0	0	0
21	2007	SEP	52.683	51.987	76.633	6.501	12.076	0	0	0
22	2007	OCT	43.667	43.437	76.781	6.501	12.132	0	0	0
23	2007	NOV	30.703	30.120	76.862	6.501	12.182	0	0	0
24	2007	DEC	31.272	31.051	76.918	6.501	12.242	0	0	0

VARIABLE	DESCRIPTION
ResSales	Billing Cycle Residential kWh per Customer per Billing Day
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Ivan	Binary Variable for Hurricane Ivan September 2004
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Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

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Type of Data Shown:
___ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
_X_ Historical Years 2008 Through 2009
Witness: R. J. Alexander

FORECASTING MODEL: RESIDENTIAL ENERGY

(1) LINE NO.	(2) YEAR	(3) MONTH	(4) ResSales (OUTPUT)	(5) ResSales (INPUT)	(6) RealDispInc (INPUT)	(7) ResPriceDec (INPUT)	(8) ResPriceInc (INPUT)	(9) Ivan (INPUT)	(10) Isaac (INPUT)	(11) JunJulAug08 (INPUT)
1	2008	JAN	38.666	37.890	77.123	6.501	12.314	0	0	0
2	2008	FEB	38.067	37.708	77.658	6.480	12.314	0	0	0
3	2008	MAR	33.028	31.496	78.590	6.480	12.314	0	0	0
4	2008	APR	29.608	29.572	79.550	6.476	12.314	0	0	0
5	2008	MAY	34.146	32.241	79.986	6.468	12.314	0	0	0
6	2008	JUN	45.759	46.338	79.576	6.463	12.314	0	0	1
7	2008	JUL	51.254	50.886	78.600	6.444	12.314	0	0	1
8	2008	AUG	52.922	50.844	77.517	6.431	12.314	0	0	1
9	2008	SEP	50.300	48.451	76.711	6.420	12.314	0	0	0
10	2008	OCT	37.373	36.989	76.120	6.420	12.386	0	0	0
11	2008	NOV	29.737	30.011	75.587	6.420	12.467	0	0	0
12	2008	DEC	33.987	33.761	75.020	6.420	12.548	0	0	0
13	2009	JAN	33.994	33.509	74.538	6.420	12.614	0	0	0
14	2009	FEB	38.827	38.010	74.335	6.420	12.775	0	0	0
15	2009	MAR	31.136	31.838	74.480	6.420	12.922	0	0	0
16	2009	APR	26.717	27.629	74.802	6.420	13.091	0	0	0
17	2009	MAY	32.866	33.057	75.017	6.420	13.258	0	0	0
18	2009	JUN	44.100	44.859	74.947	6.420	13.412	0	0	0
19	2009	JUL	53.882	54.282	74.723	6.420	13.579	0	0	0
20	2009	AUG	49.216	50.304	74.586	6.420	13.718	0	0	0
21	2009	SEP	43.555	43.172	74.705	6.420	13.865	0	0	0
22	2009	OCT	40.362	41.353	75.032	6.420	13.937	0	0	0
23	2009	NOV	28.389	28.665	75.448	6.420	13.991	0	0	0
24	2009	DEC	31.743	32.552	75.860	6.420	14.049	0	0	0

VARIABLE	DESCRIPTION
ResSales	Billing Cycle Residential kWh per Customer per Billing Day
RealDispInc	Real Disposable Personal Income Per Household ($000's)
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Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

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Type of Data Shown:
___ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
_X_ Historical Years 2010 Through 2011
Witness: R. J. Alexander

FORECASTING MODEL: RESIDENTIAL ENERGY

(1) LINE NO.	(2) YEAR	(3) MONTH	(4) ResSales (OUTPUT)	(5) ResSales (INPUT)	(6) RealDisplnc (INPUT)	(7) ResPriceDec (INPUT)	(8) ResPriceInc (INPUT)	(9) Ivan (INPUT)	(10) Isaac (INPUT)	(11) JunJulAug08 (INPUT)
1	2010	JAN	46.684	45.956	76.232	6.420	14.109	0	0	0
2	2010	FEB	41.917	42.724	76.520	6.405	14.109	0	0	0
3	2010	MAR	38.224	39.436	76.736	6.403	14.109	0	0	0
4	2010	APR	27.687	27.424	76.887	6.376	14.109	0	0	0
5	2010	MAY	31.208	32.534	76.988	6.376	14.114	0	0	0
6	2010	JUN	45.967	46.194	77.048	6.376	14.126	0	0	0
7	2010	JUL	52.556	51.585	77.077	6.375	14.126	0	0	0
8	2010	AUG	55.970	54.331	77.079	6.375	14.154	0	0	0
9	2010	SEP	47.846	48.968	77.063	6.375	14.168	0	0	0
10	2010	OCT	38.740	36.959	77.047	6.375	14.179	0	0	0
11	2010	NOV	28.234	29.098	77.057	6.375	14.209	0	0	0
12	2010	DEC	35.162	35.039	77.104	6.375	14.222	0	0	0
13	2011	JAN	43.382	43.539	77.195	6.375	14.231	0	0	0
14	2011	FEB	40.845	42.618	77.312	6.338	14.231	0	0	0
15	2011	MAR	29.839	29.156	77.447	6.297	14.231	0	0	0
16	2011	APR	28.542	28.812	77.552	6.281	14.231	0	0	0
17	2011	MAY	32.923	33.697	77.556	6.235	14.231	0	0	0
18	2011	JUN	47.150	46.795	77.431	6.178	14.231	0	0	0
19	2011	JUL	53.984	52.293	77.270	6.132	14.231	0	0	0
20	2011	AUG	53.523	52.582	77.193	6.086	14.231	0	0	0
21	2011	SEP	47.183	46.080	77.276	6.044	14.231	0	0	0
22	2011	OCT	33.949	34.380	77.425	6.011	14.231	0	0	0
23	2011	NOV	27.860	26.981	77.496	5.992	14.231	0	0	0
24	2011	DEC	30.071	30.291	77.393	5.987	14.231	0	0	0

VARIABLE	DESCRIPTION
ResSales	Billing Cycle Residential kWh per Customer per Billing Day
RealDisplnc	Real Disposable Personal Income Per Household ($000's)
ResPriceDec	12-Month Average of Real Residential Price Decline Index (cents per kWh)
ResPriceInc	12-Month Average of Real Residential Price Increase Index (cents per kWh)
Ivan	Binary Variable for Hurricane Ivan September 2004
Isaac	Binary Variable for Hurricane Isaac August-September 2012
JunJulAug08	Binary Variable for June-August 2008

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of Data Shown:
___ Projected Test Year Ended 12/31/14
_X_ Prior Year Ended 12/31/13
_X_ Historical Year 2012
Witness: R. J. Alexander

FORECASTING MODEL: RESIDENTIAL ENERGY

(1) LINE NO.	(2) YEAR	(3) MONTH	(4) ResSales (OUTPUT)	(5) ResSales (INPUT)	(6) RealDispInc (INPUT)	(7) ResPriceDec (INPUT)	(8) ResPriceInc (INPUT)	(9) Ivan (INPUT)	(10) Isaac (INPUT)	(11) JunJulAug08 (INPUT)
1	2012	JAN	30.866	30.927	77.135	5.987	14.233	0	0	0
2	2012	FEB	28.683	30.417	76.810	5.987	14.254	0	0	0
3	2012	MAR	27.478	28.353	76.479	5.987	14.311	0	0	0
4	2012	APR	28.473	29.840	76.197	5.969	14.311	0	0	0
5	2012	MAY	33.982	33.207	76.039	5.963	14.311	0	0	0
6	2012	JUN	45.328	43.811	76.045	5.963	14.326	0	0	0
7	2012	JUL	49.045	48.549	76.174	5.963	14.332	0	0	0
8	2012	AUG	48.353	48.125	76.362	5.899	14.332	0	1	0
9	2012	SEP	44.043	43.806	76.537	5.838	14.332	0	1	0
10	2012	OCT	36.779	35.945	76.619	5.765	14.332	0	0	0
11	2012	NOV	28.062		76.527	5.667	14.332	0	0	0
12	2012	DEC	31.237		76.228	5.571	14.332	0	0	0
13	2013	JAN	37.600		75.848	5.473	14.332	0	0	0
14	2013	FEB	36.053		75.573	5.395	14.332	0	0	0
15	2013	MAR	30.293		75.501	5.278	14.332	0	0	0
16	2013	APR	27.654		75.568	5.218	14.332	0	0	0
17	2013	MAY	31.628		75.667	5.151	14.332	0	0	0
18	2013	JUN	43.640		75.713	5.072	14.332	0	0	0
19	2013	JUL	50.897		75.732	5.001	14.332	0	0	0
20	2013	AUG	51.561		75.780	4.993	14.332	0	0	0
21	2013	SEP	47.574		75.892	4.985	14.332	0	0	0
22	2013	OCT	38.279		76.045	4.985	14.339	0	0	0
23	2013	NOV	28.888		76.193	4.985	14.351	0	0	0
24	2013	DEC	31.841		76.306	4.985	14.351	0	0	0

VARIABLE	DESCRIPTION
ResSales	Billing Cycle Residential kWh per Customer per Billing Day
RealDispInc	Real Disposable Personal Income Per Household ($000's)
ResPriceDec	12-Month Average of Real Residential Price Decline Index (cents per kWh)
ResPriceInc	12-Month Average of Real Residential Price Increase Index (cents per kWh)
Ivan	Binary Variable for Hurricane Ivan September 2004
Isaac	Binary Variable for Hurricane Isaac August-September 2012
JunJulAug08	Binary Variable for June-August 2008

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of Data Shown:
_X_ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
___ Historical Year 2012
Witness: R. J. Alexander

FORECASTING MODEL: RESIDENTIAL ENERGY

(1) LINE NO.	(2) YEAR	(3) MONTH	(4) ResSales (OUTPUT)	(5) ResSales (INPUT)	(6) RealDisplnc (INPUT)	(7) ResPriceDec (INPUT)	(8) ResPriceInc (INPUT)	(9) Ivan (INPUT)	(10) Isaac (INPUT)	(11) JunJulAug08 (INPUT)
1	2014	JAN	38.140		76.396	4.985	14.355	0	0	0
2	2014	FEB	36.472		76.480	4.985	14.427	0	0	0
3	2014	MAR	30.543		76.585	4.985	14.500	0	0	0
4	2014	APR	27.755		76.716	4.985	14.575	0	0	0
5	2014	MAY	31.576		76.869	4.985	14.651	0	0	0
6	2014	JUN	43.450		77.041	4.985	14.725	0	0	0
7	2014	JUL	50.587		77.217	4.985	14.797	0	0	0
8	2014	AUG	51.167		77.382	4.985	14.868	0	0	0
9	2014	SEP	47.073		77.521	4.985	14.939	0	0	0
10	2014	OCT	37.674		77.658	4.985	15.012	0	0	0
11	2014	NOV	28.188		77.806	4.985	15.086	0	0	0
12	2014	DEC	31.041		77.985	4.985	15.162	0	0	0

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VARIABLE	DESCRIPTION
ResSales	Billing Cycle Residential kWh per Customer per Billing Day
RealDisplnc	Real Disposable Personal Income Per Household ($000's)
ResPriceDec	12-Month Average of Real Residential Price Decline Index (cents per kWh)
ResPriceInc	12-Month Average of Real Residential Price Increase Index (cents per kWh)
Ivan	Binary Variable for Hurricane Ivan September 2004
Isaac	Binary Variable for Hurricane Isaac August-September 2012
JunJulAug08	Binary Variable for June-August 2008

Supporting Schedules: Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of Data Shown:
___ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
_X_ Historical Years 1992 Through 1993
Witness: R. J. Alexander

FORECASTING MODEL: RESIDENTIAL ENERGY

(1) LINE NO.	(2) YEAR	(3) MONTH	(4) CDHBD_03 (INPUT)	(5) CDHBD_04 (INPUT)	(6) CDHBD_05 (INPUT)	(7) CDHBD_06 (INPUT)	(8) CDHBD_07 (INPUT)	(9) CDHBD_08 (INPUT)	(10) CDHBD_09 (INPUT)	(11) CDHBD_10 (INPUT)	(12) CDHBD_11 (INPUT)	(13) CDHBD_12 (INPUT)
1	1992	NOV	0	0	0	0	0	0	0	0	69	0
2	1992	DEC	0	0	0	0	0	0	0	0	0	15
3	1993	JAN	0	0	0	0	0	0	0	0	0	0
4	1993	FEB	0	0	0	0	0	0	0	0	0	0
5	1993	MAR	8	0	0	0	0	0	0	0	0	0
6	1993	APR	0	31	0	0	0	0	0	0	0	0
7	1993	MAY	0	0	86	0	0	0	0	0	0	0
8	1993	JUN	0	0	0	238	0	0	0	0	0	0
9	1993	JUL	0	0	0	0	343	0	0	0	0	0
10	1993	AUG	0	0	0	0	0	375	0	0	0	0
11	1993	SEP	0	0	0	0	0	0	337	0	0	0
12	1993	OCT	0	0	0	0	0	0	0	215	0	0
13	1993	NOV	0	0	0	0	0	0	0	0	78	0
14	1993	DEC	0	0	0	0	0	0	0	0	0	21

VARIABLE	DESCRIPTION
CDHBD_XX	Billing Cycle Residential Cooling Degree Hours per Billing Day for Month XX (03=March, etc.)

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of Data Shown:
___ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
_X_ Historical Years 1994 Through 1995
Witness: R. J. Alexander

FORECASTING MODEL: RESIDENTIAL ENERGY

(1) LINE NO.	(2) YEAR	(3) MONTH	(4) CDHBD_03 (INPUT)	(5) CDHBD_04 (INPUT)	(6) CDHBD_05 (INPUT)	(7) CDHBD_06 (INPUT)	(8) CDHBD_07 (INPUT)	(9) CDHBD_08 (INPUT)	(10) CDHBD_09 (INPUT)	(11) CDHBD_10 (INPUT)	(12) CDHBD_11 (INPUT)	(13) CDHBD_12 (INPUT)
1	1994	JAN	0	0	0	0	0	0	0	0	0	0
2	1994	FEB	0	0	0	0	0	0	0	0	0	0
3	1994	MAR	21	0	0	0	0	0	0	0	0	0
4	1994	APR	0	54	0	0	0	0	0	0	0	0
5	1994	MAY	0	0	147	0	0	0	0	0	0	0
6	1994	JUN	0	0	0	243	0	0	0	0	0	0
7	1994	JUL	0	0	0	0	303	0	0	0	0	0
8	1994	AUG	0	0	0	0	0	289	0	0	0	0
9	1994	SEP	0	0	0	0	0	0	285	0	0	0
10	1994	OCT	0	0	0	0	0	0	0	180	0	0
11	1994	NOV	0	0	0	0	0	0	0	0	77	0
12	1994	DEC	0	0	0	0	0	0	0	0	0	35
13	1995	JAN	0	0	0	0	0	0	0	0	0	0
14	1995	FEB	0	0	0	0	0	0	0	0	0	0
15	1995	MAR	14	0	0	0	0	0	0	0	0	0
16	1995	APR	0	52	0	0	0	0	0	0	0	0
17	1995	MAY	0	0	143	0	0	0	0	0	0	0
18	1995	JUN	0	0	0	283	0	0	0	0	0	0
19	1995	JUL	0	0	0	0	340	0	0	0	0	0
20	1995	AUG	0	0	0	0	0	364	0	0	0	0
21	1995	SEP	0	0	0	0	0	0	372	0	0	0
22	1995	OCT	0	0	0	0	0	0	0	232	0	0
23	1995	NOV	0	0	0	0	0	0	0	0	79	0
24	1995	DEC	0	0	0	0	0	0	0	0	0	21

VARIABLE	DESCRIPTION
CDHBD_XX	Billing Cycle Residential Cooling Degree Hours per Billing Day for Month XX (03=March, etc.)

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of Data Shown:
___ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
_X_ Historical Years 1996 Through 1997
Witness: R. J. Alexander

FORECASTING MODEL: RESIDENTIAL ENERGY

(1) LINE NO.	(2) YEAR	(3) MONTH	(4) CDHBD_03 (INPUT)	(5) CDHBD_04 (INPUT)	(6) CDHBD_05 (INPUT)	(7) CDHBD_06 (INPUT)	(8) CDHBD_07 (INPUT)	(9) CDHBD_08 (INPUT)	(10) CDHBD_09 (INPUT)	(11) CDHBD_10 (INPUT)	(12) CDHBD_11 (INPUT)	(13) CDHBD_12 (INPUT)
1	1996	JAN	0	0	0	0	0	0	0	0	0	0
2	1996	FEB	0	0	0	0	0	0	0	0	0	0
3	1996	MAR	21	0	0	0	0	0	0	0	0	0
4	1996	APR	0	22	0	0	0	0	0	0	0	0
5	1996	MAY	0	0	133	0	0	0	0	0	0	0
6	1996	JUN	0	0	0	298	0	0	0	0	0	0
7	1996	JUL	0	0	0	0	379	0	0	0	0	0
8	1996	AUG	0	0	0	0	0	367	0	0	0	0
9	1996	SEP	0	0	0	0	0	0	316	0	0	0
10	1996	OCT	0	0	0	0	0	0	0	190	0	0
11	1996	NOV	0	0	0	0	0	0	0	0	94	0
12	1996	DEC	0	0	0	0	0	0	0	0	0	31
13	1997	JAN	0	0	0	0	0	0	0	0	0	0
14	1997	FEB	0	0	0	0	0	0	0	0	0	0
15	1997	MAR	46	0	0	0	0	0	0	0	0	0
16	1997	APR	0	65	0	0	0	0	0	0	0	0
17	1997	MAY	0	0	102	0	0	0	0	0	0	0
18	1997	JUN	0	0	0	221	0	0	0	0	0	0
19	1997	JUL	0	0	0	0	340	0	0	0	0	0
20	1997	AUG	0	0	0	0	0	339	0	0	0	0
21	1997	SEP	0	0	0	0	0	0	335	0	0	0
22	1997	OCT	0	0	0	0	0	0	0	231	0	0
23	1997	NOV	0	0	0	0	0	0	0	0	50	0
24	1997	DEC	0	0	0	0	0	0	0	0	0	8

VARIABLE	DESCRIPTION
CDHBD_XX	Billing Cycle Residential Cooling Degree Hours per Billing Day for Month XX (03=March, etc.)

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of Data Shown:
___ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
_X_ Historical Years 1998 Through 1999
Witness: R. J. Alexander

FORECASTING MODEL: RESIDENTIAL ENERGY

(1) LINE NO.	(2) YEAR	(3) MONTH	(4) CDHBD_03 (INPUT)	(5) CDHBD_04 (INPUT)	(6) CDHBD_05 (INPUT)	(7) CDHBD_06 (INPUT)	(8) CDHBD_07 (INPUT)	(9) CDHBD_08 (INPUT)	(10) CDHBD_09 (INPUT)	(11) CDHBD_10 (INPUT)	(12) CDHBD_11 (INPUT)	(13) CDHBD_12 (INPUT)
1	1998	JAN	0	0	0	0	0	0	0	0	0	0
2	1998	FEB	0	0	0	0	0	0	0	0	0	0
3	1998	MAR	7	0	0	0	0	0	0	0	0	0
4	1998	APR	0	44	0	0	0	0	0	0	0	0
5	1998	MAY	0	0	145	0	0	0	0	0	0	0
6	1998	JUN	0	0	0	341	0	0	0	0	0	0
7	1998	JUL	0	0	0	0	403	0	0	0	0	0
8	1998	AUG	0	0	0	0	0	355	0	0	0	0
9	1998	SEP	0	0	0	0	0	0	326	0	0	0
10	1998	OCT	0	0	0	0	0	0	0	229	0	0
11	1998	NOV	0	0	0	0	0	0	0	0	93	0
12	1998	DEC	0	0	0	0	0	0	0	0	0	45
13	1999	JAN	0	0	0	0	0	0	0	0	0	0
14	1999	FEB	0	0	0	0	0	0	0	0	0	0
15	1999	MAR	13	0	0	0	0	0	0	0	0	0
16	1999	APR	0	65	0	0	0	0	0	0	0	0
17	1999	MAY	0	0	143	0	0	0	0	0	0	0
18	1999	JUN	0	0	0	239	0	0	0	0	0	0
19	1999	JUL	0	0	0	0	323	0	0	0	0	0
20	1999	AUG	0	0	0	0	0	378	0	0	0	0
21	1999	SEP	0	0	0	0	0	0	331	0	0	0
22	1999	OCT	0	0	0	0	0	0	0	185	0	0
23	1999	NOV	0	0	0	0	0	0	0	0	67	0
24	1999	DEC	0	0	0	0	0	0	0	0	0	17

VARIABLE	DESCRIPTION
CDHBD_XX	Billing Cycle Residential Cooling Degree Hours per Billing Day for Month XX (03=March, etc.)

Supporting Schedules: Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of Data Shown:
___ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
_X_ Historical Years 2000 Through 2001
Witness: R. J. Alexander

FORECASTING MODEL: RESIDENTIAL ENERGY

(1) LINE NO.	(2) YEAR	(3) MONTH	(4) CDHBD_03 (INPUT)	(5) CDHBD_04 (INPUT)	(6) CDHBD_05 (INPUT)	(7) CDHBD_06 (INPUT)	(8) CDHBD_07 (INPUT)	(9) CDHBD_08 (INPUT)	(10) CDHBD_09 (INPUT)	(11) CDHBD_10 (INPUT)	(12) CDHBD_11 (INPUT)	(13) CDHBD_12 (INPUT)
1	2000	JAN	0	0	0	0	0	0	0	0	0	0
2	2000	FEB	0	0	0	0	0	0	0	0	0	0
3	2000	MAR	29	0	0	0	0	0	0	0	0	0
4	2000	APR	0	52	0	0	0	0	0	0	0	0
5	2000	MAY	0	0	131	0	0	0	0	0	0	0
6	2000	JUN	0	0	0	293	0	0	0	0	0	0
7	2000	JUL	0	0	0	0	384	0	0	0	0	0
8	2000	AUG	0	0	0	0	0	382	0	0	0	0
9	2000	SEP	0	0	0	0	0	0	329	0	0	0
10	2000	OCT	0	0	0	0	0	0	0	164	0	0
11	2000	NOV	0	0	0	0	0	0	0	0	93	0
12	2000	DEC	0	0	0	0	0	0	0	0	0	11
13	2001	JAN	0	0	0	0	0	0	0	0	0	0
14	2001	FEB	0	0	0	0	0	0	0	0	0	0
15	2001	MAR	20	0	0	0	0	0	0	0	0	0
16	2001	APR	0	53	0	0	0	0	0	0	0	0
17	2001	MAY	0	0	124	0	0	0	0	0	0	0
18	2001	JUN	0	0	0	262	0	0	0	0	0	0
19	2001	JUL	0	0	0	0	311	0	0	0	0	0
20	2001	AUG	0	0	0	0	0	326	0	0	0	0
21	2001	SEP	0	0	0	0	0	0	289	0	0	0
22	2001	OCT	0	0	0	0	0	0	0	147	0	0
23	2001	NOV	0	0	0	0	0	0	0	0	71	0
24	2001	DEC	0	0	0	0	0	0	0	0	0	43

VARIABLE	DESCRIPTION
CDHBD_XX	Billing Cycle Residential Cooling Degree Hours per Billing Day for Month XX (03=March, etc.)

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of Data Shown:
___ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
_X_ Historical Years 2002 Through 2003
Witness: R. J. Alexander

FORECASTING MODEL: RESIDENTIAL ENERGY

(1) LINE NO.	(2) YEAR	(3) MONTH	(4) CDHBD_03 (INPUT)	(5) CDHBD_04 (INPUT)	(6) CDHBD_05 (INPUT)	(7) CDHBD_06 (INPUT)	(8) CDHBD_07 (INPUT)	(9) CDHBD_08 (INPUT)	(10) CDHBD_09 (INPUT)	(11) CDHBD_10 (INPUT)	(12) CDHBD_11 (INPUT)	(13) CDHBD_12 (INPUT)
1	2002	JAN	0	0	0	0	0	0	0	0	0	0
2	2002	FEB	0	0	0	0	0	0	0	0	0	0
3	2002	MAR	11	0	0	0	0	0	0	0	0	0
4	2002	APR	0	56	0	0	0	0	0	0	0	0
5	2002	MAY	0	0	197	0	0	0	0	0	0	0
6	2002	JUN	0	0	0	248	0	0	0	0	0	0
7	2002	JUL	0	0	0	0	313	0	0	0	0	0
8	2002	AUG	0	0	0	0	0	333	0	0	0	0
9	2002	SEP	0	0	0	0	0	0	319	0	0	0
10	2002	OCT	0	0	0	0	0	0	0	239	0	0
11	2002	NOV	0	0	0	0	0	0	0	0	73	0
12	2002	DEC	0	0	0	0	0	0	0	0	0	8
13	2003	JAN	0	0	0	0	0	0	0	0	0	0
14	2003	FEB	0	0	0	0	0	0	0	0	0	0
15	2003	MAR	18	0	0	0	0	0	0	0	0	0
16	2003	APR	0	57	0	0	0	0	0	0	0	0
17	2003	MAY	0	0	174	0	0	0	0	0	0	0
18	2003	JUN	0	0	0	261	0	0	0	0	0	0
19	2003	JUL	0	0	0	0	290	0	0	0	0	0
20	2003	AUG	0	0	0	0	0	301	0	0	0	0
21	2003	SEP	0	0	0	0	0	0	296	0	0	0
22	2003	OCT	0	0	0	0	0	0	0	153	0	0
23	2003	NOV	0	0	0	0	0	0	0	0	91	0
24	2003	DEC	0	0	0	0	0	0	0	0	0	24

VARIABLE	DESCRIPTION
CDHBD_XX	Billing Cycle Residential Cooling Degree Hours per Billing Day for Month XX (03=March, etc.)

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of Data Shown:
___ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
_X_ Historical Years 2004 Through 2005
Witness: R. J. Alexander

FORECASTING MODEL: RESIDENTIAL ENERGY

(1) LINE NO.	(2) YEAR	(3) MONTH	(4) CDHBD_03 (INPUT)	(5) CDHBD_04 (INPUT)	(6) CDHBD_05 (INPUT)	(7) CDHBD_06 (INPUT)	(8) CDHBD_07 (INPUT)	(9) CDHBD_08 (INPUT)	(10) CDHBD_09 (INPUT)	(11) CDHBD_10 (INPUT)	(12) CDHBD_11 (INPUT)	(13) CDHBD_12 (INPUT)
1	2004	JAN	0	0	0	0	0	0	0	0	0	0
2	2004	FEB	0	0	0	0	0	0	0	0	0	0
3	2004	MAR	17	0	0	0	0	0	0	0	0	0
4	2004	APR	0	45	0	0	0	0	0	0	0	0
5	2004	MAY	0	0	117	0	0	0	0	0	0	0
6	2004	JUN	0	0	0	268	0	0	0	0	0	0
7	2004	JUL	0	0	0	0	323	0	0	0	0	0
8	2004	AUG	0	0	0	0	0	329	0	0	0	0
9	2004	SEP	0	0	0	0	0	0	290	0	0	0
10	2004	OCT	0	0	0	0	0	0	0	228	0	0
11	2004	NOV	0	0	0	0	0	0	0	0	124	0
12	2004	DEC	0	0	0	0	0	0	0	0	0	26
13	2005	JAN	0	0	0	0	0	0	0	0	0	0
14	2005	FEB	0	0	0	0	0	0	0	0	0	0
15	2005	MAR	11	0	0	0	0	0	0	0	0	0
16	2005	APR	0	29	0	0	0	0	0	0	0	0
17	2005	MAY	0	0	92	0	0	0	0	0	0	0
18	2005	JUN	0	0	0	257	0	0	0	0	0	0
19	2005	JUL	0	0	0	0	340	0	0	0	0	0
20	2005	AUG	0	0	0	0	0	341	0	0	0	0
21	2005	SEP	0	0	0	0	0	0	353	0	0	0
22	2005	OCT	0	0	0	0	0	0	0	270	0	0
23	2005	NOV	0	0	0	0	0	0	0	0	79	0
24	2005	DEC	0	0	0	0	0	0	0	0	0	27

VARIABLE	DESCRIPTION
CDHBD_XX	Billing Cycle Residential Cooling Degree Hours per Billing Day for Month XX (03=March, etc.)

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of Data Shown:
___ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
_X_ Historical Years 2006 Through 2007
Witness: R. J. Alexander

FORECASTING MODEL: RESIDENTIAL ENERGY

(1) LINE NO.	(2) YEAR	(3) MONTH	(4) CDHBD_03 (INPUT)	(5) CDHBD_04 (INPUT)	(6) CDHBD_05 (INPUT)	(7) CDHBD_06 (INPUT)	(8) CDHBD_07 (INPUT)	(9) CDHBD_08 (INPUT)	(10) CDHBD_09 (INPUT)	(11) CDHBD_10 (INPUT)	(12) CDHBD_11 (INPUT)	(13) CDHBD_12 (INPUT)
1	2006	JAN	0	0	0	0	0	0	0	0	0	0
2	2006	FEB	0	0	0	0	0	0	0	0	0	0
3	2006	MAR	31	0	0	0	0	0	0	0	0	0
4	2006	APR	0	86	0	0	0	0	0	0	0	0
5	2006	MAY	0	0	164	0	0	0	0	0	0	0
6	2006	JUN	0	0	0	301	0	0	0	0	0	0
7	2006	JUL	0	0	0	0	385	0	0	0	0	0
8	2006	AUG	0	0	0	0	0	355	0	0	0	0
9	2006	SEP	0	0	0	0	0	0	320	0	0	0
10	2006	OCT	0	0	0	0	0	0	0	200	0	0
11	2006	NOV	0	0	0	0	0	0	0	0	54	0
12	2006	DEC	0	0	0	0	0	0	0	0	0	12
13	2007	JAN	0	0	0	0	0	0	0	0	0	0
14	2007	FEB	0	0	0	0	0	0	0	0	0	0
15	2007	MAR	20	0	0	0	0	0	0	0	0	0
16	2007	APR	0	63	0	0	0	0	0	0	0	0
17	2007	MAY	0	0	147	0	0	0	0	0	0	0
18	2007	JUN	0	0	0	248	0	0	0	0	0	0
19	2007	JUL	0	0	0	0	344	0	0	0	0	0
20	2007	AUG	0	0	0	0	0	380	0	0	0	0
21	2007	SEP	0	0	0	0	0	0	353	0	0	0
22	2007	OCT	0	0	0	0	0	0	0	243	0	0
23	2007	NOV	0	0	0	0	0	0	0	0	70	0
24	2007	DEC	0	0	0	0	0	0	0	0	0	19

VARIABLE	DESCRIPTION
CDHBD_XX	Billing Cycle Residential Cooling Degree Hours per Billing Day for Month XX (03=March, etc.)

Supporting Schedules: Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of Data Shown:
___ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
_X_ Historical Years 2008 Through 2009
Witness: R. J. Alexander

FORECASTING MODEL: RESIDENTIAL ENERGY

(1) LINE NO.	(2) YEAR	(3) MONTH	(4) CDHBD_03 (INPUT)	(5) CDHBD_04 (INPUT)	(6) CDHBD_05 (INPUT)	(7) CDHBD_06 (INPUT)	(8) CDHBD_07 (INPUT)	(9) CDHBD_08 (INPUT)	(10) CDHBD_09 (INPUT)	(11) CDHBD_10 (INPUT)	(12) CDHBD_11 (INPUT)	(13) CDHBD_12 (INPUT)
1	2008	JAN	0	0	0	0	0	0	0	0	0	0
2	2008	FEB	0	0	0	0	0	0	0	0	0	0
3	2008	MAR	10	0	0	0	0	0	0	0	0	0
4	2008	APR	0	43	0	0	0	0	0	0	0	0
5	2008	MAY	0	0	133	0	0	0	0	0	0	0
6	2008	JUN	0	0	0	318	0	0	0	0	0	0
7	2008	JUL	0	0	0	0	368	0	0	0	0	0
8	2008	AUG	0	0	0	0	0	387	0	0	0	0
9	2008	SEP	0	0	0	0	0	0	339	0	0	0
10	2008	OCT	0	0	0	0	0	0	0	182	0	0
11	2008	NOV	0	0	0	0	0	0	0	0	47	0
12	2008	DEC	0	0	0	0	0	0	0	0	0	15
13	2009	JAN	0	0	0	0	0	0	0	0	0	0
14	2009	FEB	0	0	0	0	0	0	0	0	0	0
15	2009	MAR	19	0	0	0	0	0	0	0	0	0
16	2009	APR	0	38	0	0	0	0	0	0	0	0
17	2009	MAY	0	0	142	0	0	0	0	0	0	0
18	2009	JUN	0	0	0	270	0	0	0	0	0	0
19	2009	JUL	0	0	0	0	382	0	0	0	0	0
20	2009	AUG	0	0	0	0	0	325	0	0	0	0
21	2009	SEP	0	0	0	0	0	0	270	0	0	0
22	2009	OCT	0	0	0	0	0	0	0	236	0	0
23	2009	NOV	0	0	0	0	0	0	0	0	69	0
24	2009	DEC	0	0	0	0	0	0	0	0	0	9

VARIABLE	DESCRIPTION
CDHBD_XX	Billing Cycle Residential Cooling Degree Hours per Billing Day for Month XX (03=March, etc.)

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of Data Shown:
___ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
_X_ Historical Years 2010 Through 2011
Witness: R. J. Alexander

FORECASTING MODEL: RESIDENTIAL ENERGY

(1) LINE NO.	(2) YEAR	(3) MONTH	(4) CDHBD_03 (INPUT)	(5) CDHBD_04 (INPUT)	(6) CDHBD_05 (INPUT)	(7) CDHBD_06 (INPUT)	(8) CDHBD_07 (INPUT)	(9) CDHBD_08 (INPUT)	(10) CDHBD_09 (INPUT)	(11) CDHBD_10 (INPUT)	(12) CDHBD_11 (INPUT)	(13) CDHBD_12 (INPUT)
1	2010	JAN	0	0	0	0	0	0	0	0	0	0
2	2010	FEB	0	0	0	0	0	0	0	0	0	0
3	2010	MAR	1	0	0	0	0	0	0	0	0	0
4	2010	APR	0	33	0	0	0	0	0	0	0	0
5	2010	MAY	0	0	133	0	0	0	0	0	0	0
6	2010	JUN	0	0	0	295	0	0	0	0	0	0
7	2010	JUL	0	0	0	0	369	0	0	0	0	0
8	2010	AUG	0	0	0	0	0	413	0	0	0	0
9	2010	SEP	0	0	0	0	0	0	340	0	0	0
10	2010	OCT	0	0	0	0	0	0	0	213	0	0
11	2010	NOV	0	0	0	0	0	0	0	0	94	0
12	2010	DEC	0	0	0	0	0	0	0	0	0	22
13	2011	JAN	0	0	0	0	0	0	0	0	0	0
14	2011	FEB	0	0	0	0	0	0	0	0	0	0
15	2011	MAR	28	0	0	0	0	0	0	0	0	0
16	2011	APR	0	89	0	0	0	0	0	0	0	0
17	2011	MAY	0	0	157	0	0	0	0	0	0	0
18	2011	JUN	0	0	0	312	0	0	0	0	0	0
19	2011	JUL	0	0	0	0	390	0	0	0	0	0
20	2011	AUG	0	0	0	0	0	388	0	0	0	0
21	2011	SEP	0	0	0	0	0	0	328	0	0	0
22	2011	OCT	0	0	0	0	0	0	0	161	0	0
23	2011	NOV	0	0	0	0	0	0	0	0	52	0
24	2011	DEC	0	0	0	0	0	0	0	0	0	22

VARIABLE	DESCRIPTION
CDHBD_XX	Billing Cycle Residential Cooling Degree Hours per Billing Day for Month XX (03=March, etc.)

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of Data Shown:
___ Projected Test Year Ended 12/31/14
_X_ Prior Year Ended 12/31/13
_X_ Historical Year 2012
Witness: R. J. Alexander

FORECASTING MODEL: RESIDENTIAL ENERGY

(1) LINE NO.	(2) YEAR	(3) MONTH	(4) CDHBD_03 (INPUT)	(5) CDHBD_04 (INPUT)	(6) CDHBD_05 (INPUT)	(7) CDHBD_06 (INPUT)	(8) CDHBD_07 (INPUT)	(9) CDHBD_08 (INPUT)	(10) CDHBD_09 (INPUT)	(11) CDHBD_10 (INPUT)	(12) CDHBD_11 (INPUT)	(13) CDHBD_12 (INPUT)
1	2012	JAN	0	0	0	0	0	0	0	0	0	0
2	2012	FEB	0	0	0	0	0	0	0	0	0	0
3	2012	MAR	37	0	0	0	0	0	0	0	0	0
4	2012	APR	0	104	0	0	0	0	0	0	0	0
5	2012	MAY	0	0	166	0	0	0	0	0	0	0
6	2012	JUN	0	0	0	298	0	0	0	0	0	0
7	2012	JUL	0	0	0	0	342	0	0	0	0	0
8	2012	AUG	0	0	0	0	0	353	0	0	0	0
9	2012	SEP	0	0	0	0	0	0	314	0	0	0
10	2012	OCT	0	0	0	0	0	0	0	192	0	0
11	2012	NOV	0	0	0	0	0	0	0	0	76	0
12	2012	DEC	0	0	0	0	0	0	0	0	0	21
13	2013	JAN	0	0	0	0	0	0	0	0	0	0
14	2013	FEB	0	0	0	0	0	0	0	0	0	0
15	2013	MAR	19	0	0	0	0	0	0	0	0	0
16	2013	APR	0	54	0	0	0	0	0	0	0	0
17	2013	MAY	0	0	139	0	0	0	0	0	0	0
18	2013	JUN	0	0	0	271	0	0	0	0	0	0
19	2013	JUL	0	0	0	0	350	0	0	0	0	0
20	2013	AUG	0	0	0	0	0	353	0	0	0	0
21	2013	SEP	0	0	0	0	0	0	321	0	0	0
22	2013	OCT	0	0	0	0	0	0	0	203	0	0
23	2013	NOV	0	0	0	0	0	0	0	0	76	0
24	2013	DEC	0	0	0	0	0	0	0	0	0	21

VARIABLE	DESCRIPTION
CDHBD_XX	Billing Cycle Residential Cooling Degree Hours per Billing Day for Month XX (03=March, etc.)

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of Data Shown:
_X_ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
___ Historical Year 2012
Witness: R. J. Alexander

FORECASTING MODEL: RESIDENTIAL ENERGY

(1) LINE NO.	(2) YEAR	(3) MONTH	(4) CDHBD_03 (INPUT)	(5) CDHBD_04 (INPUT)	(6) CDHBD_05 (INPUT)	(7) CDHBD_06 (INPUT)	(8) CDHBD_07 (INPUT)	(9) CDHBD_08 (INPUT)	(10) CDHBD_09 (INPUT)	(11) CDHBD_10 (INPUT)	(12) CDHBD_11 (INPUT)	(13) CDHBD_12 (INPUT)
1	2014	JAN	0	0	0	0	0	0	0	0	0	0
2	2014	FEB	0	0	0	0	0	0	0	0	0	0
3	2014	MAR	19	0	0	0	0	0	0	0	0	0
4	2014	APR	0	54	0	0	0	0	0	0	0	0
5	2014	MAY	0	0	139	0	0	0	0	0	0	0
6	2014	JUN	0	0	0	271	0	0	0	0	0	0
7	2014	JUL	0	0	0	0	350	0	0	0	0	0
8	2014	AUG	0	0	0	0	0	353	0	0	0	0
9	2014	SEP	0	0	0	0	0	0	321	0	0	0
10	2014	OCT	0	0	0	0	0	0	0	203	0	0
11	2014	NOV	0	0	0	0	0	0	0	0	76	0
12	2014	DEC	0	0	0	0	0	0	0	0	0	21

VARIABLE	DESCRIPTION
CDHBD_XX	Billing Cycle Residential Cooling Degree Hours per Billing Day for Month XX (03=March, etc.)

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of Data Shown:
___ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
_X_ Historical Years 1992 Through 1993
Witness: R. J. Alexander

FORECASTING MODEL: RESIDENTIAL ENERGY

(1) LINE NO.	(2) YEAR	(3) MONTH	(4) HDHBD_01 (INPUT)	(5) HDHBD_02 (INPUT)	(6) HDHBD_03 (INPUT)	(7) HDHBD_04 (INPUT)	(8) HDHBD_11 (INPUT)	(9) HDHBD_12 (INPUT)
1	1992	NOV	0	0	0	0	41	0
2	1992	DEC	0	0	0	0	0	138
3	1993	JAN	90	0	0	0	0	0
4	1993	FEB	0	150	0	0	0	0
5	1993	MAR	0	0	144	0	0	0
6	1993	APR	0	0	0	65	0	0
7	1993	MAY	0	0	0	0	0	0
8	1993	JUN	0	0	0	0	0	0
9	1993	JUL	0	0	0	0	0	0
10	1993	AUG	0	0	0	0	0	0
11	1993	SEP	0	0	0	0	0	0
12	1993	OCT	0	0	0	0	0	0
13	1993	NOV	0	0	0	0	71	0
14	1993	DEC	0	0	0	0	0	135

VARIABLE	DESCRIPTION
HDHBD_XX	Billing Cycle Residential Heating Degree Hours per Billing Day for Month XX (01=January, etc.)

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of Data Shown:
___ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
_X_ Historical Years 1994 Through 1995
Witness: R. J. Alexander

FORECASTING MODEL: RESIDENTIAL ENERGY

(1) LINE NO.	(2) YEAR	(3) MONTH	(4) HDHBD_01 (INPUT)	(5) HDHBD_02 (INPUT)	(6) HDHBD_03 (INPUT)	(7) HDHBD_04 (INPUT)	(8) HDHBD_11 (INPUT)	(9) HDHBD_12 (INPUT)
1	1994	JAN	272	0	0	0	0	0
2	1994	FEB	0	213	0	0	0	0
3	1994	MAR	0	0	91	0	0	0
4	1994	APR	0	0	0	45	0	0
5	1994	MAY	0	0	0	0	0	0
6	1994	JUN	0	0	0	0	0	0
7	1994	JUL	0	0	0	0	0	0
8	1994	AUG	0	0	0	0	0	0
9	1994	SEP	0	0	0	0	0	0
10	1994	OCT	0	0	0	0	0	0
11	1994	NOV	0	0	0	0	13	0
12	1994	DEC	0	0	0	0	0	72
13	1995	JAN	162	0	0	0	0	0
14	1995	FEB	0	186	0	0	0	0
15	1995	MAR	0	0	96	0	0	0
16	1995	APR	0	0	0	33	0	0
17	1995	MAY	0	0	0	0	0	0
18	1995	JUN	0	0	0	0	0	0
19	1995	JUL	0	0	0	0	0	0
20	1995	AUG	0	0	0	0	0	0
21	1995	SEP	0	0	0	0	0	0
22	1995	OCT	0	0	0	0	0	0
23	1995	NOV	0	0	0	0	50	0
24	1995	DEC	0	0	0	0	0	144

VARIABLE	DESCRIPTION
HDHBD_XX	Billing Cycle Residential Heating Degree Hours per Billing Day for Month XX (01=January, etc.)

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of Data Shown:
___ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
_X_ Historical Years 1996 Through 1997
Witness: R. J. Alexander

FORECASTING MODEL: RESIDENTIAL ENERGY

(1) LINE NO.	(2) YEAR	(3) MONTH	(4) HDHBD_01 (INPUT)	(5) HDHBD_02 (INPUT)	(6) HDHBD_03 (INPUT)	(7) HDHBD_04 (INPUT)	(8) HDHBD_11 (INPUT)	(9) HDHBD_12 (INPUT)
1	1996	JAN	275	0	0	0	0	0
2	1996	FEB	0	252	0	0	0	0
3	1996	MAR	0	0	156	0	0	0
4	1996	APR	0	0	0	81	0	0
5	1996	MAY	0	0	0	0	0	0
6	1996	JUN	0	0	0	0	0	0
7	1996	JUL	0	0	0	0	0	0
8	1996	AUG	0	0	0	0	0	0
9	1996	SEP	0	0	0	0	0	0
10	1996	OCT	0	0	0	0	0	0
11	1996	NOV	0	0	0	0	42	0
12	1996	DEC	0	0	0	0	0	115
13	1997	JAN	179	0	0	0	0	0
14	1997	FEB	0	179	0	0	0	0
15	1997	MAR	0	0	63	0	0	0
16	1997	APR	0	0	0	22	0	0
17	1997	MAY	0	0	0	0	0	0
18	1997	JUN	0	0	0	0	0	0
19	1997	JUL	0	0	0	0	0	0
20	1997	AUG	0	0	0	0	0	0
21	1997	SEP	0	0	0	0	0	0
22	1997	OCT	0	0	0	0	0	0
23	1997	NOV	0	0	0	0	75	0
24	1997	DEC	0	0	0	0	0	155

VARIABLE	DESCRIPTION
HDHBD_XX	Billing Cycle Residential Heating Degree Hours per Billing Day for Month XX (01=January, etc.)

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of Data Shown:
___ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
_X_ Historical Years 1998 Through 1999
Witness: R. J. Alexander

FORECASTING MODEL: RESIDENTIAL ENERGY

(1) LINE NO.	(2) YEAR	(3) MONTH	(4) HDHBD_01 (INPUT)	(5) HDHBD_02 (INPUT)	(6) HDHBD_03 (INPUT)	(7) HDHBD_04 (INPUT)	(8) HDHBD_11 (INPUT)	(9) HDHBD_12 (INPUT)
1	1998	JAN	179	0	0	0	0	0
2	1998	FEB	0	175	0	0	0	0
3	1998	MAR	0	0	131	0	0	0
4	1998	APR	0	0	0	51	0	0
5	1998	MAY	0	0	0	0	0	0
6	1998	JUN	0	0	0	0	0	0
7	1998	JUL	0	0	0	0	0	0
8	1998	AUG	0	0	0	0	0	0
9	1998	SEP	0	0	0	0	0	0
10	1998	OCT	0	0	0	0	0	0
11	1998	NOV	0	0	0	0	24	0
12	1998	DEC	0	0	0	0	0	46
13	1999	JAN	206	0	0	0	0	0
14	1999	FEB	0	87	0	0	0	0
15	1999	MAR	0	0	102	0	0	0
16	1999	APR	0	0	0	37	0	0
17	1999	MAY	0	0	0	0	0	0
18	1999	JUN	0	0	0	0	0	0
19	1999	JUL	0	0	0	0	0	0
20	1999	AUG	0	0	0	0	0	0
21	1999	SEP	0	0	0	0	0	0
22	1999	OCT	0	0	0	0	0	0
23	1999	NOV	0	0	0	0	50	0
24	1999	DEC	0	0	0	0	0	109

VARIABLE	DESCRIPTION
HDHBD_XX	Billing Cycle Residential Heating Degree Hours per Billing Day for Month XX (01=January, etc.)

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of Data Shown:
___ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
_X_ Historical Years 2000 Through 2001
Witness: R. J. Alexander

FORECASTING MODEL: RESIDENTIAL ENERGY

(1) LINE NO.	(2) YEAR	(3) MONTH	(4) HDHBD_01 (INPUT)	(5) HDHBD_02 (INPUT)	(6) HDHBD_03 (INPUT)	(7) HDHBD_04 (INPUT)	(8) HDHBD_11 (INPUT)	(9) HDHBD_12 (INPUT)
1	2000	JAN	170	0	0	0	0	0
2	2000	FEB	0	207	0	0	0	0
3	2000	MAR	0	0	57	0	0	0
4	2000	APR	0	0	0	31	0	0
5	2000	MAY	0	0	0	0	0	0
6	2000	JUN	0	0	0	0	0	0
7	2000	JUL	0	0	0	0	0	0
8	2000	AUG	0	0	0	0	0	0
9	2000	SEP	0	0	0	0	0	0
10	2000	OCT	0	0	0	0	0	0
11	2000	NOV	0	0	0	0	52	0
12	2000	DEC	0	0	0	0	0	208
13	2001	JAN	348	0	0	0	0	0
14	2001	FEB	0	183	0	0	0	0
15	2001	MAR	0	0	77	0	0	0
16	2001	APR	0	0	0	51	0	0
17	2001	MAY	0	0	0	0	0	0
18	2001	JUN	0	0	0	0	0	0
19	2001	JUL	0	0	0	0	0	0
20	2001	AUG	0	0	0	0	0	0
21	2001	SEP	0	0	0	0	0	0
22	2001	OCT	0	0	0	0	0	0
23	2001	NOV	0	0	0	0	39	0
24	2001	DEC	0	0	0	0	0	61

VARIABLE	DESCRIPTION
HDHBD_XX	Billing Cycle Residential Heating Degree Hours per Billing Day for Month XX (01=January, etc.)

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of Data Shown:
___ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
_X_ Historical Years 2002 Through 2003
Witness: R. J. Alexander

FORECASTING MODEL: RESIDENTIAL ENERGY

(1) LINE NO.	(2) YEAR	(3) MONTH	(4) HDHBD_01 (INPUT)	(5) HDHBD_02 (INPUT)	(6) HDHBD_03 (INPUT)	(7) HDHBD_04 (INPUT)	(8) HDHBD_11 (INPUT)	(9) HDHBD_12 (INPUT)
1	2002	JAN	246	0	0	0	0	0
2	2002	FEB	0	153	0	0	0	0
3	2002	MAR	0	0	174	0	0	0
4	2002	APR	0	0	0	35	0	0
5	2002	MAY	0	0	0	0	0	0
6	2002	JUN	0	0	0	0	0	0
7	2002	JUL	0	0	0	0	0	0
8	2002	AUG	0	0	0	0	0	0
9	2002	SEP	0	0	0	0	0	0
10	2002	OCT	0	0	0	0	0	0
11	2002	NOV	0	0	0	0	43	0
12	2002	DEC	0	0	0	0	0	183
13	2003	JAN	251	0	0	0	0	0
14	2003	FEB	0	233	0	0	0	0
15	2003	MAR	0	0	71	0	0	0
16	2003	APR	0	0	0	35	0	0
17	2003	MAY	0	0	0	0	0	0
18	2003	JUN	0	0	0	0	0	0
19	2003	JUL	0	0	0	0	0	0
20	2003	AUG	0	0	0	0	0	0
21	2003	SEP	0	0	0	0	0	0
22	2003	OCT	0	0	0	0	0	0
23	2003	NOV	0	0	0	0	20	0
24	2003	DEC	0	0	0	0	0	166

VARIABLE	DESCRIPTION
HDHBD_XX	Billing Cycle Residential Heating Degree Hours per Billing Day for Month XX (01=January, etc.)

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of Data Shown:
___ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
_X_ Historical Years 2004 Through 2005
Witness: R. J. Alexander

FORECASTING MODEL: RESIDENTIAL ENERGY

(1) LINE NO.	(2) YEAR	(3) MONTH	(4) HDHBD_01 (INPUT)	(5) HDHBD_02 (INPUT)	(6) HDHBD_03 (INPUT)	(7) HDHBD_04 (INPUT)	(8) HDHBD_11 (INPUT)	(9) HDHBD_12 (INPUT)
1	2004	JAN	233	0	0	0	0	0
2	2004	FEB	0	221	0	0	0	0
3	2004	MAR	0	0	113	0	0	0
4	2004	APR	0	0	0	47	0	0
5	2004	MAY	0	0	0	0	0	0
6	2004	JUN	0	0	0	0	0	0
7	2004	JUL	0	0	0	0	0	0
8	2004	AUG	0	0	0	0	0	0
9	2004	SEP	0	0	0	0	0	0
10	2004	OCT	0	0	0	0	0	0
11	2004	NOV	0	0	0	0	14	0
12	2004	DEC	0	0	0	0	0	110
13	2005	JAN	182	0	0	0	0	0
14	2005	FEB	0	164	0	0	0	0
15	2005	MAR	0	0	105	0	0	0
16	2005	APR	0	0	0	35	0	0
17	2005	MAY	0	0	0	0	0	0
18	2005	JUN	0	0	0	0	0	0
19	2005	JUL	0	0	0	0	0	0
20	2005	AUG	0	0	0	0	0	0
21	2005	SEP	0	0	0	0	0	0
22	2005	OCT	0	0	0	0	0	0
23	2005	NOV	0	0	0	0	43	0
24	2005	DEC	0	0	0	0	0	132

VARIABLE	DESCRIPTION
HDHBD_XX	Billing Cycle Residential Heating Degree Hours per Billing Day for Month XX (01=January, etc.)

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of Data Shown:
___ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
_X_ Historical Years 2006 Through 2007
Witness: R. J. Alexander

FORECASTING MODEL: RESIDENTIAL ENERGY

(1) LINE NO.	(2) YEAR	(3) MONTH	(4) HDHBD_01 (INPUT)	(5) HDHBD_02 (INPUT)	(6) HDHBD_03 (INPUT)	(7) HDHBD_04 (INPUT)	(8) HDHBD_11 (INPUT)	(9) HDHBD_12 (INPUT)
1	2006	JAN	148	0	0	0	0	0
2	2006	FEB	0	127	0	0	0	0
3	2006	MAR	0	0	80	0	0	0
4	2006	APR	0	0	0	33	0	0
5	2006	MAY	0	0	0	0	0	0
6	2006	JUN	0	0	0	0	0	0
7	2006	JUL	0	0	0	0	0	0
8	2006	AUG	0	0	0	0	0	0
9	2006	SEP	0	0	0	0	0	0
10	2006	OCT	0	0	0	0	0	0
11	2006	NOV	0	0	0	0	62	0
12	2006	DEC	0	0	0	0	0	159
13	2007	JAN	128	0	0	0	0	0
14	2007	FEB	0	230	0	0	0	0
15	2007	MAR	0	0	107	0	0	0
16	2007	APR	0	0	0	38	0	0
17	2007	MAY	0	0	0	0	0	0
18	2007	JUN	0	0	0	0	0	0
19	2007	JUL	0	0	0	0	0	0
20	2007	AUG	0	0	0	0	0	0
21	2007	SEP	0	0	0	0	0	0
22	2007	OCT	0	0	0	0	0	0
23	2007	NOV	0	0	0	0	44	0
24	2007	DEC	0	0	0	0	0	94

VARIABLE	DESCRIPTION
HDHBD_XX	Billing Cycle Residential Heating Degree Hours per Billing Day for Month XX (01=January, etc.)

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of Data Shown:
___ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
_X_ Historical Years 2008 Through 2009
Witness: R. J. Alexander

FORECASTING MODEL: RESIDENTIAL ENERGY

(1) LINE NO.	(2) YEAR	(3) MONTH	(4) HDHBD_01 (INPUT)	(5) HDHBD_02 (INPUT)	(6) HDHBD_03 (INPUT)	(7) HDHBD_04 (INPUT)	(8) HDHBD_11 (INPUT)	(9) HDHBD_12 (INPUT)
1	2008	JAN	186	0	0	0	0	0
2	2008	FEB	0	182	0	0	0	0
3	2008	MAR	0	0	113	0	0	0
4	2008	APR	0	0	0	41	0	0
5	2008	MAY	0	0	0	0	0	0
6	2008	JUN	0	0	0	0	0	0
7	2008	JUL	0	0	0	0	0	0
8	2008	AUG	0	0	0	0	0	0
9	2008	SEP	0	0	0	0	0	0
10	2008	OCT	0	0	0	0	0	0
11	2008	NOV	0	0	0	0	70	0
12	2008	DEC	0	0	0	0	0	152
13	2009	JAN	139	0	0	0	0	0
14	2009	FEB	0	210	0	0	0	0
15	2009	MAR	0	0	110	0	0	0
16	2009	APR	0	0	0	25	0	0
17	2009	MAY	0	0	0	0	0	0
18	2009	JUN	0	0	0	0	0	0
19	2009	JUL	0	0	0	0	0	0
20	2009	AUG	0	0	0	0	0	0
21	2009	SEP	0	0	0	0	0	0
22	2009	OCT	0	0	0	0	0	0
23	2009	NOV	0	0	0	0	46	0
24	2009	DEC	0	0	0	0	0	147

VARIABLE	DESCRIPTION
HDHBD_XX	Billing Cycle Residential Heating Degree Hours per Billing Day for Month XX (01=January, etc.)

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of Data Shown:
___ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
_X_ Historical Years 2010 Through 2011
Witness: R. J. Alexander

FORECASTING MODEL: RESIDENTIAL ENERGY

(1) LINE NO.	(2) YEAR	(3) MONTH	(4) HDHBD_01 (INPUT)	(5) HDHBD_02 (INPUT)	(6) HDHBD_03 (INPUT)	(7) HDHBD_04 (INPUT)	(8) HDHBD_11 (INPUT)	(9) HDHBD_12 (INPUT)
1	2010	JAN	317	0	0	0	0	0
2	2010	FEB	0	267	0	0	0	0
3	2010	MAR	0	0	227	0	0	0
4	2010	APR	0	0	0	49	0	0
5	2010	MAY	0	0	0	0	0	0
6	2010	JUN	0	0	0	0	0	0
7	2010	JUL	0	0	0	0	0	0
8	2010	AUG	0	0	0	0	0	0
9	2010	SEP	0	0	0	0	0	0
10	2010	OCT	0	0	0	0	0	0
11	2010	NOV	0	0	0	0	38	0
12	2010	DEC	0	0	0	0	0	191
13	2011	JAN	280	0	0	0	0	0
14	2011	FEB	0	250	0	0	0	0
15	2011	MAR	0	0	84	0	0	0
16	2011	APR	0	0	0	23	0	0
17	2011	MAY	0	0	0	0	0	0
18	2011	JUN	0	0	0	0	0	0
19	2011	JUL	0	0	0	0	0	0
20	2011	AUG	0	0	0	0	0	0
21	2011	SEP	0	0	0	0	0	0
22	2011	OCT	0	0	0	0	0	0
23	2011	NOV	0	0	0	0	56	0
24	2011	DEC	0	0	0	0	0	114

VARIABLE	DESCRIPTION
HDHBD_XX	Billing Cycle Residential Heating Degree Hours per Billing Day for Month XX (01=January, etc.)

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of Data Shown:
___ Projected Test Year Ended 12/31/14
_X_ Prior Year Ended 12/31/13
_X_ Historical Year 2012
Witness: R. J. Alexander

FORECASTING MODEL: RESIDENTIAL ENERGY

(1) LINE NO.	(2) YEAR	(3) MONTH	(4) HDHBD_01 (INPUT)	(5) HDHBD_02 (INPUT)	(6) HDHBD_03 (INPUT)	(7) HDHBD_04 (INPUT)	(8) HDHBD_11 (INPUT)	(9) HDHBD_12 (INPUT)
1	2012	JAN	117	0	0	0	0	0
2	2012	FEB	0	91	0	0	0	0
3	2012	MAR	0	0	48	0	0	0
4	2012	APR	0	0	0	4	0	0
5	2012	MAY	0	0	0	0	0	0
6	2012	JUN	0	0	0	0	0	0
7	2012	JUL	0	0	0	0	0	0
8	2012	AUG	0	0	0	0	0	0
9	2012	SEP	0	0	0	0	0	0
10	2012	OCT	0	0	0	0	0	0
11	2012	NOV	0	0	0	0	45	0
12	2012	DEC	0	0	0	0	0	132
13	2013	JAN	205	0	0	0	0	0
14	2013	FEB	0	188	0	0	0	0
15	2013	MAR	0	0	107	0	0	0
16	2013	APR	0	0	0	39	0	0
17	2013	MAY	0	0	0	0	0	0
18	2013	JUN	0	0	0	0	0	0
19	2013	JUL	0	0	0	0	0	0
20	2013	AUG	0	0	0	0	0	0
21	2013	SEP	0	0	0	0	0	0
22	2013	OCT	0	0	0	0	0	0
23	2013	NOV	0	0	0	0	45	0
24	2013	DEC	0	0	0	0	0	132

VARIABLE	DESCRIPTION
HDHBD_XX	Billing Cycle Residential Heating Degree Hours per Billing Day for Month XX (01=January, etc.)

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of Data Shown:
X Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
___ Historical Year 2012
Witness: R. J. Alexander

FORECASTING MODEL: RESIDENTIAL ENERGY

(1) LINE NO.	(2) YEAR	(3) MONTH	(4) HDHBD_01 (INPUT)	(5) HDHBD_02 (INPUT)	(6) HDHBD_03 (INPUT)	(7) HDHBD_04 (INPUT)	(8) HDHBD_11 (INPUT)	(9) HDHBD_12 (INPUT)
1	2014	JAN	205	0	0	0	0	0
2	2014	FEB	0	188	0	0	0	0
3	2014	MAR	0	0	107	0	0	0
4	2014	APR	0	0	0	39	0	0
5	2014	MAY	0	0	0	0	0	0
6	2014	JUN	0	0	0	0	0	0
7	2014	JUL	0	0	0	0	0	0
8	2014	AUG	0	0	0	0	0	0
9	2014	SEP	0	0	0	0	0	0
10	2014	OCT	0	0	0	0	0	0
11	2014	NOV	0	0	0	0	45	0
12	2014	DEC	0	0	0	0	0	132

VARIABLE	DESCRIPTION
HDHBD_XX	Billing Cycle Residential Heating Degree Hours per Billing Day for Month XX (01=January, etc.)

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of Data Shown:
___ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
_X_ Historical Years 1992 Through 1993
Witness: R. J. Alexander

FORECASTING MODEL: SMALL COMMERCIAL ENERGY

(1) LINE NO.	(2) YEAR	(3) MONTH	(4) SmComSales (OUTPUT)	(5) SmComSales (INPUT)	(6) NonMfgEmp (INPUT)	(7) ComPrice (INPUT)	(8) Ivan (INPUT)	(9) Bin_0897 (INPUT)	(10) HDHBD_01 (INPUT)	(11) HDHBD_02 (INPUT)	(12) HDHBD_03 (INPUT)	(13) HDHBD_12 (INPUT)
1	1992	NOV		21.177	229.070	7.334	0	0	0	0	0	0
2	1992	DEC	21.185	20.474	229.700	7.344	0	0	0	0	0	138
3	1993	JAN	20.379	20.234	230.400	7.354	0	0	90	0	0	0
4	1993	FEB	22.175	22.007	231.210	7.378	0	0	0	150	0	0
5	1993	MAR	21.078	19.565	232.170	7.403	0	0	0	0	144	0
6	1993	APR	18.114	20.029	233.120	7.437	0	0	0	0	0	0
7	1993	MAY	21.560	20.215	233.750	7.432	0	0	0	0	0	0
8	1993	JUN	26.749	26.506	233.930	7.442	0	0	0	0	0	0
9	1993	JUL	30.994	32.235	233.970	7.452	0	0	0	0	0	0
10	1993	AUG	33.465	33.250	234.300	7.456	0	0	0	0	0	0
11	1993	SEP	31.353	30.995	235.190	7.428	0	0	0	0	0	0
12	1993	OCT	26.755	27.153	236.430	7.421	0	0	0	0	0	0
13	1993	NOV	21.167	21.093	237.640	7.373	0	0	0	0	0	0
14	1993	DEC	21.071	21.286	238.550	7.329	0	0	0	0	0	135

VARIABLE	DESCRIPTION
SmComSales	Billing Cycle Small Commercial kWh per Customer per Billing Day
NonMfgEmp	Non-manufacturing Employment (000's)
ComPrice	12-Month Average of Real Commercial Price (cents per kWh)
Ivan	Binary Variable for Hurricane Ivan September 2004
Bin_0897	Binary Variable for August 1997
HDHBD_XX	Billing Cycle Small Commercial Heating Degree Hours per Billing Day for Month XX (01=January, etc.)

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of Data Shown:
___ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
_X_ Historical Years 1994 Through 1995
Witness: R. J. Alexander

FORECASTING MODEL: SMALL COMMERCIAL ENERGY

(1) LINE NO.	(2) YEAR	(3) MONTH	(4) SmComSales (OUTPUT)	(5) SmComSales (INPUT)	(6) NonMfgEmp (INPUT)	(7) ComPrice (INPUT)	(8) Ivan (INPUT)	(9) Bin_0897 (INPUT)	(10) HDHBD_01 (INPUT)	(11) HDHBD_02 (INPUT)	(12) HDHBD_03 (INPUT)	(13) HDHBD_12 (INPUT)
1	1994	JAN	25.826	25.848	239.270	7.284	0	0	272	0	0	0
2	1994	FEB	24.659	24.891	239.960	7.232	0	0	0	213	0	0
3	1994	MAR	20.854	20.504	240.780	7.195	0	0	0	0	91	0
4	1994	APR	20.307	20.655	241.730	7.154	0	0	0	0	0	0
5	1994	MAY	23.719	23.451	242.680	7.145	0	0	0	0	0	0
6	1994	JUN	27.979	28.195	243.540	7.119	0	0	0	0	0	0
7	1994	JUL	30.647	30.331	244.280	7.110	0	0	0	0	0	0
8	1994	AUG	30.137	29.827	244.920	7.110	0	0	0	0	0	0
9	1994	SEP	29.572	29.981	245.420	7.099	0	0	0	0	0	0
10	1994	OCT	26.167	26.065	245.840	7.110	0	0	0	0	0	0
11	1994	NOV	21.455	21.156	246.210	7.145	0	0	0	0	0	0
12	1994	DEC	20.089	20.913	246.550	7.173	0	0	0	0	0	72
13	1995	JAN	23.544	22.558	246.810	7.196	0	0	162	0	0	0
14	1995	FEB	23.701	24.160	246.920	7.242	0	0	0	186	0	0
15	1995	MAR	21.000	21.779	246.870	7.264	0	0	0	0	96	0
16	1995	APR	20.955	20.932	246.880	7.279	0	0	0	0	0	0
17	1995	MAY	23.807	22.670	247.250	7.284	0	0	0	0	0	0
18	1995	JUN	29.094	30.583	248.090	7.301	0	0	0	0	0	0
19	1995	JUL	32.625	31.824	249.040	7.302	0	0	0	0	0	0
20	1995	AUG	33.135	32.523	249.580	7.309	0	0	0	0	0	0
21	1995	SEP	32.718	33.313	249.400	7.321	0	0	0	0	0	0
22	1995	OCT	28.205	27.870	248.960	7.318	0	0	0	0	0	0
23	1995	NOV	21.373	21.342	248.940	7.309	0	0	0	0	0	0
24	1995	DEC	21.529	21.468	249.770	7.309	0	0	0	0	0	144

VARIABLE	DESCRIPTION
SmComSales	Billing Cycle Small Commercial kWh per Customer per Billing Day
NonMfgEmp	Non-manufacturing Employment (000's)
ComPrice	12-Month Average of Real Commercial Price (cents per kWh)
ivan	Binary Variable for Hurricane Ivan September 2004
Bin_0897	Binary Variable for August 1997
HDHBD_XX	Billing Cycle Small Commercial Heating Degree Hours per Billing Day for Month XX (01=January, etc.)

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of Data Shown:
___ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
_X_ Historical Years 1996 Through 1997
Witness: R. J. Alexander

FORECASTING MODEL: SMALL COMMERCIAL ENERGY

(1) LINE NO.	(2) YEAR	(3) MONTH	(4) SmComSales (OUTPUT)	(5) SmComSales (INPUT)	(6) NonMfgEmp (INPUT)	(7) ComPrice (INPUT)	(8) Ivan (INPUT)	(9) Bin_0897 (INPUT)	(10) HDHBD_01 (INPUT)	(11) HDHBD_02 (INPUT)	(12) HDHBD_03 (INPUT)	(13) HDHBD_12 (INPUT)
1	1996	JAN	26.086	27.021	251.130	7.310	0	0	275	0	0	0
2	1996	FEB	26.593	26.314	252.380	7.273	0	0	0	252	0	0
3	1996	MAR	22.607	23.303	253.160	7.267	0	0	0	0	156	0
4	1996	APR	20.326	21.232	253.590	7.266	0	0	0	0	0	0
5	1996	MAY	24.333	22.542	253.950	7.255	0	0	0	0	0	0
6	1996	JUN	29.902	30.096	254.470	7.239	0	0	0	0	0	0
7	1996	JUL	33.603	32.909	255.210	7.226	0	0	0	0	0	0
8	1996	AUG	33.157	32.280	256.190	7.203	0	0	0	0	0	0
9	1996	SEP	30.558	30.737	257.290	7.194	0	0	0	0	0	0
10	1996	OCT	26.506	26.567	258.270	7.172	0	0	0	0	0	0
11	1996	NOV	22.289	21.165	258.800	7.161	0	0	0	0	0	0
12	1996	DEC	20.747	21.044	258.690	7.159	0	0	0	0	0	115
13	1997	JAN	23.774	24.033	258.300	7.148	0	0	179	0	0	0
14	1997	FEB	24.346	21.713	258.160	7.152	0	0	0	179	0	0
15	1997	MAR	19.175	21.000	258.560	7.133	0	0	0	0	63	0
16	1997	APR	21.578	20.486	259.320	7.108	0	0	0	0	0	0
17	1997	MAY	22.261	20.467	260.060	7.070	0	0	0	0	0	0
18	1997	JUN	26.492	25.908	260.510	7.044	0	0	0	0	0	0
19	1997	JUL	31.457	34.174	260.770	7.028	0	0	0	0	0	0
20	1997	AUG	28.446	28.142	261.070	7.014	0	1	0	0	0	0
21	1997	SEP	32.833	32.332	261.570	6.990	0	0	0	0	0	0
22	1997	OCT	28.767	29.322	262.200	6.966	0	0	0	0	0	0
23	1997	NOV	21.682	21.764	262.820	6.929	0	0	0	0	0	0
24	1997	DEC	22.897	21.913	263.340	6.894	0	0	0	0	0	155

VARIABLE	DESCRIPTION
SmComSales	Billing Cycle Small Commercial kWh per Customer per Billing Day
NonMfgEmp	Non-manufacturing Employment (000's)
ComPrice	12-Month Average of Real Commercial Price (cents per kWh)
Ivan	Binary Variable for Hurricane Ivan September 2004
Bin_0897	Binary Variable for August 1997
HDHBD_XX	Billing Cycle Small Commercial Heating Degree Hours per Billing Day for Month XX (01=January, etc.)

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of Data Shown:
___ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
_X_ Historical Years 1998 Through 1999
Witness: R. J. Alexander

FORECASTING MODEL: SMALL COMMERCIAL ENERGY

(1) LINE NO.	(2) YEAR	(3) MONTH	(4) SmComSales (OUTPUT)	(5) SmComSales (INPUT)	(6) NonMfgEmp (INPUT)	(7) ComPrice (INPUT)	(8) Ivan (INPUT)	(9) Bin_0897 (INPUT)	(10) HDHBD_01 (INPUT)	(11) HDHBD_02 (INPUT)	(12) HDHBD_03 (INPUT)	(13) HDHBD_12 (INPUT)
1	1998	JAN	24.065	23.275	263.870	6.842	0	0	179	0	0	0
2	1998	FEB	23.994	25.273	264.490	6.822	0	0	0	175	0	0
3	1998	MAR	23.067	21.159	265.290	6.795	0	0	0	0	131	0
4	1998	APR	20.372	22.546	266.100	6.756	0	0	0	0	0	0
5	1998	MAY	25.493	25.479	266.620	6.697	0	0	0	0	0	0
6	1998	JUN	33.451	34.561	266.720	6.625	0	0	0	0	0	0
7	1998	JUL	36.623	39.446	266.650	6.552	0	0	0	0	0	0
8	1998	AUG	36.451	35.367	266.800	6.497	0	0	0	0	0	0
9	1998	SEP	33.478	33.337	267.410	6.438	0	0	0	0	0	0
10	1998	OCT	29.791	34.010	268.140	6.365	0	0	0	0	0	0
11	1998	NOV	26.219	25.986	268.500	6.344	0	0	0	0	0	0
12	1998	DEC	22.856	24.426	268.200	6.249	0	0	0	0	0	46
13	1999	JAN	27.726	27.466	267.540	6.196	0	0	206	0	0	0
14	1999	FEB	23.897	20.849	267.070	6.136	0	0	0	87	0	0
15	1999	MAR	21.468	24.260	267.070	6.072	0	0	0	0	102	0
16	1999	APR	23.478	25.246	267.430	6.028	0	0	0	0	0	0
17	1999	MAY	26.869	28.096	267.870	6.020	0	0	0	0	0	0
18	1999	JUN	31.394	32.626	268.180	6.017	0	0	0	0	0	0
19	1999	JUL	34.861	37.219	268.380	6.018	0	0	0	0	0	0
20	1999	AUG	38.016	38.619	268.600	6.010	0	0	0	0	0	0
21	1999	SEP	35.208	36.477	268.900	6.007	0	0	0	0	0	0
22	1999	OCT	29.900	29.889	269.220	6.029	0	0	0	0	0	0
23	1999	NOV	24.035	26.801	269.440	6.000	0	0	0	0	0	0
24	1999	DEC	25.082	24.373	269.540	6.011	0	0	0	0	0	109

VARIABLE	DESCRIPTION
SmComSales	Billing Cycle Small Commercial kWh per Customer per Billing Day
NonMfgEmp	Non-manufacturing Employment (000's)
ComPrice	12-Month Average of Real Commercial Price (cents per kWh)
Ivan	Binary Variable for Hurricane Ivan September 2004
Bin_0897	Binary Variable for August 1997
HDHBD_XX	Billing Cycle Small Commercial Heating Degree Hours per Billing Day for Month XX (01=January, etc.)

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of Data Shown:
___ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
_X_ Historical Years 2000 Through 2001
Witness: R. J. Alexander

FORECASTING MODEL: SMALL COMMERCIAL ENERGY

(1) LINE NO.	(2) YEAR	(3) MONTH	(4) SmComSales (OUTPUT)	(5) SmComSales (INPUT)	(6) NonMfgEmp (INPUT)	(7) ComPrice (INPUT)	(8) Ivan (INPUT)	(9) Bin_0897 (INPUT)	(10) HDHBD_01 (INPUT)	(11) HDHBD_02 (INPUT)	(12) HDHBD_03 (INPUT)	(13) HDHBD_12 (INPUT)
1	2000	JAN	26.132	25.542	269.660	6.009	0	0	170	0	0	0
2	2000	FEB	26.688	28.745	270.030	6.022	0	0	0	207	0	0
3	2000	MAR	23.337	23.688	270.780	6.036	0	0	0	0	57	0
4	2000	APR	23.376	20.336	271.730	6.044	0	0	0	0	0	0
5	2000	MAY	23.799	26.558	272.570	6.060	0	0	0	0	0	0
6	2000	JUN	32.795	33.373	273.100	6.072	0	0	0	0	0	0
7	2000	JUL	36.473	33.614	273.260	6.086	0	0	0	0	0	0
8	2000	AUG	34.587	35.515	273.100	6.097	0	0	0	0	0	0
9	2000	SEP	33.162	34.628	272.720	6.104	0	0	0	0	0	0
10	2000	OCT	28.016	26.447	272.440	6.106	0	0	0	0	0	0
11	2000	NOV	23.295	23.445	272.630	6.120	0	0	0	0	0	0
12	2000	DEC	24.399	24.704	273.480	6.138	0	0	0	0	0	208
13	2001	JAN	29.908	31.306	274.680	6.159	0	0	348	0	0	0
14	2001	FEB	26.796	24.978	275.630	6.135	0	0	0	183	0	0
15	2001	MAR	21.944	21.917	276.070	6.118	0	0	0	0	77	0
16	2001	APR	22.118	22.977	276.160	6.098	0	0	0	0	0	0
17	2001	MAY	25.209	24.865	276.230	6.076	0	0	0	0	0	0
18	2001	JUN	30.799	30.056	276.500	6.054	0	0	0	0	0	0
19	2001	JUL	32.453	29.700	276.870	6.033	0	0	0	0	0	0
20	2001	AUG	31.829	33.506	277.130	6.009	0	0	0	0	0	0
21	2001	SEP	31.871	30.327	277.130	5.988	0	0	0	0	0	0
22	2001	OCT	25.780	24.596	276.980	5.971	0	0	0	0	0	0
23	2001	NOV	21.983	21.161	276.860	5.948	0	0	0	0	0	0
24	2001	DEC	20.843	20.755	276.910	5.925	0	0	0	0	0	61

VARIABLE	DESCRIPTION
SmComSales	Billing Cycle Small Commercial kWh per Customer per Billing Day
NonMfgEmp	Non-manufacturing Employment (000's)
ComPrice	12-Month Average of Real Commercial Price (cents per kWh)
Ivan	Binary Variable for Hurricane Ivan September 2004
Bin_0897	Binary Variable for August 1997
HDHBD_XX	Billing Cycle Small Commercial Heating Degree Hours per Billing Day for Month XX (01=January, etc.)

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of Data Shown:
___ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
_X_ Historical Years 2002 Through 2003
Witness: R. J. Alexander

FORECASTING MODEL: SMALL COMMERCIAL ENERGY

(1) LINE NO.	(2) YEAR	(3) MONTH	(4) SmComSales (OUTPUT)	(5) SmComSales (INPUT)	(6) NonMfgEmp (INPUT)	(7) ComPrice (INPUT)	(8) Ivan (INPUT)	(9) Bin_0897 (INPUT)	(10) HDHBD_01 (INPUT)	(11) HDHBD_02 (INPUT)	(12) HDHBD_03 (INPUT)	(13) HDHBD_12 (INPUT)
1	2002	JAN	26.614	25.608	277.170	5.898	0	0	246	0	0	0
2	2002	FEB	24.180	23.551	277.610	5.913	0	0	0	153	0	0
3	2002	MAR	23.732	23.146	278.200	5.923	0	0	0	0	174	0
4	2002	APR	21.775	22.427	278.810	5.945	0	0	0	0	0	0
5	2002	MAY	27.248	27.228	279.230	5.960	0	0	0	0	0	0
6	2002	JUN	30.328	28.575	279.370	5.966	0	0	0	0	0	0
7	2002	JUL	31.956	32.512	279.410	6.018	0	0	0	0	0	0
8	2002	AUG	33.754	33.329	279.690	6.072	0	0	0	0	0	0
9	2002	SEP	32.740	31.337	280.370	6.124	0	0	0	0	0	0
10	2002	OCT	29.344	30.319	281.260	6.171	0	0	0	0	0	0
11	2002	NOV	23.314	22.153	282.020	6.212	0	0	0	0	0	0
12	2002	DEC	23.626	23.030	282.440	6.267	0	0	0	0	0	183
13	2003	JAN	26.680	25.904	282.640	6.330	0	0	251	0	0	0
14	2003	FEB	26.431	26.441	282.810	6.373	0	0	0	233	0	0
15	2003	MAR	21.858	21.908	283.150	6.422	0	0	0	0	71	0
16	2003	APR	22.316	21.397	283.830	6.461	0	0	0	0	0	0
17	2003	MAY	25.803	25.887	284.960	6.506	0	0	0	0	0	0
18	2003	JUN	30.418	30.292	286.560	6.558	0	0	0	0	0	0
19	2003	JUL	31.861	31.313	288.320	6.566	0	0	0	0	0	0
20	2003	AUG	32.369	32.165	289.810	6.579	0	0	0	0	0	0
21	2003	SEP	31.975	31.947	290.730	6.587	0	0	0	0	0	0
22	2003	OCT	26.895	26.783	291.400	6.597	0	0	0	0	0	0
23	2003	NOV	23.881	23.180	292.300	6.615	0	0	0	0	0	0
24	2003	DEC	23.697	23.494	293.700	6.624	0	0	0	0	0	166

VARIABLE	DESCRIPTION
SmComSales	Billing Cycle Small Commercial kWh per Customer per Billing Day
NonMfgEmp	Non-manufacturing Employment (000's)
ComPrice	12-Month Average of Real Commercial Price (cents per kWh)
Ivan	Binary Variable for Hurricane Ivan September 2004
Bin_0897	Binary Variable for August 1997
HDHBD_XX	Billing Cycle Small Commercial Heating Degree Hours per Billing Day for Month XX (01=January, etc.)

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of Data Shown:
___ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
_X_ Historical Years 2004 Through 2005
Witness: R. J. Alexander

FORECASTING MODEL: SMALL COMMERCIAL ENERGY

(1) LINE NO.	(2) YEAR	(3) MONTH	(4) SmComSales (OUTPUT)	(5) SmComSales (INPUT)	(6) NonMfgEmp (INPUT)	(7) ComPrice (INPUT)	(8) Ivan (INPUT)	(9) Bin_0897 (INPUT)	(10) HDHBD_01 (INPUT)	(11) HDHBD_02 (INPUT)	(12) HDHBD_03 (INPUT)	(13) HDHBD_12 (INPUT)
1	2004	JAN	26.862	25.511	295.430	6.628	0	0	233	0	0	0
2	2004	FEB	26.336	26.172	297.000	6.643	0	0	0	221	0	0
3	2004	MAR	23.004	22.927	298.210	6.647	0	0	0	0	113	0
4	2004	APR	22.232	21.037	299.140	6.657	0	0	0	0	0	0
5	2004	MAY	24.165	23.839	299.990	6.660	0	0	0	0	0	0
6	2004	JUN	30.744	30.679	300.840	6.673	0	0	0	0	0	0
7	2004	JUL	33.353	33.317	301.530	6.681	0	0	0	0	0	0
8	2004	AUG	34.047	33.977	301.790	6.683	0	0	0	0	0	0
9	2004	SEP	26.812	26.500	301.490	6.688	1	0	0	0	0	0
10	2004	OCT	30.116	29.602	301.110	6.701	0	0	0	0	0	0
11	2004	NOV	24.954	24.541	301.230	6.726	0	0	0	0	0	0
12	2004	DEC	22.942	22.771	302.260	6.715	0	0	0	0	0	110
13	2005	JAN	25.833	24.892	303.920	6.713	0	0	182	0	0	0
14	2005	FEB	25.295	25.200	305.570	6.733	0	0	0	164	0	0
15	2005	MAR	23.300	23.278	306.920	6.759	0	0	0	0	105	0
16	2005	APR	22.168	22.295	308.000	6.783	0	0	0	0	0	0
17	2005	MAY	24.491	23.603	308.900	6.824	0	0	0	0	0	0
18	2005	JUN	30.744	30.702	309.760	6.872	0	0	0	0	0	0
19	2005	JUL	34.343	33.331	310.790	6.918	0	0	0	0	0	0
20	2005	AUG	34.218	34.342	312.230	6.970	0	0	0	0	0	0
21	2005	SEP	34.770	34.604	314.110	7.018	0	0	0	0	0	0
22	2005	OCT	32.088	31.160	316.140	7.061	0	0	0	0	0	0
23	2005	NOV	23.627	23.933	317.860	7.075	0	0	0	0	0	0
24	2005	DEC	23.990	24.357	318.940	7.126	0	0	0	0	0	132

VARIABLE	DESCRIPTION
SmComSales	Billing Cycle Small Commercial kWh per Customer per Billing Day
NonMfgEmp	Non-manufacturing Employment (000's)
ComPrice	12-Month Average of Real Commercial Price (cents per kWh)
Ivan	Binary Variable for Hurricane Ivan September 2004
Bin_0897	Binary Variable for August 1997
HDHBD_XX	Billing Cycle Small Commercial Heating Degree Hours per Billing Day for Month XX (01=January, etc.)

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of Data Shown:
___ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
_X_ Historical Years 2006 Through 2007
Witness: R. J. Alexander

FORECASTING MODEL: SMALL COMMERCIAL ENERGY

(1) LINE NO.	(2) YEAR	(3) MONTH	(4) SmComSales (OUTPUT)	(5) SmComSales (INPUT)	(6) NonMfgEmp (INPUT)	(7) ComPrice (INPUT)	(8) Ivan (INPUT)	(9) Bin_0897 (INPUT)	(10) HDHBD_01 (INPUT)	(11) HDHBD_02 (INPUT)	(12) HDHBD_03 (INPUT)	(13) HDHBD_12 (INPUT)
1	2006	JAN	25.728	25.098	319.410	7.171	0	0	148	0	0	0
2	2006	FEB	24.968	24.447	319.420	7.208	0	0	0	127	0	0
3	2006	MAR	22.942	22.899	319.140	7.245	0	0	0	0	80	0
4	2006	APR	23.965	23.928	318.760	7.279	0	0	0	0	0	0
5	2006	MAY	26.764	28.341	318.510	7.301	0	0	0	0	0	0
6	2006	JUN	33.888	33.958	318.570	7.305	0	0	0	0	0	0
7	2006	JUL	37.052	37.632	318.890	7.320	0	0	0	0	0	0
8	2006	AUG	36.336	38.437	319.400	7.329	0	0	0	0	0	0
9	2006	SEP	35.647	36.630	319.960	7.341	0	0	0	0	0	0
10	2006	OCT	31.276	30.462	320.460	7.355	0	0	0	0	0	0
11	2006	NOV	23.992	24.841	320.760	7.378	0	0	0	0	0	0
12	2006	DEC	25.475	25.657	320.780	7.401	0	0	0	0	0	159
13	2007	JAN	25.636	26.150	320.580	7.422	0	0	128	0	0	0
14	2007	FEB	28.705	28.414	320.330	7.472	0	0	0	230	0	0
15	2007	MAR	24.128	24.795	320.110	7.523	0	0	0	0	107	0
16	2007	APR	24.004	24.239	319.890	7.577	0	0	0	0	0	0
17	2007	MAY	26.736	26.893	319.640	7.630	0	0	0	0	0	0
18	2007	JUN	31.208	31.175	319.300	7.693	0	0	0	0	0	0
19	2007	JUL	34.837	35.644	318.780	7.754	0	0	0	0	0	0
20	2007	AUG	36.859	38.069	317.990	7.813	0	0	0	0	0	0
21	2007	SEP	35.833	36.924	316.940	7.872	0	0	0	0	0	0
22	2007	OCT	32.101	31.776	315.840	7.928	0	0	0	0	0	0
23	2007	NOV	23.978	24.704	314.960	7.981	0	0	0	0	0	0
24	2007	DEC	23.571	22.801	314.470	8.037	0	0	0	0	0	94

VARIABLE	DESCRIPTION
SmComSales	Billing Cycle Small Commercial kWh per Customer per Billing Day
NonMfgEmp	Non-manufacturing Employment (000's)
ComPrice	12-Month Average of Real Commercial Price (cents per kWh)
Ivan	Binary Variable for Hurricane Ivan September 2004
Bin_0897	Binary Variable for August 1997
HDHBD_XX	Billing Cycle Small Commercial Heating Degree Hours per Billing Day for Month XX (01=January, etc.)

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of Data Shown:
___ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
_X_ Historical Years 2008 Through 2009
Witness: R. J. Alexander

FORECASTING MODEL: SMALL COMMERCIAL ENERGY

(1) LINE NO.	(2) YEAR	(3) MONTH	(4) SmComSales (OUTPUT)	(5) SmComSales (INPUT)	(6) NonMfgEmp (INPUT)	(7) ComPrice (INPUT)	(8) Ivan (INPUT)	(9) Bin_0897 (INPUT)	(10) HDHBD_01 (INPUT)	(11) HDHBD_02 (INPUT)	(12) HDHBD_03 (INPUT)	(13) HDHBD_12 (INPUT)
1	2008	JAN	25.835	26.258	314.070	8.091	0	0	186	0	0	0
2	2008	FEB	26.259	27.560	313.380	8.084	0	0	0	182	0	0
3	2008	MAR	24.271	23.779	312.150	8.072	0	0	0	0	113	0
4	2008	APR	22.424	23.760	310.610	8.063	0	0	0	0	0	0
5	2008	MAY	26.079	25.469	309.190	8.050	0	0	0	0	0	0
6	2008	JUN	33.007	32.406	308.170	8.039	0	0	0	0	0	0
7	2008	JUL	34.675	34.376	307.340	8.023	0	0	0	0	0	0
8	2008	AUG	35.591	34.862	306.340	8.012	0	0	0	0	0	0
9	2008	SEP	32.986	33.533	304.960	7.999	0	0	0	0	0	0
10	2008	OCT	27.703	27.500	303.330	8.067	0	0	0	0	0	0
11	2008	NOV	21.818	23.665	301.690	8.141	0	0	0	0	0	0
12	2008	DEC	24.157	23.367	300.230	8.227	0	0	0	0	0	152
13	2009	JAN	23.976	23.122	299.000	8.310	0	0	139	0	0	0
14	2009	FEB	25.457	26.084	298.060	8.461	0	0	0	210	0	0
15	2009	MAR	22.395	23.170	297.320	8.618	0	0	0	0	110	0
16	2009	APR	21.477	21.628	296.670	8.774	0	0	0	0	0	0
17	2009	MAY	24.658	24.716	295.980	8.933	0	0	0	0	0	0
18	2009	JUN	30.000	31.013	295.200	9.089	0	0	0	0	0	0
19	2009	JUL	34.848	35.028	294.430	9.254	0	0	0	0	0	0
20	2009	AUG	32.586	33.193	293.840	9.400	0	0	0	0	0	0
21	2009	SEP	30.161	29.528	293.580	9.550	0	0	0	0	0	0
22	2009	OCT	28.459	29.079	293.530	9.621	0	0	0	0	0	0
23	2009	NOV	21.686	21.910	293.500	9.680	0	0	0	0	0	0
24	2009	DEC	22.080	22.607	293.420	9.739	0	0	0	0	0	147

VARIABLE	DESCRIPTION
SmComSales	Billing Cycle Small Commercial kWh per Customer per Billing Day
NonMfgEmp	Non-manufacturing Employment (000's)
ComPrice	12-Month Average of Real Commercial Price (cents per kWh)
Ivan	Binary Variable for Hurricane Ivan September 2004
Bin_0897	Binary Variable for August 1997
HDHBD_XX	Billing Cycle Small Commercial Heating Degree Hours per Billing Day for Month XX (01=January, etc.)

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of Data Shown:
___ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
_X_ Historical Years 2010 Through 2011
Witness: R. J. Alexander

FORECASTING MODEL: SMALL COMMERCIAL ENERGY

(1) LINE NO.	(2) YEAR	(3) MONTH	(4) SmComSales (OUTPUT)	(5) SmComSales (INPUT)	(6) NonMfgEmp (INPUT)	(7) ComPrice (INPUT)	(8) Ivan (INPUT)	(9) Bin_0897 (INPUT)	(10) HDHBD_01 (INPUT)	(11) HDHBD_02 (INPUT)	(12) HDHBD_03 (INPUT)	(13) HDHBD_12 (INPUT)
1	2010	JAN	27.745	29.125	293.400	9.793	0	0	317	0	0	0
2	2010	FEB	27.512	28.366	293.650	9.805	0	0	0	267	0	0
3	2010	MAR	25.036	26.210	294.300	9.812	0	0	0	0	227	0
4	2010	APR	21.448	20.139	295.280	9.818	0	0	0	0	0	0
5	2010	MAY	23.420	23.963	296.400	9.826	0	0	0	0	0	0
6	2010	JUN	30.602	30.203	297.500	9.831	0	0	0	0	0	0
7	2010	JUL	33.294	33.312	298.380	9.830	0	0	0	0	0	0
8	2010	AUG	35.336	35.106	298.870	9.849	0	0	0	0	0	0
9	2010	SEP	31.961	32.311	298.900	9.862	0	0	0	0	0	0
10	2010	OCT	27.648	26.567	298.750	9.873	0	0	0	0	0	0
11	2010	NOV	21.572	22.116	298.820	9.894	0	0	0	0	0	0
12	2010	DEC	22.607	23.095	299.350	9.901	0	0	0	0	0	191
13	2011	JAN	26.688	27.475	300.170	9.922	0	0	280	0	0	0
14	2011	FEB	26.750	28.076	300.880	9.879	0	0	0	250	0	0
15	2011	MAR	22.214	21.250	301.310	9.836	0	0	0	0	84	0
16	2011	APR	22.078	21.488	301.570	9.798	0	0	0	0	0	0
17	2011	MAY	24.098	24.390	301.860	9.757	0	0	0	0	0	0
18	2011	JUN	31.147	30.409	302.280	9.710	0	0	0	0	0	0
19	2011	JUL	33.954	32.881	302.640	9.668	0	0	0	0	0	0
20	2011	AUG	33.738	33.229	302.600	9.625	0	0	0	0	0	0
21	2011	SEP	31.092	30.420	302.000	9.585	0	0	0	0	0	0
22	2011	OCT	24.849	25.364	301.140	9.554	0	0	0	0	0	0
23	2011	NOV	20.842	20.535	300.500	9.540	0	0	0	0	0	0
24	2011	DEC	21.165	21.196	300.330	9.530	0	0	0	0	0	114

VARIABLE	DESCRIPTION
SmComSales	Billing Cycle Small Commercial kWh per Customer per Billing Day
NonMfgEmp	Non-manufacturing Employment (000's)
ComPrice	12-Month Average of Real Commercial Price (cents per kWh)
Ivan	Binary Variable for Hurricane Ivan September 2004
Bin_0897	Binary Variable for August 1997
HDHBD_XX	Billing Cycle Small Commercial Heating Degree Hours per Billing Day for Month XX (01=January, etc.)

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of Data Shown:
___ Projected Test Year Ended 12/31/14
_X_ Prior Year Ended 12/31/13
_X_ Historical Year 2012
Witness: R. J. Alexander

FORECASTING MODEL: SMALL COMMERCIAL ENERGY

(1) LINE NO.	(2) YEAR	(3) MONTH	(4) SmComSales (OUTPUT)	(5) SmComSales (INPUT)	(6) NonMfgEmp (INPUT)	(7) ComPrice (INPUT)	(8) Ivan (INPUT)	(9) Bin_0897 (INPUT)	(10) HDHBD_01 (INPUT)	(11) HDHBD_02 (INPUT)	(12) HDHBD_03 (INPUT)	(13) HDHBD_12 (INPUT)
1	2012	JAN	22.272	20.465	300.340	9.510	0	0	117	0	0	0
2	2012	FEB	20.714	21.510	300.030	9.506	0	0	0	91	0	0
3	2012	MAR	20.129	20.620	299.150	9.524	0	0	0	0	48	0
4	2012	APR	22.603	22.328	298.040	9.499	0	0	0	0	0	0
5	2012	MAY	24.602	24.142	297.280	9.471	0	0	0	0	0	0
6	2012	JUN	30.256	29.006	297.270	9.462	0	0	0	0	0	0
7	2012	JUL	31.558	30.593	297.800	9.444	0	0	0	0	0	0
8	2012	AUG	32.140	30.707	298.480	9.359	0	0	0	0	0	0
9	2012	SEP	29.947	28.550	298.990	9.273	0	0	0	0	0	0
10	2012	OCT	25.397	25.767	299.290	9.178	0	0	0	0	0	0
11	2012	NOV	21.305		299.470	9.064	0	0	0	0	0	0
12	2012	DEC	21.692		299.570	8.949	0	0	0	0	0	132
13	2013	JAN	24.882		299.680	8.837	0	0	205	0	0	0
14	2013	FEB	24.953		299.840	8.743	0	0	0	188	0	0
15	2013	MAR	22.196		300.120	8.630	0	0	0	0	107	0
16	2013	APR	21.653		300.500	8.553	0	0	0	0	0	0
17	2013	MAY	24.614		300.950	8.482	0	0	0	0	0	0
18	2013	JUN	30.458		301.430	8.398	0	0	0	0	0	0
19	2013	JUL	33.769		301.950	8.321	0	0	0	0	0	0
20	2013	AUG	34.205		302.520	8.308	0	0	0	0	0	0
21	2013	SEP	32.645		303.110	8.296	0	0	0	0	0	0
22	2013	OCT	28.434		303.720	8.300	0	0	0	0	0	0
23	2013	NOV	22.907		304.300	8.303	0	0	0	0	0	0
24	2013	DEC	22.886		304.830	8.306	0	0	0	0	0	132

VARIABLE	DESCRIPTION
SmComSales	Billing Cycle Small Commercial kWh per Customer per Billing Day
NonMfgEmp	Non-manufacturing Employment (000's)
ComPrice	12-Month Average of Real Commercial Price (cents per kWh)
Ivan	Binary Variable for Hurricane Ivan September 2004
Bin_0897	Binary Variable for August 1997
HDHBD_XX	Billing Cycle Small Commercial Heating Degree Hours per Billing Day for Month XX (01=January, etc.)

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of Data Shown:
_X_ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
___ Historical Year 2012
Witness: R. J. Alexander

FORECASTING MODEL: SMALL COMMERCIAL ENERGY

(1) LINE NO.	(2) YEAR	(3) MONTH	(4) SmComSales (OUTPUT)	(5) SmComSales (INPUT)	(6) NonMfgEmp (INPUT)	(7) ComPrice (INPUT)	(8) Ivan (INPUT)	(9) Bin_0897 (INPUT)	(10) HDHBD_01 (INPUT)	(11) HDHBD_02 (INPUT)	(12) HDHBD_03 (INPUT)	(13) HDHBD_12 (INPUT)
1	2014	JAN	25.801		305.340	8.310	0	0	205	0	0	0
2	2014	FEB	25.662		305.850	8.354	0	0	0	188	0	0
3	2014	MAR	22.727		306.410	8.399	0	0	0	0	107	0
4	2014	APR	22.061		307.050	8.444	0	0	0	0	0	0
5	2014	MAY	24.921		307.750	8.489	0	0	0	0	0	0
6	2014	JUN	30.668		308.510	8.533	0	0	0	0	0	0
7	2014	JUL	33.896		309.320	8.576	0	0	0	0	0	0
8	2014	AUG	34.298		310.210	8.619	0	0	0	0	0	0
9	2014	SEP	32.708		311.120	8.661	0	0	0	0	0	0
10	2014	OCT	28.480		312.050	8.705	0	0	0	0	0	0
11	2014	NOV	22.935		312.970	8.749	0	0	0	0	0	0
12	2014	DEC	22.897		313.860	8.795	0	0	0	0	0	132

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VARIABLE	DESCRIPTION
SmComSales	Billing Cycle Small Commercial kWh per Customer per Billing Day
NonMfgEmp	Non-manufacturing Employment (000's)
ComPrice	12-Month Average of Real Commercial Price (cents per kWh)
Ivan	Binary Variable for Hurricane Ivan September 2004
Bin_0897	Binary Variable for August 1997
HDHBD_XX	Billing Cycle Small Commercial Heating Degree Hours per Billing Day for Month XX (01=January, etc.)

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of Data Shown:
___ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
_X_ Historical Years 1992 Through 1993
Witness: R. J. Alexander

FORECASTING MODEL: SMALL COMMERCIAL ENERGY

(1) LINE NO.	(2) YEAR	(3) MONTH	(4) CDHBD_04 (INPUT)	(5) CDHBD_05 (INPUT)	(6) CDHBD_06 (INPUT)	(7) CDHBD_07 (INPUT)	(8) CDHBD_08 (INPUT)	(9) CDHBD_09 (INPUT)	(10) CDHBD_10 (INPUT)	(11) CDHBD_11 (INPUT)
1	1992	NOV	0	0	0	0	0	0	0	69
2	1992	DEC	0	0	0	0	0	0	0	0
3	1993	JAN	0	0	0	0	0	0	0	0
4	1993	FEB	0	0	0	0	0	0	0	0
5	1993	MAR	0	0	0	0	0	0	0	0
6	1993	APR	31	0	0	0	0	0	0	0
7	1993	MAY	0	86	0	0	0	0	0	0
8	1993	JUN	0	0	238	0	0	0	0	0
9	1993	JUL	0	0	0	343	0	0	0	0
10	1993	AUG	0	0	0	0	375	0	0	0
11	1993	SEP	0	0	0	0	0	337	0	0
12	1993	OCT	0	0	0	0	0	0	215	0
13	1993	NOV	0	0	0	0	0	0	0	78
14	1993	DEC	0	0	0	0	0	0	0	0

VARIABLE	DESCRIPTION
CDHBD_XX	Billing Cycle Small Commercial Cooling Degree Hours per Billing Day for Month XX (04=April, etc.)

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of Data Shown:
___ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
_X_ Historical Years 1994 Through 1995
Witness: R. J. Alexander

FORECASTING MODEL: SMALL COMMERCIAL ENERGY

(1) LINE NO.	(2) YEAR	(3) MONTH	(4) CDHBD_04 (INPUT)	(5) CDHBD_05 (INPUT)	(6) CDHBD_06 (INPUT)	(7) CDHBD_07 (INPUT)	(8) CDHBD_08 (INPUT)	(9) CDHBD_09 (INPUT)	(10) CDHBD_10 (INPUT)	(11) CDHBD_11 (INPUT)
1	1994	JAN	0	0	0	0	0	0	0	0
2	1994	FEB	0	0	0	0	0	0	0	0
3	1994	MAR	0	0	0	0	0	0	0	0
4	1994	APR	54	0	0	0	0	0	0	0
5	1994	MAY	0	147	0	0	0	0	0	0
6	1994	JUN	0	0	243	0	0	0	0	0
7	1994	JUL	0	0	0	303	0	0	0	0
8	1994	AUG	0	0	0	0	289	0	0	0
9	1994	SEP	0	0	0	0	0	285	0	0
10	1994	OCT	0	0	0	0	0	0	180	0
11	1994	NOV	0	0	0	0	0	0	0	77
12	1994	DEC	0	0	0	0	0	0	0	0
13	1995	JAN	0	0	0	0	0	0	0	0
14	1995	FEB	0	0	0	0	0	0	0	0
15	1995	MAR	0	0	0	0	0	0	0	0
16	1995	APR	52	0	0	0	0	0	0	0
17	1995	MAY	0	143	0	0	0	0	0	0
18	1995	JUN	0	0	283	0	0	0	0	0
19	1995	JUL	0	0	0	340	0	0	0	0
20	1995	AUG	0	0	0	0	364	0	0	0
21	1995	SEP	0	0	0	0	0	372	0	0
22	1995	OCT	0	0	0	0	0	0	232	0
23	1995	NOV	0	0	0	0	0	0	0	79
24	1995	DEC	0	0	0	0	0	0	0	0

VARIABLE	DESCRIPTION
CDHBD_XX	Billing Cycle Small Commercial Cooling Degree Hours per Billing Day for Month XX (04=April, etc.)

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of Data Shown:
___ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
_X_ Historical Years 1996 Through 1997
Witness: R. J. Alexander

FORECASTING MODEL: SMALL COMMERCIAL ENERGY

(1) LINE NO.	(2) YEAR	(3) MONTH	(4) CDHBD_04 (INPUT)	(5) CDHBD_05 (INPUT)	(6) CDHBD_06 (INPUT)	(7) CDHBD_07 (INPUT)	(8) CDHBD_08 (INPUT)	(9) CDHBD_09 (INPUT)	(10) CDHBD_10 (INPUT)	(11) CDHBD_11 (INPUT)
1	1996	JAN	0	0	0	0	0	0	0	0
2	1996	FEB	0	0	0	0	0	0	0	0
3	1996	MAR	0	0	0	0	0	0	0	0
4	1996	APR	22	0	0	0	0	0	0	0
5	1996	MAY	0	133	0	0	0	0	0	0
6	1996	JUN	0	0	298	0	0	0	0	0
7	1996	JUL	0	0	0	379	0	0	0	0
8	1996	AUG	0	0	0	0	367	0	0	0
9	1996	SEP	0	0	0	0	0	316	0	0
10	1996	OCT	0	0	0	0	0	0	190	0
11	1996	NOV	0	0	0	0	0	0	0	94
12	1996	DEC	0	0	0	0	0	0	0	0
13	1997	JAN	0	0	0	0	0	0	0	0
14	1997	FEB	0	0	0	0	0	0	0	0
15	1997	MAR	0	0	0	0	0	0	0	0
16	1997	APR	65	0	0	0	0	0	0	0
17	1997	MAY	0	102	0	0	0	0	0	0
18	1997	JUN	0	0	221	0	0	0	0	0
19	1997	JUL	0	0	0	340	0	0	0	0
20	1997	AUG	0	0	0	0	339	0	0	0
21	1997	SEP	0	0	0	0	0	335	0	0
22	1997	OCT	0	0	0	0	0	0	231	0
23	1997	NOV	0	0	0	0	0	0	0	50
24	1997	DEC	0	0	0	0	0	0	0	0

VARIABLE	DESCRIPTION
CDHBD_XX	Billing Cycle Small Commercial Cooling Degree Hours per Billing Day for Month XX (04=April, etc.)

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of Data Shown:
___ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
_X_ Historical Years 1998 Through 1999
Witness: R. J. Alexander

FORECASTING MODEL: SMALL COMMERCIAL ENERGY

(1) LINE NO.	(2) YEAR	(3) MONTH	(4) CDHBD_04 (INPUT)	(5) CDHBD_05 (INPUT)	(6) CDHBD_06 (INPUT)	(7) CDHBD_07 (INPUT)	(8) CDHBD_08 (INPUT)	(9) CDHBD_09 (INPUT)	(10) CDHBD_10 (INPUT)	(11) CDHBD_11 (INPUT)
1	1998	JAN	0	0	0	0	0	0	0	0
2	1998	FEB	0	0	0	0	0	0	0	0
3	1998	MAR	0	0	0	0	0	0	0	0
4	1998	APR	44	0	0	0	0	0	0	0
5	1998	MAY	0	145	0	0	0	0	0	0
6	1998	JUN	0	0	341	0	0	0	0	0
7	1998	JUL	0	0	0	403	0	0	0	0
8	1998	AUG	0	0	0	0	355	0	0	0
9	1998	SEP	0	0	0	0	0	326	0	0
10	1998	OCT	0	0	0	0	0	0	229	0
11	1998	NOV	0	0	0	0	0	0	0	93
12	1998	DEC	0	0	0	0	0	0	0	0
13	1999	JAN	0	0	0	0	0	0	0	0
14	1999	FEB	0	0	0	0	0	0	0	0
15	1999	MAR	0	0	0	0	0	0	0	0
16	1999	APR	65	0	0	0	0	0	0	0
17	1999	MAY	0	143	0	0	0	0	0	0
18	1999	JUN	0	0	239	0	0	0	0	0
19	1999	JUL	0	0	0	323	0	0	0	0
20	1999	AUG	0	0	0	0	378	0	0	0
21	1999	SEP	0	0	0	0	0	331	0	0
22	1999	OCT	0	0	0	0	0	0	185	0
23	1999	NOV	0	0	0	0	0	0	0	67
24	1999	DEC	0	0	0	0	0	0	0	0

VARIABLE	DESCRIPTION
CDHBD_XX	Billing Cycle Small Commercial Cooling Degree Hours per Billing Day for Month XX (04=April, etc.)

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of Data Shown:
___ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
_X_ Historical Years 2000 Through 2001
Witness: R. J. Alexander

FORECASTING MODEL: SMALL COMMERCIAL ENERGY

(1) LINE NO.	(2) YEAR	(3) MONTH	(4) CDHBD_04 (INPUT)	(5) CDHBD_05 (INPUT)	(6) CDHBD_06 (INPUT)	(7) CDHBD_07 (INPUT)	(8) CDHBD_08 (INPUT)	(9) CDHBD_09 (INPUT)	(10) CDHBD_10 (INPUT)	(11) CDHBD_11 (INPUT)
1	2000	JAN	0	0	0	0	0	0	0	0
2	2000	FEB	0	0	0	0	0	0	0	0
3	2000	MAR	0	0	0	0	0	0	0	0
4	2000	APR	52	0	0	0	0	0	0	0
5	2000	MAY	0	131	0	0	0	0	0	0
6	2000	JUN	0	0	293	0	0	0	0	0
7	2000	JUL	0	0	0	384	0	0	0	0
8	2000	AUG	0	0	0	0	382	0	0	0
9	2000	SEP	0	0	0	0	0	329	0	0
10	2000	OCT	0	0	0	0	0	0	164	0
11	2000	NOV	0	0	0	0	0	0	0	93
12	2000	DEC	0	0	0	0	0	0	0	0
13	2001	JAN	0	0	0	0	0	0	0	0
14	2001	FEB	0	0	0	0	0	0	0	0
15	2001	MAR	0	0	0	0	0	0	0	0
16	2001	APR	53	0	0	0	0	0	0	0
17	2001	MAY	0	124	0	0	0	0	0	0
18	2001	JUN	0	0	262	0	0	0	0	0
19	2001	JUL	0	0	0	311	0	0	0	0
20	2001	AUG	0	0	0	0	326	0	0	0
21	2001	SEP	0	0	0	0	0	289	0	0
22	2001	OCT	0	0	0	0	0	0	147	0
23	2001	NOV	0	0	0	0	0	0	0	71
24	2001	DEC	0	0	0	0	0	0	0	0

VARIABLE	DESCRIPTION
CDHBD_XX	Billing Cycle Small Commercial Cooling Degree Hours per Billing Day for Month XX (04=April, etc.)

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of Data Shown:
___ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
_X_ Historical Years 2002 Through 2003
Witness: R. J. Alexander

FORECASTING MODEL: SMALL COMMERCIAL ENERGY

(1) LINE NO.	(2) YEAR	(3) MONTH	(4) CDHBD_04 (INPUT)	(5) CDHBD_05 (INPUT)	(6) CDHBD_06 (INPUT)	(7) CDHBD_07 (INPUT)	(8) CDHBD_08 (INPUT)	(9) CDHBD_09 (INPUT)	(10) CDHBD_10 (INPUT)	(11) CDHBD_11 (INPUT)
1	2002	JAN	0	0	0	0	0	0	0	0
2	2002	FEB	0	0	0	0	0	0	0	0
3	2002	MAR	0	0	0	0	0	0	0	0
4	2002	APR	56	0	0	0	0	0	0	0
5	2002	MAY	0	197	0	0	0	0	0	0
6	2002	JUN	0	0	248	0	0	0	0	0
7	2002	JUL	0	0	0	313	0	0	0	0
8	2002	AUG	0	0	0	0	333	0	0	0
9	2002	SEP	0	0	0	0	0	319	0	0
10	2002	OCT	0	0	0	0	0	0	239	0
11	2002	NOV	0	0	0	0	0	0	0	73
12	2002	DEC	0	0	0	0	0	0	0	0
13	2003	JAN	0	0	0	0	0	0	0	0
14	2003	FEB	0	0	0	0	0	0	0	0
15	2003	MAR	0	0	0	0	0	0	0	0
16	2003	APR	57	0	0	0	0	0	0	0
17	2003	MAY	0	174	0	0	0	0	0	0
18	2003	JUN	0	0	261	0	0	0	0	0
19	2003	JUL	0	0	0	290	0	0	0	0
20	2003	AUG	0	0	0	0	301	0	0	0
21	2003	SEP	0	0	0	0	0	296	0	0
22	2003	OCT	0	0	0	0	0	0	153	0
23	2003	NOV	0	0	0	0	0	0	0	91
24	2003	DEC	0	0	0	0	0	0	0	0

VARIABLE	DESCRIPTION
CDHBD_XX	Billing Cycle Small Commercial Cooling Degree Hours per Billing Day for Month XX (04=April, etc.)

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FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of Data Shown:
___ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
_X_ Historical Years 2004 Through 2005
Witness: R. J. Alexander

FORECASTING MODEL: SMALL COMMERCIAL ENERGY

(1) LINE NO.	(2) YEAR	(3) MONTH	(4) CDHBD_04 (INPUT)	(5) CDHBD_05 (INPUT)	(6) CDHBD_06 (INPUT)	(7) CDHBD_07 (INPUT)	(8) CDHBD_08 (INPUT)	(9) CDHBD_09 (INPUT)	(10) CDHBD_10 (INPUT)	(11) CDHBD_11 (INPUT)
1	2004	JAN	0	0	0	0	0	0	0	0
2	2004	FEB	0	0	0	0	0	0	0	0
3	2004	MAR	0	0	0	0	0	0	0	0
4	2004	APR	45	0	0	0	0	0	0	0
5	2004	MAY	0	117	0	0	0	0	0	0
6	2004	JUN	0	0	268	0	0	0	0	0
7	2004	JUL	0	0	0	323	0	0	0	0
8	2004	AUG	0	0	0	0	329	0	0	0
9	2004	SEP	0	0	0	0	0	290	0	0
10	2004	OCT	0	0	0	0	0	0	228	0
11	2004	NOV	0	0	0	0	0	0	0	124
12	2004	DEC	0	0	0	0	0	0	0	0
13	2005	JAN	0	0	0	0	0	0	0	0
14	2005	FEB	0	0	0	0	0	0	0	0
15	2005	MAR	0	0	0	0	0	0	0	0
16	2005	APR	29	0	0	0	0	0	0	0
17	2005	MAY	0	92	0	0	0	0	0	0
18	2005	JUN	0	0	257	0	0	0	0	0
19	2005	JUL	0	0	0	340	0	0	0	0
20	2005	AUG	0	0	0	0	341	0	0	0
21	2005	SEP	0	0	0	0	0	353	0	0
22	2005	OCT	0	0	0	0	0	0	270	0
23	2005	NOV	0	0	0	0	0	0	0	79
24	2005	DEC	0	0	0	0	0	0	0	0

VARIABLE	DESCRIPTION
CDHBD_XX	Billing Cycle Small Commercial Cooling Degree Hours per Billing Day for Month XX (04=April, etc.)

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FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of Data Shown:
___ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
_X_ Historical Years 2006 Through 2007
Witness: R. J. Alexander

FORECASTING MODEL: SMALL COMMERCIAL ENERGY

(1) LINE NO.	(2) YEAR	(3) MONTH	(4) CDHBD_04 (INPUT)	(5) CDHBD_05 (INPUT)	(6) CDHBD_06 (INPUT)	(7) CDHBD_07 (INPUT)	(8) CDHBD_08 (INPUT)	(9) CDHBD_09 (INPUT)	(10) CDHBD_10 (INPUT)	(11) CDHBD_11 (INPUT)
1	2006	JAN	0	0	0	0	0	0	0	0
2	2006	FEB	0	0	0	0	0	0	0	0
3	2006	MAR	0	0	0	0	0	0	0	0
4	2006	APR	86	0	0	0	0	0	0	0
5	2006	MAY	0	164	0	0	0	0	0	0
6	2006	JUN	0	0	301	0	0	0	0	0
7	2006	JUL	0	0	0	385	0	0	0	0
8	2006	AUG	0	0	0	0	355	0	0	0
9	2006	SEP	0	0	0	0	0	320	0	0
10	2006	OCT	0	0	0	0	0	0	200	0
11	2006	NOV	0	0	0	0	0	0	0	54
12	2006	DEC	0	0	0	0	0	0	0	0
13	2007	JAN	0	0	0	0	0	0	0	0
14	2007	FEB	0	0	0	0	0	0	0	0
15	2007	MAR	0	0	0	0	0	0	0	0
16	2007	APR	63	0	0	0	0	0	0	0
17	2007	MAY	0	147	0	0	0	0	0	0
18	2007	JUN	0	0	248	0	0	0	0	0
19	2007	JUL	0	0	0	344	0	0	0	0
20	2007	AUG	0	0	0	0	380	0	0	0
21	2007	SEP	0	0	0	0	0	353	0	0
22	2007	OCT	0	0	0	0	0	0	243	0
23	2007	NOV	0	0	0	0	0	0	0	70
24	2007	DEC	0	0	0	0	0	0	0	0

VARIABLE	DESCRIPTION
CDHBD_XX	Billing Cycle Small Commercial Cooling Degree Hours per Billing Day for Month XX (04=April, etc.)

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of Data Shown:
___ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
_X_ Historical Years 2008 Through 2009
Witness: R. J. Alexander

FORECASTING MODEL: SMALL COMMERCIAL ENERGY

(1) LINE NO.	(2) YEAR	(3) MONTH	(4) CDHBD_04 (INPUT)	(5) CDHBD_05 (INPUT)	(6) CDHBD_06 (INPUT)	(7) CDHBD_07 (INPUT)	(8) CDHBD_08 (INPUT)	(9) CDHBD_09 (INPUT)	(10) CDHBD_10 (INPUT)	(11) CDHBD_11 (INPUT)
1	2008	JAN	0	0	0	0	0	0	0	0
2	2008	FEB	0	0	0	0	0	0	0	0
3	2008	MAR	0	0	0	0	0	0	0	0
4	2008	APR	43	0	0	0	0	0	0	0
5	2008	MAY	0	133	0	0	0	0	0	0
6	2008	JUN	0	0	318	0	0	0	0	0
7	2008	JUL	0	0	0	368	0	0	0	0
8	2008	AUG	0	0	0	0	387	0	0	0
9	2008	SEP	0	0	0	0	0	339	0	0
10	2008	OCT	0	0	0	0	0	0	182	0
11	2008	NOV	0	0	0	0	0	0	0	47
12	2008	DEC	0	0	0	0	0	0	0	0
13	2009	JAN	0	0	0	0	0	0	0	0
14	2009	FEB	0	0	0	0	0	0	0	0
15	2009	MAR	0	0	0	0	0	0	0	0
16	2009	APR	38	0	0	0	0	0	0	0
17	2009	MAY	0	142	0	0	0	0	0	0
18	2009	JUN	0	0	270	0	0	0	0	0
19	2009	JUL	0	0	0	382	0	0	0	0
20	2009	AUG	0	0	0	0	325	0	0	0
21	2009	SEP	0	0	0	0	0	270	0	0
22	2009	OCT	0	0	0	0	0	0	236	0
23	2009	NOV	0	0	0	0	0	0	0	69
24	2009	DEC	0	0	0	0	0	0	0	0

VARIABLE	DESCRIPTION
CDHBD_XX	Billing Cycle Small Commercial Cooling Degree Hours per Billing Day for Month XX (04=April, etc.)

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of Data Shown:
___ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
_X_ Historical Years 2010 Through 2011
Witness: R. J. Alexander

FORECASTING MODEL: SMALL COMMERCIAL ENERGY

(1) LINE NO.	(2) YEAR	(3) MONTH	(4) CDHBD_04 (INPUT)	(5) CDHBD_05 (INPUT)	(6) CDHBD_06 (INPUT)	(7) CDHBD_07 (INPUT)	(8) CDHBD_08 (INPUT)	(9) CDHBD_09 (INPUT)	(10) CDHBD_10 (INPUT)	(11) CDHBD_11 (INPUT)
1	2010	JAN	0	0	0	0	0	0	0	0
2	2010	FEB	0	0	0	0	0	0	0	0
3	2010	MAR	0	0	0	0	0	0	0	0
4	2010	APR	33	0	0	0	0	0	0	0
5	2010	MAY	0	133	0	0	0	0	0	0
6	2010	JUN	0	0	295	0	0	0	0	0
7	2010	JUL	0	0	0	369	0	0	0	0
8	2010	AUG	0	0	0	0	413	0	0	0
9	2010	SEP	0	0	0	0	0	340	0	0
10	2010	OCT	0	0	0	0	0	0	213	0
11	2010	NOV	0	0	0	0	0	0	0	94
12	2010	DEC	0	0	0	0	0	0	0	0
13	2011	JAN	0	0	0	0	0	0	0	0
14	2011	FEB	0	0	0	0	0	0	0	0
15	2011	MAR	0	0	0	0	0	0	0	0
16	2011	APR	89	0	0	0	0	0	0	0
17	2011	MAY	0	157	0	0	0	0	0	0
18	2011	JUN	0	0	312	0	0	0	0	0
19	2011	JUL	0	0	0	390	0	0	0	0
20	2011	AUG	0	0	0	0	388	0	0	0
21	2011	SEP	0	0	0	0	0	328	0	0
22	2011	OCT	0	0	0	0	0	0	161	0
23	2011	NOV	0	0	0	0	0	0	0	52
24	2011	DEC	0	0	0	0	0	0	0	0

VARIABLE	DESCRIPTION
CDHBD_XX	Billing Cycle Small Commercial Cooling Degree Hours per Billing Day for Month XX (04=April, etc.)

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of Data Shown:
___ Projected Test Year Ended 12/31/14
_X_ Prior Year Ended 12/31/13
_X_ Historical Year 2012
Witness: R. J. Alexander

FORECASTING MODEL: SMALL COMMERCIAL ENERGY

(1) LINE NO.	(2) YEAR	(3) MONTH	(4) CDHBD_04 (INPUT)	(5) CDHBD_05 (INPUT)	(6) CDHBD_06 (INPUT)	(7) CDHBD_07 (INPUT)	(8) CDHBD_08 (INPUT)	(9) CDHBD_09 (INPUT)	(10) CDHBD_10 (INPUT)	(11) CDHBD_11 (INPUT)
1	2012	JAN	0	0	0	0	0	0	0	0
2	2012	FEB	0	0	0	0	0	0	0	0
3	2012	MAR	0	0	0	0	0	0	0	0
4	2012	APR	104	0	0	0	0	0	0	0
5	2012	MAY	0	166	0	0	0	0	0	0
6	2012	JUN	0	0	298	0	0	0	0	0
7	2012	JUL	0	0	0	342	0	0	0	0
8	2012	AUG	0	0	0	0	353	0	0	0
9	2012	SEP	0	0	0	0	0	314	0	0
10	2012	OCT	0	0	0	0	0	0	192	0
11	2012	NOV	0	0	0	0	0	0	0	76
12	2012	DEC	0	0	0	0	0	0	0	0
13	2013	JAN	0	0	0	0	0	0	0	0
14	2013	FEB	0	0	0	0	0	0	0	0
15	2013	MAR	0	0	0	0	0	0	0	0
16	2013	APR	54	0	0	0	0	0	0	0
17	2013	MAY	0	139	0	0	0	0	0	0
18	2013	JUN	0	0	271	0	0	0	0	0
19	2013	JUL	0	0	0	350	0	0	0	0
20	2013	AUG	0	0	0	0	353	0	0	0
21	2013	SEP	0	0	0	0	0	321	0	0
22	2013	OCT	0	0	0	0	0	0	203	0
23	2013	NOV	0	0	0	0	0	0	0	76
24	2013	DEC	0	0	0	0	0	0	0	0

VARIABLE	DESCRIPTION
CDHBD_XX	Billing Cycle Small Commercial Cooling Degree Hours per Billing Day for Month XX (04=April, etc.)

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of Data Shown:
_X_ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
___ Historical Year 2012
Witness: R. J. Alexander

FORECASTING MODEL: SMALL COMMERCIAL ENERGY

(1) LINE NO.	(2) YEAR	(3) MONTH	(4) CDHBD_04 (INPUT)	(5) CDHBD_05 (INPUT)	(6) CDHBD_06 (INPUT)	(7) CDHBD_07 (INPUT)	(8) CDHBD_08 (INPUT)	(9) CDHBD_09 (INPUT)	(10) CDHBD_10 (INPUT)	(11) CDHBD_11 (INPUT)
1	2014	JAN	0	0	0	0	0	0	0	0
2	2014	FEB	0	0	0	0	0	0	0	0
3	2014	MAR	0	0	0	0	0	0	0	0
4	2014	APR	54	0	0	0	0	0	0	0
5	2014	MAY	0	139	0	0	0	0	0	0
6	2014	JUN	0	0	271	0	0	0	0	0
7	2014	JUL	0	0	0	350	0	0	0	0
8	2014	AUG	0	0	0	0	353	0	0	0
9	2014	SEP	0	0	0	0	0	321	0	0
10	2014	OCT	0	0	0	0	0	0	203	0
11	2014	NOV	0	0	0	0	0	0	0	76
12	2014	DEC	0	0	0	0	0	0	0	0

VARIABLE	DESCRIPTION
CDHBD_XX	Billing Cycle Small Commercial Cooling Degree Hours per Billing Day for Month XX (04=April, etc.)

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of Data Shown:
___ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
_X_ Historical Years 1992 Through 1993
Witness: R. J. Alexander

FORECASTING MODEL: LARGE COMMERCIAL ENERGY

(1) LINE NO.	(2) YEAR	(3) MONTH	(4) LgComSales (OUTPUT)	(5) LgComSales (INPUT)	(6) NonMfgEmp (INPUT)	(7) ComPrice (INPUT)	(8) Ivan (INPUT)	(9) DennisKatrina (INPUT)	(10) Isaac (INPUT)	(11) HDHBD_01 (INPUT)	(12) HDHBD_02 (INPUT)	(13) HDHBD_03 (INPUT)	(14) HDHBD_12 (INPUT)
1	1992	NOV		495.233	229.070	7.334	0	0	0	0	0	0	0
2	1992	DEC	456.266	440.172	229.700	7.344	0	0	0	0	0	0	77
3	1993	JAN	425.035	439.909	230.400	7.354	0	0	0	39	0	0	0
4	1993	FEB	461.435	453.491	231.210	7.378	0	0	0	0	82	0	0
5	1993	MAR	460.946	458.280	232.170	7.403	0	0	0	0	0	80	0
6	1993	APR	464.560	466.691	233.120	7.437	0	0	0	0	0	0	0
7	1993	MAY	507.060	479.496	233.750	7.432	0	0	0	0	0	0	0
8	1993	JUN	594.121	593.078	233.930	7.442	0	0	0	0	0	0	0
9	1993	JUL	653.597	673.490	233.970	7.452	0	0	0	0	0	0	0
10	1993	AUG	678.301	677.392	234.300	7.456	0	0	0	0	0	0	0
11	1993	SEP	656.753	651.199	235.190	7.428	0	0	0	0	0	0	0
12	1993	OCT	592.106	589.670	236.430	7.421	0	0	0	0	0	0	0
13	1993	NOV	497.632	496.734	237.640	7.373	0	0	0	0	0	0	0
14	1993	DEC	460.091	446.178	238.550	7.329	0	0	0	0	0	0	73

VARIABLE	DESCRIPTION
LgComSales	Billing Cycle Large Commercial kWh per Customer per Billing Day
NonMfgEmp	Non-manufacturing Employment (000's)
ComPrice	12-Month Average of Real Commercial Price (cents per kWh)
Ivan	Binary Variable for Hurricane Ivan September 2004
DennisKatrina	Binary Variable for Hurricanes Dennis and Katrina July-September 2005
Isaac	Binary Variable for Hurricane Isaac August-September 2012
HDHBD_XX	Billing Cycle Large Commercial Heating Degree Hours per Billing Day for Month XX (01=January, etc.)

Supporting Schedules: Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of Data Shown:
___ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
_X_ Historical Years 1994 Through 1995
Witness: R. J. Alexander

FORECASTING MODEL: LARGE COMMERCIAL ENERGY

(1) LINE NO.	(2) YEAR	(3) MONTH	(4) LgComSales (OUTPUT)	(5) LgComSales (INPUT)	(6) NonMfgEmp (INPUT)	(7) ComPrice (INPUT)	(8) Ivan (INPUT)	(9) DennisKatrina (INPUT)	(10) Isaac (INPUT)	(11) HDHBD_01 (INPUT)	(12) HDHBD_02 (INPUT)	(13) HDHBD_03 (INPUT)	(14) HDHBD_12 (INPUT)
1	1994	JAN	475.681	470.757	239.270	7.284	0	0	0	177	0	0	0
2	1994	FEB	480.155	474.000	239.960	7.232	0	0	0	0	143	0	0
3	1994	MAR	468.184	459.110	240.780	7.195	0	0	0	0	0	49	0
4	1994	APR	489.508	480.179	241.730	7.154	0	0	0	0	0	0	0
5	1994	MAY	548.334	553.258	242.680	7.145	0	0	0	0	0	0	0
6	1994	JUN	611.502	611.803	243.540	7.119	0	0	0	0	0	0	0
7	1994	JUL	645.440	645.160	244.280	7.110	0	0	0	0	0	0	0
8	1994	AUG	643.067	653.363	244.920	7.110	0	0	0	0	0	0	0
9	1994	SEP	642.404	622.056	245.420	7.099	0	0	0	0	0	0	0
10	1994	OCT	582.773	582.291	245.840	7.110	0	0	0	0	0	0	0
11	1994	NOV	507.654	501.426	246.210	7.145	0	0	0	0	0	0	0
12	1994	DEC	457.993	467.259	246.550	7.173	0	0	0	0	0	0	35
13	1995	JAN	457.690	443.647	246.810	7.196	0	0	0	92	0	0	0
14	1995	FEB	476.745	469.856	246.920	7.242	0	0	0	0	115	0	0
15	1995	MAR	470.013	479.518	246.870	7.264	0	0	0	0	0	54	0
16	1995	APR	491.755	503.896	246.880	7.279	0	0	0	0	0	0	0
17	1995	MAY	547.718	533.885	247.250	7.284	0	0	0	0	0	0	0
18	1995	JUN	629.576	666.678	248.090	7.301	0	0	0	0	0	0	0
19	1995	JUL	668.615	656.600	249.040	7.302	0	0	0	0	0	0	0
20	1995	AUG	680.002	697.708	249.580	7.309	0	0	0	0	0	0	0
21	1995	SEP	685.953	684.014	249.400	7.321	0	0	0	0	0	0	0
22	1995	OCT	612.595	606.464	248.960	7.318	0	0	0	0	0	0	0
23	1995	NOV	506.197	497.287	248.940	7.309	0	0	0	0	0	0	0
24	1995	DEC	469.348	462.105	249.770	7.309	0	0	0	0	0	0	89

VARIABLE	DESCRIPTION
LgComSales	Billing Cycle Large Commercial kWh per Customer per Billing Day
NonMfgEmp	Non-manufacturing Employment (000's)
ComPrice	12-Month Average of Real Commercial Price (cents per kWh)
Ivan	Binary Variable for Hurricane Ivan September 2004
DennisKatrina	Binary Variable for Hurricanes Dennis and Katrina July-September 2005
Isaac	Binary Variable for Hurricane Isaac August-September 2012
HDHBD_XX	Billing Cycle Large Commercial Heating Degree Hours per Billing Day for Month XX (01=January, etc.)

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of Data Shown:
___ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
_X_ Historical Years 1996 Through 1997
Witness: R. J. Alexander

FORECASTING MODEL: LARGE COMMERCIAL ENERGY

(1) LINE NO.	(2) YEAR	(3) MONTH	(4) LgComSales (OUTPUT)	(5) LgComSales (INPUT)	(6) NonMfgEmp (INPUT)	(7) ComPrice (INPUT)	(8) Ivan (INPUT)	(9) DennisKatrina (INPUT)	(10) Isaac (INPUT)	(11) HDHBD_01 (INPUT)	(12) HDHBD_02 (INPUT)	(13) HDHBD_03 (INPUT)	(14) HDHBD_12 (INPUT)
1	1996	JAN	489.644	506.950	251.130	7.310	0	0	0	196	0	0	0
2	1996	FEB	499.409	499.576	252.380	7.273	0	0	0	0	178	0	0
3	1996	MAR	488.423	482.324	253.160	7.267	0	0	0	0	0	104	0
4	1996	APR	474.962	486.491	253.590	7.266	0	0	0	0	0	0	0
5	1996	MAY	547.863	538.887	253.950	7.255	0	0	0	0	0	0	0
6	1996	JUN	643.597	643.094	254.470	7.239	0	0	0	0	0	0	0
7	1996	JUL	687.509	694.852	255.210	7.226	0	0	0	0	0	0	0
8	1996	AUG	688.952	664.988	256.190	7.203	0	0	0	0	0	0	0
9	1996	SEP	658.847	663.785	257.290	7.194	0	0	0	0	0	0	0
10	1996	OCT	594.430	616.596	258.270	7.172	0	0	0	0	0	0	0
11	1996	NOV	525.587	505.779	258.800	7.161	0	0	0	0	0	0	0
12	1996	DEC	470.324	474.078	258.690	7.159	0	0	0	0	0	0	64
13	1997	JAN	474.186	481.545	258.300	7.148	0	0	0	123	0	0	0
14	1997	FEB	486.973	435.402	258.160	7.152	0	0	0	0	111	0	0
15	1997	MAR	477.846	484.228	258.560	7.133	0	0	0	0	0	28	0
16	1997	APR	508.244	508.114	259.320	7.108	0	0	0	0	0	0	0
17	1997	MAY	534.241	509.069	260.060	7.070	0	0	0	0	0	0	0
18	1997	JUN	607.857	606.004	260.510	7.044	0	0	0	0	0	0	0
19	1997	JUL	673.118	663.270	260.770	7.028	0	0	0	0	0	0	0
20	1997	AUG	677.441	662.936	261.070	7.014	0	0	0	0	0	0	0
21	1997	SEP	674.340	689.237	261.570	6.990	0	0	0	0	0	0	0
22	1997	OCT	625.208	651.796	262.200	6.966	0	0	0	0	0	0	0
23	1997	NOV	503.733	494.081	262.820	6.929	0	0	0	0	0	0	0
24	1997	DEC	484.152	498.549	263.340	6.894	0	0	0	0	0	0	93

VARIABLE	DESCRIPTION
LgComSales	Billing Cycle Large Commercial kWh per Customer per Billing Day
NonMfgEmp	Non-manufacturing Employment (000's)
ComPrice	12-Month Average of Real Commercial Price (cents per kWh)
Ivan	Binary Variable for Hurricane Ivan September 2004
DennisKatrina	Binary Variable for Hurricanes Dennis and Katrina July-September 2005
Isaac	Binary Variable for Hurricane Isaac August-September 2012
HDHBD_XX	Billing Cycle Large Commercial Heating Degree Hours per Billing Day for Month XX (01=January, etc.)

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of Data Shown:
___ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
_X_ Historical Years 1998 Through 1999
Witness: R. J. Alexander

FORECASTING MODEL: LARGE COMMERCIAL ENERGY

(1) LINE NO.	(2) YEAR	(3) MONTH	(4) LgComSales (OUTPUT)	(5) LgComSales (INPUT)	(6) NonMfgEmp (INPUT)	(7) ComPrice (INPUT)	(8) Ivan (INPUT)	(9) DennisKatrina (INPUT)	(10) Isaac (INPUT)	(11) HDHBD_01 (INPUT)	(12) HDHBD_02 (INPUT)	(13) HDHBD_03 (INPUT)	(14) HDHBD_12 (INPUT)
1	1998	JAN	478.981	448.054	263.870	6.842	0	0	0	110	0	0	0
2	1998	FEB	485.425	470.469	264.490	6.822	0	0	0	0	96	0	0
3	1998	MAR	485.360	483.467	265.290	6.795	0	0	0	0	0	74	0
4	1998	APR	504.543	510.252	266.100	6.756	0	0	0	0	0	0	0
5	1998	MAY	567.818	557.626	266.620	6.697	0	0	0	0	0	0	0
6	1998	JUN	678.665	701.781	266.720	6.625	0	0	0	0	0	0	0
7	1998	JUL	717.759	732.236	266.650	6.552	0	0	0	0	0	0	0
8	1998	AUG	699.439	705.922	266.800	6.497	0	0	0	0	0	0	0
9	1998	SEP	683.891	667.334	267.410	6.438	0	0	0	0	0	0	0
10	1998	OCT	633.078	686.852	268.140	6.365	0	0	0	0	0	0	0
11	1998	NOV	546.888	550.328	268.500	6.344	0	0	0	0	0	0	0
12	1998	DEC	481.616	493.551	268.200	6.249	0	0	0	0	0	0	19
13	1999	JAN	498.047	492.722	267.540	6.196	0	0	0	139	0	0	0
14	1999	FEB	488.176	507.196	267.070	6.136	0	0	0	0	51	0	0
15	1999	MAR	498.914	489.964	267.070	6.072	0	0	0	0	0	52	0
16	1999	APR	523.514	516.714	267.430	6.028	0	0	0	0	0	0	0
17	1999	MAY	573.154	588.821	267.870	6.020	0	0	0	0	0	0	0
18	1999	JUN	640.844	646.509	268.180	6.017	0	0	0	0	0	0	0
19	1999	JUL	683.915	703.658	268.380	6.018	0	0	0	0	0	0	0
20	1999	AUG	718.157	724.733	268.600	6.010	0	0	0	0	0	0	0
21	1999	SEP	691.402	708.330	268.900	6.007	0	0	0	0	0	0	0
22	1999	OCT	616.662	606.236	269.220	6.029	0	0	0	0	0	0	0
23	1999	NOV	525.927	531.302	269.440	6.000	0	0	0	0	0	0	0
24	1999	DEC	492.315	490.525	269.540	6.011	0	0	0	0	0	0	58

VARIABLE	DESCRIPTION
LgComSales	Billing Cycle Large Commercial kWh per Customer per Billing Day
NonMfgEmp	Non-manufacturing Employment (000's)
ComPrice	12-Month Average of Real Commercial Price (cents per kWh)
Ivan	Binary Variable for Hurricane Ivan September 2004
DennisKatrina	Binary Variable for Hurricanes Dennis and Katrina July-September 2005
Isaac	Binary Variable for Hurricane Isaac August-September 2012
HDHBD_XX	Billing Cycle Large Commercial Heating Degree Hours per Billing Day for Month XX (01=January, etc.)

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of Data Shown:
___ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
_X_ Historical Years 2000 Through 2001
Witness: R. J. Alexander

FORECASTING MODEL: LARGE COMMERCIAL ENERGY

(1) LINE NO.	(2) YEAR	(3) MONTH	(4) LgComSales (OUTPUT)	(5) LgComSales (INPUT)	(6) NonMfgEmp (INPUT)	(7) ComPrice (INPUT)	(8) Ivan (INPUT)	(9) DennisKatrina (INPUT)	(10) Isaac (INPUT)	(11) HDHBD_01 (INPUT)	(12) HDHBD_02 (INPUT)	(13) HDHBD_03 (INPUT)	(14) HDHBD_12 (INPUT)
1	2000	JAN	487.687	475.922	269.660	6.009	0	0	0	103	0	0	0
2	2000	FEB	510.400	516.426	270.030	6.022	0	0	0	0	136	0	0
3	2000	MAR	501.242	500.651	270.780	6.036	0	0	0	0	0	26	0
4	2000	APR	520.628	525.333	271.730	6.044	0	0	0	0	0	0	0
5	2000	MAY	570.609	559.407	272.570	6.060	0	0	0	0	0	0	0
6	2000	JUN	665.804	677.809	273.100	6.072	0	0	0	0	0	0	0
7	2000	JUL	716.249	713.252	273.260	6.086	0	0	0	0	0	0	0
8	2000	AUG	718.425	725.762	273.100	6.097	0	0	0	0	0	0	0
9	2000	SEP	691.711	704.794	272.720	6.104	0	0	0	0	0	0	0
10	2000	OCT	602.449	593.807	272.440	6.106	0	0	0	0	0	0	0
11	2000	NOV	541.730	543.272	272.630	6.120	0	0	0	0	0	0	0
12	2000	DEC	507.516	498.910	273.480	6.138	0	0	0	0	0	0	128
13	2001	JAN	535.560	532.082	274.680	6.159	0	0	0	252	0	0	0
14	2001	FEB	508.636	507.558	275.630	6.135	0	0	0	0	115	0	0
15	2001	MAR	501.047	500.678	276.070	6.118	0	0	0	0	0	38	0
16	2001	APR	521.463	519.254	276.160	6.098	0	0	0	0	0	0	0
17	2001	MAY	567.674	564.915	276.230	6.076	0	0	0	0	0	0	0
18	2001	JUN	653.398	650.221	276.500	6.054	0	0	0	0	0	0	0
19	2001	JUL	681.348	683.424	276.870	6.033	0	0	0	0	0	0	0
20	2001	AUG	694.507	707.648	277.130	6.009	0	0	0	0	0	0	0
21	2001	SEP	676.930	656.750	277.130	5.988	0	0	0	0	0	0	0
22	2001	OCT	592.190	580.486	276.980	5.971	0	0	0	0	0	0	0
23	2001	NOV	532.539	516.405	276.860	5.948	0	0	0	0	0	0	0
24	2001	DEC	487.781	491.620	276.910	5.925	0	0	0	0	0	0	27

VARIABLE	DESCRIPTION
LgComSales	Billing Cycle Large Commercial kWh per Customer per Billing Day
NonMfgEmp	Non-manufacturing Employment (000's)
ComPrice	12-Month Average of Real Commercial Price (cents per kWh)
Ivan	Binary Variable for Hurricane Ivan September 2004
DennisKatrina	Binary Variable for Hurricanes Dennis and Katrina July-September 2005
Isaac	Binary Variable for Hurricane Isaac August-September 2012
HDHBD_XX	Billing Cycle Large Commercial Heating Degree Hours per Billing Day for Month XX (01=January, etc.)

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of Data Shown:
___ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
_X_ Historical Years 2002 Through 2003
Witness: R. J. Alexander

FORECASTING MODEL: LARGE COMMERCIAL ENERGY

(1) LINE NO.	(2) YEAR	(3) MONTH	(4) LgComSales (OUTPUT)	(5) LgComSales (INPUT)	(6) NonMfgEmp (INPUT)	(7) ComPrice (INPUT)	(8) Ivan (INPUT)	(9) DennisKatrina (INPUT)	(10) Isaac (INPUT)	(11) HDHBD_01 (INPUT)	(12) HDHBD_02 (INPUT)	(13) HDHBD_03 (INPUT)	(14) HDHBD_12 (INPUT)
1	2002	JAN	514.429	507.764	277.170	5.898	0	0	0	167	0	0	0
2	2002	FEB	505.680	504.289	277.610	5.913	0	0	0	0	88	0	0
3	2002	MAR	516.530	504.685	278.200	5.923	0	0	0	0	0	112	0
4	2002	APR	528.987	528.218	278.810	5.945	0	0	0	0	0	0	0
5	2002	MAY	608.227	637.842	279.230	5.960	0	0	0	0	0	0	0
6	2002	JUN	652.129	624.943	279.370	5.966	0	0	0	0	0	0	0
7	2002	JUL	681.097	687.615	279.410	6.018	0	0	0	0	0	0	0
8	2002	AUG	699.081	704.823	279.690	6.072	0	0	0	0	0	0	0
9	2002	SEP	691.613	688.601	280.370	6.124	0	0	0	0	0	0	0
10	2002	OCT	650.563	672.983	281.260	6.171	0	0	0	0	0	0	0
11	2002	NOV	541.765	547.251	282.020	6.212	0	0	0	0	0	0	0
12	2002	DEC	508.454	499.954	282.440	6.267	0	0	0	0	0	0	107
13	2003	JAN	511.544	508.062	282.640	6.330	0	0	0	167	0	0	0
14	2003	FEB	518.776	521.619	282.810	6.373	0	0	0	0	150	0	0
15	2003	MAR	499.710	510.495	283.150	6.422	0	0	0	0	0	32	0
16	2003	APR	528.189	530.410	283.830	6.461	0	0	0	0	0	0	0
17	2003	MAY	596.047	615.877	284.960	6.506	0	0	0	0	0	0	0
18	2003	JUN	657.969	678.608	286.560	6.558	0	0	0	0	0	0	0
19	2003	JUL	676.346	689.025	288.320	6.566	0	0	0	0	0	0	0
20	2003	AUG	685.643	708.621	289.810	6.579	0	0	0	0	0	0	0
21	2003	SEP	684.299	702.135	290.730	6.587	0	0	0	0	0	0	0
22	2003	OCT	608.199	616.515	291.400	6.597	0	0	0	0	0	0	0
23	2003	NOV	552.288	556.472	292.300	6.615	0	0	0	0	0	0	0
24	2003	DEC	509.560	519.796	293.700	6.624	0	0	0	0	0	0	101

VARIABLE	DESCRIPTION
LgComSales	Billing Cycle Large Commercial kWh per Customer per Billing Day
NonMfgEmp	Non-manufacturing Employment (000's)
ComPrice	12-Month Average of Real Commercial Price (cents per kWh)
Ivan	Binary Variable for Hurricane Ivan September 2004
DennisKatrina	Binary Variable for Hurricanes Dennis and Katrina July-September 2005
Isaac	Binary Variable for Hurricane Isaac August-September 2012
HDHBD_XX	Billing Cycle Large Commercial Heating Degree Hours per Billing Day for Month XX (01=January, etc.)

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of Data Shown:
___ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
_X_ Historical Years 2004 Through 2005
Witness: R. J. Alexander

FORECASTING MODEL: LARGE COMMERCIAL ENERGY

(1) LINE NO.	(2) YEAR	(3) MONTH	(4) LgComSales (OUTPUT)	(5) LgComSales (INPUT)	(6) NonMfgEmp (INPUT)	(7) ComPrice (INPUT)	(8) Ivan (INPUT)	(9) DennisKatrina (INPUT)	(10) Isaac (INPUT)	(11) HDHBD_01 (INPUT)	(12) HDHBD_02 (INPUT)	(13) HDHBD_03 (INPUT)	(14) HDHBD_12 (INPUT)
1	2004	JAN	514.082	498.563	295.430	6.628	0	0	0	152	0	0	0
2	2004	FEB	518.680	524.575	297.000	6.643	0	0	0	0	132	0	0
3	2004	MAR	512.057	511.051	298.210	6.647	0	0	0	0	0	61	0
4	2004	APR	524.919	522.610	299.140	6.657	0	0	0	0	0	0	0
5	2004	MAY	573.880	570.686	299.990	6.660	0	0	0	0	0	0	0
6	2004	JUN	665.568	671.175	300.840	6.673	0	0	0	0	0	0	0
7	2004	JUL	697.302	708.656	301.530	6.681	0	0	0	0	0	0	0
8	2004	AUG	704.637	705.369	301.790	6.683	0	0	0	0	0	0	0
9	2004	SEP	580.739	576.317	301.490	6.688	1	0	0	0	0	0	0
10	2004	OCT	652.378	624.166	301.110	6.701	0	0	0	0	0	0	0
11	2004	NOV	567.730	573.734	301.230	6.726	0	0	0	0	0	0	0
12	2004	DEC	504.853	524.115	302.260	6.715	0	0	0	0	0	0	62
13	2005	JAN	509.432	506.069	303.920	6.713	0	0	0	120	0	0	0
14	2005	FEB	515.920	514.762	305.570	6.733	0	0	0	0	94	0	0
15	2005	MAR	510.391	506.885	306.920	6.759	0	0	0	0	0	48	0
16	2005	APR	522.129	518.148	308.000	6.783	0	0	0	0	0	0	0
17	2005	MAY	561.501	552.892	308.900	6.824	0	0	0	0	0	0	0
18	2005	JUN	661.634	652.712	309.760	6.872	0	0	0	0	0	0	0
19	2005	JUL	685.299	686.762	310.790	6.918	0	1	0	0	0	0	0
20	2005	AUG	692.442	689.058	312.230	6.970	0	1	0	0	0	0	0
21	2005	SEP	697.644	696.782	314.110	7.018	0	1	0	0	0	0	0
22	2005	OCT	676.103	662.593	316.140	7.061	0	0	0	0	0	0	0
23	2005	NOV	548.773	550.257	317.860	7.075	0	0	0	0	0	0	0
24	2005	DEC	512.631	517.952	318.940	7.126	0	0	0	0	0	0	74

VARIABLE	DESCRIPTION
LgComSales	Billing Cycle Large Commercial kWh per Customer per Billing Day
NonMfgEmp	Non-manufacturing Employment (000's)
ComPrice	12-Month Average of Real Commercial Price (cents per kWh)
Ivan	Binary Variable for Hurricane Ivan September 2004
DennisKatrina	Binary Variable for Hurricanes Dennis and Katrina July-September 2005
Isaac	Binary Variable for Hurricane Isaac August-September 2012
HDHBD_XX	Billing Cycle Large Commercial Heating Degree Hours per Billing Day for Month XX (01=January, etc.)

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of Data Shown:
___ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
_X_ Historical Years 2006 Through 2007
Witness: R. J. Alexander

FORECASTING MODEL: LARGE COMMERCIAL ENERGY

(1) LINE NO.	(2) YEAR	(3) MONTH	(4) LgComSales (OUTPUT)	(5) LgComSales (INPUT)	(6) NonMfgEmp (INPUT)	(7) ComPrice (INPUT)	(8) Ivan (INPUT)	(9) DennisKatrina (INPUT)	(10) Isaac (INPUT)	(11) HDHBD_01 (INPUT)	(12) HDHBD_02 (INPUT)	(13) HDHBD_03 (INPUT)	(14) HDHBD_12 (INPUT)
1	2006	JAN	500.930	496.140	319.410	7.171	0	0	0	87	0	0	0
2	2006	FEB	512.889	499.367	319.420	7.208	0	0	0	0	71	0	0
3	2006	MAR	516.252	510.465	319.140	7.245	0	0	0	0	0	39	0
4	2006	APR	551.176	529.741	318.760	7.279	0	0	0	0	0	0	0
5	2006	MAY	599.972	603.740	318.510	7.301	0	0	0	0	0	0	0
6	2006	JUN	684.252	672.802	318.570	7.305	0	0	0	0	0	0	0
7	2006	JUL	727.306	711.349	318.890	7.320	0	0	0	0	0	0	0
8	2006	AUG	716.825	727.370	319.400	7.329	0	0	0	0	0	0	0
9	2006	SEP	702.296	707.687	319.960	7.341	0	0	0	0	0	0	0
10	2006	OCT	638.758	618.651	320.460	7.355	0	0	0	0	0	0	0
11	2006	NOV	532.435	545.450	320.760	7.378	0	0	0	0	0	0	0
12	2006	DEC	516.915	511.869	320.780	7.401	0	0	0	0	0	0	96
13	2007	JAN	492.262	508.589	320.580	7.422	0	0	0	71	0	0	0
14	2007	FEB	531.039	516.950	320.330	7.472	0	0	0	0	144	0	0
15	2007	MAR	515.032	511.285	320.110	7.523	0	0	0	0	0	62	0
16	2007	APR	536.172	526.950	319.890	7.577	0	0	0	0	0	0	0
17	2007	MAY	586.649	585.633	319.640	7.630	0	0	0	0	0	0	0
18	2007	JUN	654.277	638.917	319.300	7.693	0	0	0	0	0	0	0
19	2007	JUL	701.546	704.852	318.780	7.754	0	0	0	0	0	0	0
20	2007	AUG	725.704	721.664	317.990	7.813	0	0	0	0	0	0	0
21	2007	SEP	709.296	724.726	316.940	7.872	0	0	0	0	0	0	0
22	2007	OCT	655.774	653.176	315.840	7.928	0	0	0	0	0	0	0
23	2007	NOV	533.137	542.103	314.960	7.981	0	0	0	0	0	0	0
24	2007	DEC	495.503	496.390	314.470	8.037	0	0	0	0	0	0	49

VARIABLE	DESCRIPTION
LgComSales	Billing Cycle Large Commercial kWh per Customer per Billing Day
NonMfgEmp	Non-manufacturing Employment (000's)
ComPrice	12-Month Average of Real Commercial Price (cents per kWh)
Ivan	Binary Variable for Hurricane Ivan September 2004
DennisKatrina	Binary Variable for Hurricanes Dennis and Katrina July-September 2005
Isaac	Binary Variable for Hurricane Isaac August-September 2012
HDHBD_XX	Billing Cycle Large Commercial Heating Degree Hours per Billing Day for Month XX (01=January, etc.)

Supporting Schedules: Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of Data Shown:
___ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
_X_ Historical Years 2008 Through 2009
Witness: R. J. Alexander

FORECASTING MODEL: LARGE COMMERCIAL ENERGY

(1) LINE NO.	(2) YEAR	(3) MONTH	(4) LgComSales (OUTPUT)	(5) LgComSales (INPUT)	(6) NonMfgEmp (INPUT)	(7) ComPrice (INPUT)	(8) Ivan (INPUT)	(9) DennisKatrina (INPUT)	(10) Isaac (INPUT)	(11) HDHBD_01 (INPUT)	(12) HDHBD_02 (INPUT)	(13) HDHBD_03 (INPUT)	(14) HDHBD_12 (INPUT)
1	2008	JAN	495.441	513.018	314.070	8.091	0	0	0	115	0	0	0
2	2008	FEB	511.310	526.423	313.380	8.084	0	0	0	0	108	0	0
3	2008	MAR	505.733	502.078	312.150	8.072	0	0	0	0	0	62	0
4	2008	APR	518.018	533.127	310.610	8.063	0	0	0	0	0	0	0
5	2008	MAY	574.010	569.245	309.190	8.050	0	0	0	0	0	0	0
6	2008	JUN	677.523	660.033	308.170	8.039	0	0	0	0	0	0	0
7	2008	JUL	702.684	688.597	307.340	8.023	0	0	0	0	0	0	0
8	2008	AUG	716.873	685.393	306.340	8.012	0	0	0	0	0	0	0
9	2008	SEP	688.218	682.731	304.960	7.999	0	0	0	0	0	0	0
10	2008	OCT	608.059	598.943	303.330	8.067	0	0	0	0	0	0	0
11	2008	NOV	508.861	523.733	301.690	8.141	0	0	0	0	0	0	0
12	2008	DEC	494.227	485.099	300.230	8.227	0	0	0	0	0	0	92
13	2009	JAN	473.455	479.376	299.000	8.310	0	0	0	88	0	0	0
14	2009	FEB	502.359	496.593	298.060	8.461	0	0	0	0	137	0	0
15	2009	MAR	490.097	501.218	297.320	8.618	0	0	0	0	0	64	0
16	2009	APR	502.476	504.807	296.670	8.774	0	0	0	0	0	0	0
17	2009	MAY	559.057	555.296	295.980	8.933	0	0	0	0	0	0	0
18	2009	JUN	635.068	636.408	295.200	9.089	0	0	0	0	0	0	0
19	2009	JUL	690.147	690.965	294.430	9.254	0	0	0	0	0	0	0
20	2009	AUG	664.935	659.904	293.840	9.400	0	0	0	0	0	0	0
21	2009	SEP	634.016	631.432	293.580	9.550	0	0	0	0	0	0	0
22	2009	OCT	613.899	624.820	293.530	9.621	0	0	0	0	0	0	0
23	2009	NOV	501.370	510.467	293.500	9.680	0	0	0	0	0	0	0
24	2009	DEC	469.546	473.569	293.420	9.739	0	0	0	0	0	0	80

VARIABLE	DESCRIPTION
LgComSales	Billing Cycle Large Commercial kWh per Customer per Billing Day
NonMfgEmp	Non-manufacturing Employment (000's)
ComPrice	12-Month Average of Real Commercial Price (cents per kWh)
Ivan	Binary Variable for Hurricane Ivan September 2004
DennisKatrina	Binary Variable for Hurricanes Dennis and Katrina July-September 2005
Isaac	Binary Variable for Hurricane Isaac August-September 2012
HDHBD_XX	Billing Cycle Large Commercial Heating Degree Hours per Billing Day for Month XX (01=January, etc.)

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of Data Shown:
___ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
_X_ Historical Years 2010 Through 2011
Witness: R. J. Alexander

FORECASTING MODEL: LARGE COMMERCIAL ENERGY

(1) LINE NO.	(2) YEAR	(3) MONTH	(4) LgComSales (OUTPUT)	(5) LgComSales (INPUT)	(6) NonMfgEmp (INPUT)	(7) ComPrice (INPUT)	(8) Ivan (INPUT)	(9) DennisKatrina (INPUT)	(10) Isaac (INPUT)	(11) HDHBD_01 (INPUT)	(12) HDHBD_02 (INPUT)	(13) HDHBD_03 (INPUT)	(14) HDHBD_12 (INPUT)
1	2010	JAN	497.637	508.382	293.400	9.793	0	0	0	222	0	0	0
2	2010	FEB	494.715	514.447	293.650	9.805	0	0	0	0	177	0	0
3	2010	MAR	486.123	505.455	294.300	9.812	0	0	0	0	0	143	0
4	2010	APR	481.182	485.071	295.280	9.818	0	0	0	0	0	0	0
5	2010	MAY	544.724	567.849	296.400	9.826	0	0	0	0	0	0	0
6	2010	JUN	643.718	644.134	297.500	9.831	0	0	0	0	0	0	0
7	2010	JUL	680.110	681.273	298.380	9.830	0	0	0	0	0	0	0
8	2010	AUG	706.799	705.268	298.870	9.849	0	0	0	0	0	0	0
9	2010	SEP	668.989	678.391	298.900	9.862	0	0	0	0	0	0	0
10	2010	OCT	602.036	593.701	298.750	9.873	0	0	0	0	0	0	0
11	2010	NOV	513.691	520.081	298.820	9.894	0	0	0	0	0	0	0
12	2010	DEC	480.432	484.840	299.350	9.901	0	0	0	0	0	0	127
13	2011	JAN	490.029	507.226	300.170	9.922	0	0	0	190	0	0	0
14	2011	FEB	495.967	527.006	300.880	9.879	0	0	0	0	163	0	0
15	2011	MAR	483.507	479.249	301.310	9.836	0	0	0	0	0	46	0
16	2011	APR	516.261	522.458	301.570	9.798	0	0	0	0	0	0	0
17	2011	MAY	559.618	563.336	301.860	9.757	0	0	0	0	0	0	0
18	2011	JUN	651.272	653.400	302.280	9.710	0	0	0	0	0	0	0
19	2011	JUL	694.648	674.642	302.640	9.668	0	0	0	0	0	0	0
20	2011	AUG	695.918	681.984	302.600	9.625	0	0	0	0	0	0	0
21	2011	SEP	664.214	651.958	302.000	9.585	0	0	0	0	0	0	0
22	2011	OCT	576.180	572.784	301.140	9.554	0	0	0	0	0	0	0
23	2011	NOV	496.457	485.918	300.500	9.540	0	0	0	0	0	0	0
24	2011	DEC	469.392	481.127	300.330	9.530	0	0	0	0	0	0	64

VARIABLE	DESCRIPTION
LgComSales	Billing Cycle Large Commercial kWh per Customer per Billing Day
NonMfgEmp	Non-manufacturing Employment (000's)
ComPrice	12-Month Average of Real Commercial Price (cents per kWh)
Ivan	Binary Variable for Hurricane Ivan September 2004
DennisKatrina	Binary Variable for Hurricanes Dennis and Katrina July-September 2005
Isaac	Binary Variable for Hurricane Isaac August-September 2012
HDHBD_XX	Billing Cycle Large Commercial Heating Degree Hours per Billing Day for Month XX (01=January, etc.)

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of Data Shown:
___ Projected Test Year Ended 12/31/14
_X_ Prior Year Ended 12/31/13
_X_ Historical Year 2012
Witness: R. J. Alexander

FORECASTING MODEL: LARGE COMMERCIAL ENERGY

(1) LINE NO.	(2) YEAR	(3) MONTH	(4) LgComSales (OUTPUT)	(5) LgComSales (INPUT)	(6) NonMfgEmp (INPUT)	(7) ComPrice (INPUT)	(8) Ivan (INPUT)	(9) DennisKatrina (INPUT)	(10) Isaac (INPUT)	(11) HDHBD_01 (INPUT)	(12) HDHBD_02 (INPUT)	(13) HDHBD_03 (INPUT)	(14) HDHBD_12 (INPUT)
1	2012	JAN	455.355	450.641	300.340	9.510	0	0	0	64	0	0	0
2	2012	FEB	469.277	483.187	300.030	9.506	0	0	0	0	50	0	0
3	2012	MAR	481.143	488.416	299.150	9.524	0	0	0	0	0	20	0
4	2012	APR	528.707	530.616	298.040	9.499	0	0	0	0	0	0	0
5	2012	MAY	565.279	554.503	297.280	9.471	0	0	0	0	0	0	0
6	2012	JUN	643.890	617.944	297.270	9.462	0	0	0	0	0	0	0
7	2012	JUL	666.107	645.507	297.800	9.444	0	0	0	0	0	0	0
8	2012	AUG	649.847	654.599	298.480	9.359	0	0	1	0	0	0	0
9	2012	SEP	634.480	623.902	298.990	9.273	0	0	1	0	0	0	0
10	2012	OCT	599.287	572.693	299.290	9.178	0	0	0	0	0	0	0
11	2012	NOV	511.605		299.470	9.064	0	0	0	0	0	0	0
12	2012	DEC	479.297		299.570	8.949	0	0	0	0	0	0	76
13	2013	JAN	483.474		299.680	8.837	0	0	0	134	0	0	0
14	2013	FEB	494.606		299.840	8.743	0	0	0	0	117	0	0
15	2013	MAR	490.965		300.120	8.630	0	0	0	0	0	60	0
16	2013	APR	510.144		300.500	8.553	0	0	0	0	0	0	0
17	2013	MAY	564.149		300.950	8.482	0	0	0	0	0	0	0
18	2013	JUN	646.483		301.430	8.398	0	0	0	0	0	0	0
19	2013	JUL	689.920		301.950	8.321	0	0	0	0	0	0	0
20	2013	AUG	696.789		302.520	8.308	0	0	0	0	0	0	0
21	2013	SEP	680.038		303.110	8.296	0	0	0	0	0	0	0
22	2013	OCT	618.394		303.720	8.300	0	0	0	0	0	0	0
23	2013	NOV	527.852		304.300	8.303	0	0	0	0	0	0	0
24	2013	DEC	490.718		304.830	8.306	0	0	0	0	0	0	76

VARIABLE	DESCRIPTION
LgComSales	Billing Cycle Large Commercial kWh per Customer per Billing Day
NonMfgEmp	Non-manufacturing Employment (000's)
ComPrice	12-Month Average of Real Commercial Price (cents per kWh)
Ivan	Binary Variable for Hurricane Ivan September 2004
DennisKatrina	Binary Variable for Hurricanes Dennis and Katrina July-September 2005
Isaac	Binary Variable for Hurricane Isaac August-September 2012
HDHBD_XX	Billing Cycle Large Commercial Heating Degree Hours per Billing Day for Month XX (01=January, etc.)

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of Data Shown:
X Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
___ Historical Year 2012
Witness: R. J. Alexander

FORECASTING MODEL: LARGE COMMERCIAL ENERGY

(1) LINE NO.	(2) YEAR	(3) MONTH	(4) LgComSales (OUTPUT)	(5) LgComSales (INPUT)	(6) NonMfgEmp (INPUT)	(7) ComPrice (INPUT)	(8) Ivan (INPUT)	(9) DennisKatrina (INPUT)	(10) Isaac (INPUT)	(11) HDHBD_01 (INPUT)	(12) HDHBD_02 (INPUT)	(13) HDHBD_03 (INPUT)	(14) HDHBD_12 (INPUT)
1	2014	JAN	493.203		305.340	8.310	0	0	0	134	0	0	0
2	2014	FEB	502.860		305.850	8.354	0	0	0	0	117	0	0
3	2014	MAR	497.543		306.410	8.399	0	0	0	0	0	60	0
4	2014	APR	515.466		307.050	8.444	0	0	0	0	0	0	0
5	2014	MAY	568.286		307.750	8.489	0	0	0	0	0	0	0
6	2014	JUN	649.307		308.510	8.533	0	0	0	0	0	0	0
7	2014	JUL	691.534		309.320	8.576	0	0	0	0	0	0	0
8	2014	AUG	697.949		310.210	8.619	0	0	0	0	0	0	0
9	2014	SEP	680.770		311.120	8.661	0	0	0	0	0	0	0
10	2014	OCT	618.866		312.050	8.705	0	0	0	0	0	0	0
11	2014	NOV	528.051		312.970	8.749	0	0	0	0	0	0	0
12	2014	DEC	490.647		313.860	8.795	0	0	0	0	0	0	76

VARIABLE	DESCRIPTION
LgComSales	Billing Cycle Large Commercial kWh per Customer per Billing Day
NonMfgEmp	Non-manufacturing Employment (000's)
ComPrice	12-Month Average of Real Commercial Price (cents per kWh)
Ivan	Binary Variable for Hurricane Ivan September 2004
DennisKatrina	Binary Variable for Hurricanes Dennis and Katrina July-September 2005
Isaac	Binary Variable for Hurricane Isaac August-September 2012
HDHBD_XX	Billing Cycle Large Commercial Heating Degree Hours per Billing Day for Month XX (01=January, etc.)

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of Data Shown:
___ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
_X_ Historical Years 1992 Through 1993
Witness: R. J. Alexander

FORECASTING MODEL: LARGE COMMERCIAL ENERGY

(1) LINE NO.	(2) YEAR	(3) MONTH	(4) Jan (INPUT)	(5) CDHBD_03 (INPUT)	(6) CDHBD_04 (INPUT)	(7) CDHBD_05 (INPUT)	(8) CDHBD_06 (INPUT)	(9) CDHBD_07 (INPUT)	(10) CDHBD_08 (INPUT)	(11) CDHBD_09 (INPUT)	(12) CDHBD_10 (INPUT)	(13) CDHBD_11 (INPUT)
1	1992	NOV	0	0	0	0	0	0	0	0	0	123
2	1992	DEC	0	0	0	0	0	0	0	0	0	0
3	1993	JAN	1	0	0	0	0	0	0	0	0	0
4	1993	FEB	0	0	0	0	0	0	0	0	0	0
5	1993	MAR	0	21	0	0	0	0	0	0	0	0
6	1993	APR	0	0	63	0	0	0	0	0	0	0
7	1993	MAY	0	0	0	152	0	0	0	0	0	0
8	1993	JUN	0	0	0	0	328	0	0	0	0	0
9	1993	JUL	0	0	0	0	0	439	0	0	0	0
10	1993	AUG	0	0	0	0	0	0	471	0	0	0
11	1993	SEP	0	0	0	0	0	0	0	433	0	0
12	1993	OCT	0	0	0	0	0	0	0	0	298	0
13	1993	NOV	0	0	0	0	0	0	0	0	0	130
14	1993	DEC	0	0	0	0	0	0	0	0	0	0

VARIABLE	DESCRIPTION
Jan	Monthly Binary Variable for January
CDHBD_XX	Billing Cycle Large Commercial Cooling Degree Hours per Billing Day for Month XX (03=March, etc.)

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of Data Shown:
___ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
_X_ Historical Years 1994 Through 1995
Witness: R. J. Alexander

FORECASTING MODEL: LARGE COMMERCIAL ENERGY

(1) LINE NO.	(2) YEAR	(3) MONTH	(4) Jan (INPUT)	(5) CDHBD_03 (INPUT)	(6) CDHBD_04 (INPUT)	(7) CDHBD_05 (INPUT)	(8) CDHBD_06 (INPUT)	(9) CDHBD_07 (INPUT)	(10) CDHBD_08 (INPUT)	(11) CDHBD_09 (INPUT)	(12) CDHBD_10 (INPUT)	(13) CDHBD_11 (INPUT)
1	1994	JAN	1	0	0	0	0	0	0	0	0	0
2	1994	FEB	0	0	0	0	0	0	0	0	0	0
3	1994	MAR	0	50	0	0	0	0	0	0	0	0
4	1994	APR	0	0	107	0	0	0	0	0	0	0
5	1994	MAY	0	0	0	231	0	0	0	0	0	0
6	1994	JUN	0	0	0	0	334	0	0	0	0	0
7	1994	JUL	0	0	0	0	0	399	0	0	0	0
8	1994	AUG	0	0	0	0	0	0	385	0	0	0
9	1994	SEP	0	0	0	0	0	0	0	381	0	0
10	1994	OCT	0	0	0	0	0	0	0	0	265	0
11	1994	NOV	0	0	0	0	0	0	0	0	0	135
12	1994	DEC	0	0	0	0	0	0	0	0	0	0
13	1995	JAN	1	0	0	0	0	0	0	0	0	0
14	1995	FEB	0	0	0	0	0	0	0	0	0	0
15	1995	MAR	0	41	0	0	0	0	0	0	0	0
16	1995	APR	0	0	101	0	0	0	0	0	0	0
17	1995	MAY	0	0	0	218	0	0	0	0	0	0
18	1995	JUN	0	0	0	0	375	0	0	0	0	0
19	1995	JUL	0	0	0	0	0	434	0	0	0	0
20	1995	AUG	0	0	0	0	0	0	460	0	0	0
21	1995	SEP	0	0	0	0	0	0	0	467	0	0
22	1995	OCT	0	0	0	0	0	0	0	0	319	0
23	1995	NOV	0	0	0	0	0	0	0	0	0	133
24	1995	DEC	0	0	0	0	0	0	0	0	0	0

VARIABLE	DESCRIPTION
Jan	Monthly Binary Variable for January
CDHBD_XX	Billing Cycle Large Commercial Cooling Degree Hours per Billing Day for Month XX (03=March, etc.)

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of Data Shown:
___ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
_X_ Historical Years 1996 Through 1997
Witness: R. J. Alexander

FORECASTING MODEL: LARGE COMMERCIAL ENERGY

(1) LINE NO.	(2) YEAR	(3) MONTH	(4) Jan (INPUT)	(5) CDHBD_03 (INPUT)	(6) CDHBD_04 (INPUT)	(7) CDHBD_05 (INPUT)	(8) CDHBD_06 (INPUT)	(9) CDHBD_07 (INPUT)	(10) CDHBD_08 (INPUT)	(11) CDHBD_09 (INPUT)	(12) CDHBD_10 (INPUT)	(13) CDHBD_11 (INPUT)
1	1996	JAN	1	0	0	0	0	0	0	0	0	0
2	1996	FEB	0	0	0	0	0	0	0	0	0	0
3	1996	MAR	0	50	0	0	0	0	0	0	0	0
4	1996	APR	0	0	53	0	0	0	0	0	0	0
5	1996	MAY	0	0	0	209	0	0	0	0	0	0
6	1996	JUN	0	0	0	0	393	0	0	0	0	0
7	1996	JUL	0	0	0	0	0	475	0	0	0	0
8	1996	AUG	0	0	0	0	0	0	463	0	0	0
9	1996	SEP	0	0	0	0	0	0	0	412	0	0
10	1996	OCT	0	0	0	0	0	0	0	0	268	0
11	1996	NOV	0	0	0	0	0	0	0	0	0	150
12	1996	DEC	0	0	0	0	0	0	0	0	0	0
13	1997	JAN	1	0	0	0	0	0	0	0	0	0
14	1997	FEB	0	0	0	0	0	0	0	0	0	0
15	1997	MAR	0	92	0	0	0	0	0	0	0	0
16	1997	APR	0	0	122	0	0	0	0	0	0	0
17	1997	MAY	0	0	0	168	0	0	0	0	0	0
18	1997	JUN	0	0	0	0	312	0	0	0	0	0
19	1997	JUL	0	0	0	0	0	435	0	0	0	0
20	1997	AUG	0	0	0	0	0	0	435	0	0	0
21	1997	SEP	0	0	0	0	0	0	0	431	0	0
22	1997	OCT	0	0	0	0	0	0	0	0	316	0
23	1997	NOV	0	0	0	0	0	0	0	0	0	83
24	1997	DEC	0	0	0	0	0	0	0	0	0	0

VARIABLE	DESCRIPTION
Jan	Monthly Binary Variable for January
CDHBD_XX	Billing Cycle Large Commercial Cooling Degree Hours per Billing Day for Month XX (03=March, etc.)

Supporting Schedules: Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of Data Shown:
___ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
_X_ Historical Years 1998 Through 1999
Witness: R. J. Alexander

FORECASTING MODEL: LARGE COMMERCIAL ENERGY

(1) LINE NO.	(2) YEAR	(3) MONTH	(4) Jan (INPUT)	(5) CDHBD_03 (INPUT)	(6) CDHBD_04 (INPUT)	(7) CDHBD_05 (INPUT)	(8) CDHBD_06 (INPUT)	(9) CDHBD_07 (INPUT)	(10) CDHBD_08 (INPUT)	(11) CDHBD_09 (INPUT)	(12) CDHBD_10 (INPUT)	(13) CDHBD_11 (INPUT)
1	1998	JAN	1	0	0	0	0	0	0	0	0	0
2	1998	FEB	0	0	0	0	0	0	0	0	0	0
3	1998	MAR	0	22	0	0	0	0	0	0	0	0
4	1998	APR	0	0	93	0	0	0	0	0	0	0
5	1998	MAY	0	0	0	224	0	0	0	0	0	0
6	1998	JUN	0	0	0	0	436	0	0	0	0	0
7	1998	JUL	0	0	0	0	0	499	0	0	0	0
8	1998	AUG	0	0	0	0	0	0	451	0	0	0
9	1998	SEP	0	0	0	0	0	0	0	422	0	0
10	1998	OCT	0	0	0	0	0	0	0	0	319	0
11	1998	NOV	0	0	0	0	0	0	0	0	0	153
12	1998	DEC	0	0	0	0	0	0	0	0	0	0
13	1999	JAN	1	0	0	0	0	0	0	0	0	0
14	1999	FEB	0	0	0	0	0	0	0	0	0	0
15	1999	MAR	0	35	0	0	0	0	0	0	0	0
16	1999	APR	0	0	118	0	0	0	0	0	0	0
17	1999	MAY	0	0	0	221	0	0	0	0	0	0
18	1999	JUN	0	0	0	0	333	0	0	0	0	0
19	1999	JUL	0	0	0	0	0	419	0	0	0	0
20	1999	AUG	0	0	0	0	0	0	474	0	0	0
21	1999	SEP	0	0	0	0	0	0	0	425	0	0
22	1999	OCT	0	0	0	0	0	0	0	0	267	0
23	1999	NOV	0	0	0	0	0	0	0	0	0	114
24	1999	DEC	0	0	0	0	0	0	0	0	0	0

VARIABLE	DESCRIPTION
Jan	Monthly Binary Variable for January
CDHBD_XX	Billing Cycle Large Commercial Cooling Degree Hours per Billing Day for Month XX (03=March, etc.)

Supporting Schedules: Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of Data Shown:
___ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
_X_ Historical Years 2000 Through 2001
Witness: R. J. Alexander

FORECASTING MODEL: LARGE COMMERCIAL ENERGY

(1) LINE NO.	(2) YEAR	(3) MONTH	(4) Jan (INPUT)	(5) CDHBD_03 (INPUT)	(6) CDHBD_04 (INPUT)	(7) CDHBD_05 (INPUT)	(8) CDHBD_06 (INPUT)	(9) CDHBD_07 (INPUT)	(10) CDHBD_08 (INPUT)	(11) CDHBD_09 (INPUT)	(12) CDHBD_10 (INPUT)	(13) CDHBD_11 (INPUT)
1	2000	JAN	1	0	0	0	0	0	0	0	0	0
2	2000	FEB	0	0	0	0	0	0	0	0	0	0
3	2000	MAR	0	69	0	0	0	0	0	0	0	0
4	2000	APR	0	0	102	0	0	0	0	0	0	0
5	2000	MAY	0	0	0	205	0	0	0	0	0	0
6	2000	JUN	0	0	0	0	388	0	0	0	0	0
7	2000	JUL	0	0	0	0	0	480	0	0	0	0
8	2000	AUG	0	0	0	0	0	0	478	0	0	0
9	2000	SEP	0	0	0	0	0	0	0	424	0	0
10	2000	OCT	0	0	0	0	0	0	0	0	238	0
11	2000	NOV	0	0	0	0	0	0	0	0	0	150
12	2000	DEC	0	0	0	0	0	0	0	0	0	0
13	2001	JAN	1	0	0	0	0	0	0	0	0	0
14	2001	FEB	0	0	0	0	0	0	0	0	0	0
15	2001	MAR	0	50	0	0	0	0	0	0	0	0
16	2001	APR	0	0	99	0	0	0	0	0	0	0
17	2001	MAY	0	0	0	196	0	0	0	0	0	0
18	2001	JUN	0	0	0	0	355	0	0	0	0	0
19	2001	JUL	0	0	0	0	0	407	0	0	0	0
20	2001	AUG	0	0	0	0	0	0	422	0	0	0
21	2001	SEP	0	0	0	0	0	0	0	384	0	0
22	2001	OCT	0	0	0	0	0	0	0	0	219	0
23	2001	NOV	0	0	0	0	0	0	0	0	0	120
24	2001	DEC	0	0	0	0	0	0	0	0	0	0

VARIABLE	DESCRIPTION
Jan	Monthly Binary Variable for January
CDHBD_XX	Billing Cycle Large Commercial Cooling Degree Hours per Billing Day for Month XX (03=March, etc.)

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of Data Shown:
___ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
_X_ Historical Years 2002 Through 2003
Witness: R. J. Alexander

FORECASTING MODEL: LARGE COMMERCIAL ENERGY

(1) LINE NO.	(2) YEAR	(3) MONTH	(4) Jan (INPUT)	(5) CDHBD_03 (INPUT)	(6) CDHBD_04 (INPUT)	(7) CDHBD_05 (INPUT)	(8) CDHBD_06 (INPUT)	(9) CDHBD_07 (INPUT)	(10) CDHBD_08 (INPUT)	(11) CDHBD_09 (INPUT)	(12) CDHBD_10 (INPUT)	(13) CDHBD_11 (INPUT)
1	2002	JAN	1	0	0	0	0	0	0	0	0	0
2	2002	FEB	0	0	0	0	0	0	0	0	0	0
3	2002	MAR	0	32	0	0	0	0	0	0	0	0
4	2002	APR	0	0	114	0	0	0	0	0	0	0
5	2002	MAY	0	0	0	282	0	0	0	0	0	0
6	2002	JUN	0	0	0	0	336	0	0	0	0	0
7	2002	JUL	0	0	0	0	0	409	0	0	0	0
8	2002	AUG	0	0	0	0	0	0	429	0	0	0
9	2002	SEP	0	0	0	0	0	0	0	415	0	0
10	2002	OCT	0	0	0	0	0	0	0	0	329	0
11	2002	NOV	0	0	0	0	0	0	0	0	0	128
12	2002	DEC	0	0	0	0	0	0	0	0	0	0
13	2003	JAN	1	0	0	0	0	0	0	0	0	0
14	2003	FEB	0	0	0	0	0	0	0	0	0	0
15	2003	MAR	0	43	0	0	0	0	0	0	0	0
16	2003	APR	0	0	110	0	0	0	0	0	0	0
17	2003	MAY	0	0	0	258	0	0	0	0	0	0
18	2003	JUN	0	0	0	0	356	0	0	0	0	0
19	2003	JUL	0	0	0	0	0	386	0	0	0	0
20	2003	AUG	0	0	0	0	0	0	397	0	0	0
21	2003	SEP	0	0	0	0	0	0	0	392	0	0
22	2003	OCT	0	0	0	0	0	0	0	0	235	0
23	2003	NOV	0	0	0	0	0	0	0	0	0	153
24	2003	DEC	0	0	0	0	0	0	0	0	0	0

VARIABLE	DESCRIPTION
Jan	Monthly Binary Variable for January
CDHBD_XX	Billing Cycle Large Commercial Cooling Degree Hours per Billing Day for Month XX (03=March, etc.)

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of Data Shown:
___ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
_X_ Historical Years 2004 Through 2005
Witness: R. J. Alexander

FORECASTING MODEL: LARGE COMMERCIAL ENERGY

(1) LINE NO.	(2) YEAR	(3) MONTH	(4) Jan (INPUT)	(5) CDHBD_03 (INPUT)	(6) CDHBD_04 (INPUT)	(7) CDHBD_05 (INPUT)	(8) CDHBD_06 (INPUT)	(9) CDHBD_07 (INPUT)	(10) CDHBD_08 (INPUT)	(11) CDHBD_09 (INPUT)	(12) CDHBD_10 (INPUT)	(13) CDHBD_11 (INPUT)
1	2004	JAN	1	0	0	0	0	0	0	0	0	0
2	2004	FEB	0	0	0	0	0	0	0	0	0	0
3	2004	MAR	0	39	0	0	0	0	0	0	0	0
4	2004	APR	0	0	88	0	0	0	0	0	0	0
5	2004	MAY	0	0	0	192	0	0	0	0	0	0
6	2004	JUN	0	0	0	0	364	0	0	0	0	0
7	2004	JUL	0	0	0	0	0	421	0	0	0	0
8	2004	AUG	0	0	0	0	0	0	424	0	0	0
9	2004	SEP	0	0	0	0	0	0	0	385	0	0
10	2004	OCT	0	0	0	0	0	0	0	0	321	0
11	2004	NOV	0	0	0	0	0	0	0	0	0	195
12	2004	DEC	0	0	0	0	0	0	0	0	0	0
13	2005	JAN	1	0	0	0	0	0	0	0	0	0
14	2005	FEB	0	0	0	0	0	0	0	0	0	0
15	2005	MAR	0	29	0	0	0	0	0	0	0	0
16	2005	APR	0	0	72	0	0	0	0	0	0	0
17	2005	MAY	0	0	0	156	0	0	0	0	0	0
18	2005	JUN	0	0	0	0	351	0	0	0	0	0
19	2005	JUL	0	0	0	0	0	436	0	0	0	0
20	2005	AUG	0	0	0	0	0	0	437	0	0	0
21	2005	SEP	0	0	0	0	0	0	0	449	0	0
22	2005	OCT	0	0	0	0	0	0	0	0	357	0
23	2005	NOV	0	0	0	0	0	0	0	0	0	129
24	2005	DEC	0	0	0	0	0	0	0	0	0	0

VARIABLE	DESCRIPTION
Jan	Monthly Binary Variable for January
CDHBD_XX	Billing Cycle Large Commercial Cooling Degree Hours per Billing Day for Month XX (03=March, etc.)

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of Data Shown:
___ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
_X_ Historical Years 2006 Through 2007
Witness: R. J. Alexander

FORECASTING MODEL: LARGE COMMERCIAL ENERGY

(1) LINE NO.	(2) YEAR	(3) MONTH	(4) Jan (INPUT)	(5) CDHBD_03 (INPUT)	(6) CDHBD_04 (INPUT)	(7) CDHBD_05 (INPUT)	(8) CDHBD_06 (INPUT)	(9) CDHBD_07 (INPUT)	(10) CDHBD_08 (INPUT)	(11) CDHBD_09 (INPUT)	(12) CDHBD_10 (INPUT)	(13) CDHBD_11 (INPUT)
1	2006	JAN	1	0	0	0	0	0	0	0	0	0
2	2006	FEB	0	0	0	0	0	0	0	0	0	0
3	2006	MAR	0	65	0	0	0	0	0	0	0	0
4	2006	APR	0	0	145	0	0	0	0	0	0	0
5	2006	MAY	0	0	0	250	0	0	0	0	0	0
6	2006	JUN	0	0	0	0	394	0	0	0	0	0
7	2006	JUL	0	0	0	0	0	481	0	0	0	0
8	2006	AUG	0	0	0	0	0	0	451	0	0	0
9	2006	SEP	0	0	0	0	0	0	0	415	0	0
10	2006	OCT	0	0	0	0	0	0	0	0	282	0
11	2006	NOV	0	0	0	0	0	0	0	0	0	96
12	2006	DEC	0	0	0	0	0	0	0	0	0	0
13	2007	JAN	1	0	0	0	0	0	0	0	0	0
14	2007	FEB	0	0	0	0	0	0	0	0	0	0
15	2007	MAR	0	47	0	0	0	0	0	0	0	0
16	2007	APR	0	0	113	0	0	0	0	0	0	0
17	2007	MAY	0	0	0	222	0	0	0	0	0	0
18	2007	JUN	0	0	0	0	341	0	0	0	0	0
19	2007	JUL	0	0	0	0	0	440	0	0	0	0
20	2007	AUG	0	0	0	0	0	0	476	0	0	0
21	2007	SEP	0	0	0	0	0	0	0	449	0	0
22	2007	OCT	0	0	0	0	0	0	0	0	332	0
23	2007	NOV	0	0	0	0	0	0	0	0	0	116
24	2007	DEC	0	0	0	0	0	0	0	0	0	0

VARIABLE	DESCRIPTION
Jan	Monthly Binary Variable for January
CDHBD_XX	Billing Cycle Large Commercial Cooling Degree Hours per Billing Day for Month XX (03=March, etc.)

Supporting Schedules: Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of Data Shown:
___ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
_X_ Historical Years 2008 Through 2009
Witness: R. J. Alexander

FORECASTING MODEL: LARGE COMMERCIAL ENERGY

(1) LINE NO.	(2) YEAR	(3) MONTH	(4) Jan (INPUT)	(5) CDHBD_03 (INPUT)	(6) CDHBD_04 (INPUT)	(7) CDHBD_05 (INPUT)	(8) CDHBD_06 (INPUT)	(9) CDHBD_07 (INPUT)	(10) CDHBD_08 (INPUT)	(11) CDHBD_09 (INPUT)	(12) CDHBD_10 (INPUT)	(13) CDHBD_11 (INPUT)
1	2008	JAN	1	0	0	0	0	0	0	0	0	0
2	2008	FEB	0	0	0	0	0	0	0	0	0	0
3	2008	MAR	0	35	0	0	0	0	0	0	0	0
4	2008	APR	0	0	94	0	0	0	0	0	0	0
5	2008	MAY	0	0	0	210	0	0	0	0	0	0
6	2008	JUN	0	0	0	0	412	0	0	0	0	0
7	2008	JUL	0	0	0	0	0	464	0	0	0	0
8	2008	AUG	0	0	0	0	0	0	483	0	0	0
9	2008	SEP	0	0	0	0	0	0	0	434	0	0
10	2008	OCT	0	0	0	0	0	0	0	0	264	0
11	2008	NOV	0	0	0	0	0	0	0	0	0	86
12	2008	DEC	0	0	0	0	0	0	0	0	0	0
13	2009	JAN	1	0	0	0	0	0	0	0	0	0
14	2009	FEB	0	0	0	0	0	0	0	0	0	0
15	2009	MAR	0	49	0	0	0	0	0	0	0	0
16	2009	APR	0	0	93	0	0	0	0	0	0	0
17	2009	MAY	0	0	0	222	0	0	0	0	0	0
18	2009	JUN	0	0	0	0	366	0	0	0	0	0
19	2009	JUL	0	0	0	0	0	478	0	0	0	0
20	2009	AUG	0	0	0	0	0	0	421	0	0	0
21	2009	SEP	0	0	0	0	0	0	0	366	0	0
22	2009	OCT	0	0	0	0	0	0	0	0	321	0
23	2009	NOV	0	0	0	0	0	0	0	0	0	115
24	2009	DEC	0	0	0	0	0	0	0	0	0	0

VARIABLE	DESCRIPTION
Jan	Monthly Binary Variable for January
CDHBD_XX	Billing Cycle Large Commercial Cooling Degree Hours per Billing Day for Month XX (03=March, etc.)

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of Data Shown:
___ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
_X_ Historical Years 2010 Through 2011
Witness: R. J. Alexander

FORECASTING MODEL: LARGE COMMERCIAL ENERGY

(1) LINE NO.	(2) YEAR	(3) MONTH	(4) Jan (INPUT)	(5) CDHBD_03 (INPUT)	(6) CDHBD_04 (INPUT)	(7) CDHBD_05 (INPUT)	(8) CDHBD_06 (INPUT)	(9) CDHBD_07 (INPUT)	(10) CDHBD_08 (INPUT)	(11) CDHBD_09 (INPUT)	(12) CDHBD_10 (INPUT)	(13) CDHBD_11 (INPUT)
1	2010	JAN	1	0	0	0	0	0	0	0	0	0
2	2010	FEB	0	0	0	0	0	0	0	0	0	0
3	2010	MAR	0	6	0	0	0	0	0	0	0	0
4	2010	APR	0	0	67	0	0	0	0	0	0	0
5	2010	MAY	0	0	0	211	0	0	0	0	0	0
6	2010	JUN	0	0	0	0	390	0	0	0	0	0
7	2010	JUL	0	0	0	0	0	465	0	0	0	0
8	2010	AUG	0	0	0	0	0	0	509	0	0	0
9	2010	SEP	0	0	0	0	0	0	0	436	0	0
10	2010	OCT	0	0	0	0	0	0	0	0	293	0
11	2010	NOV	0	0	0	0	0	0	0	0	0	149
12	2010	DEC	0	0	0	0	0	0	0	0	0	0
13	2011	JAN	1	0	0	0	0	0	0	0	0	0
14	2011	FEB	0	0	0	0	0	0	0	0	0	0
15	2011	MAR	0	62	0	0	0	0	0	0	0	0
16	2011	APR	0	0	154	0	0	0	0	0	0	0
17	2011	MAY	0	0	0	236	0	0	0	0	0	0
18	2011	JUN	0	0	0	0	403	0	0	0	0	0
19	2011	JUL	0	0	0	0	0	486	0	0	0	0
20	2011	AUG	0	0	0	0	0	0	484	0	0	0
21	2011	SEP	0	0	0	0	0	0	0	421	0	0
22	2011	OCT	0	0	0	0	0	0	0	0	239	0
23	2011	NOV	0	0	0	0	0	0	0	0	0	95
24	2011	DEC	0	0	0	0	0	0	0	0	0	0

VARIABLE	DESCRIPTION
Jan	Monthly Binary Variable for January
CDHBD_XX	Billing Cycle Large Commercial Cooling Degree Hours per Billing Day for Month XX (03=March, etc.)

Supporting Schedules: Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of Data Shown:
___ Projected Test Year Ended 12/31/14
_X_ Prior Year Ended 12/31/13
_X_ Historical Year 2012
Witness: R. J. Alexander

FORECASTING MODEL: LARGE COMMERCIAL ENERGY

(1) LINE NO.	(2) YEAR	(3) MONTH	(4) Jan (INPUT)	(5) CDHBD_03 (INPUT)	(6) CDHBD_04 (INPUT)	(7) CDHBD_05 (INPUT)	(8) CDHBD_06 (INPUT)	(9) CDHBD_07 (INPUT)	(10) CDHBD_08 (INPUT)	(11) CDHBD_09 (INPUT)	(12) CDHBD_10 (INPUT)	(13) CDHBD_11 (INPUT)
1	2012	JAN	1	0	0	0	0	0	0	0	0	0
2	2012	FEB	0	0	0	0	0	0	0	0	0	0
3	2012	MAR	0	81	0	0	0	0	0	0	0	0
4	2012	APR	0	0	179	0	0	0	0	0	0	0
5	2012	MAY	0	0	0	249	0	0	0	0	0	0
6	2012	JUN	0	0	0	0	393	0	0	0	0	0
7	2012	JUL	0	0	0	0	0	438	0	0	0	0
8	2012	AUG	0	0	0	0	0	0	449	0	0	0
9	2012	SEP	0	0	0	0	0	0	0	409	0	0
10	2012	OCT	0	0	0	0	0	0	0	0	277	0
11	2012	NOV	0	0	0	0	0	0	0	0	0	128
12	2012	DEC	0	0	0	0	0	0	0	0	0	0
13	2013	JAN	1	0	0	0	0	0	0	0	0	0
14	2013	FEB	0	0	0	0	0	0	0	0	0	0
15	2013	MAR	0	46	0	0	0	0	0	0	0	0
16	2013	APR	0	0	104	0	0	0	0	0	0	0
17	2013	MAY	0	0	0	216	0	0	0	0	0	0
18	2013	JUN	0	0	0	0	364	0	0	0	0	0
19	2013	JUL	0	0	0	0	0	446	0	0	0	0
20	2013	AUG	0	0	0	0	0	0	449	0	0	0
21	2013	SEP	0	0	0	0	0	0	0	416	0	0
22	2013	OCT	0	0	0	0	0	0	0	0	286	0
23	2013	NOV	0	0	0	0	0	0	0	0	0	128
24	2013	DEC	0	0	0	0	0	0	0	0	0	0

VARIABLE	DESCRIPTION
Jan	Monthly Binary Variable for January
CDHBD_XX	Billing Cycle Large Commercial Cooling Degree Hours per Billing Day for Month XX (03=March, etc.)

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of Data Shown:
X Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
___ Historical Year 2012
Witness: R. J. Alexander

FORECASTING MODEL: LARGE COMMERCIAL ENERGY

(1) LINE NO.	(2) YEAR	(3) MONTH	(4) Jan (INPUT)	(5) CDHBD_03 (INPUT)	(6) CDHBD_04 (INPUT)	(7) CDHBD_05 (INPUT)	(8) CDHBD_06 (INPUT)	(9) CDHBD_07 (INPUT)	(10) CDHBD_08 (INPUT)	(11) CDHBD_09 (INPUT)	(12) CDHBD_10 (INPUT)	(13) CDHBD_11 (INPUT)
1	2014	JAN	1	0	0	0	0	0	0	0	0	0
2	2014	FEB	0	0	0	0	0	0	0	0	0	0
3	2014	MAR	0	46	0	0	0	0	0	0	0	0
4	2014	APR	0	0	104	0	0	0	0	0	0	0
5	2014	MAY	0	0	0	216	0	0	0	0	0	0
6	2014	JUN	0	0	0	0	364	0	0	0	0	0
7	2014	JUL	0	0	0	0	0	446	0	0	0	0
8	2014	AUG	0	0	0	0	0	0	449	0	0	0
9	2014	SEP	0	0	0	0	0	0	0	416	0	0
10	2014	OCT	0	0	0	0	0	0	0	0	286	0
11	2014	NOV	0	0	0	0	0	0	0	0	0	128
12	2014	DEC	0	0	0	0	0	0	0	0	0	0

100

VARIABLE	DESCRIPTION
Jan	Monthly Binary Variable for January
CDHBD_XX	Billing Cycle Large Commercial Cooling Degree Hours per Billing Day for Month XX (03=March, etc.)

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: For a projected test year, provide a schedule of assumptions used in developing projected or estimated data. As a minimum, state assumptions used for balance sheet, income statement and sales forecast.

Type of Data Shown:
_X_Projected Test Year Ended 12/31/14
___Prior Year Ended 12/31/13
___Historical Year Ended 12/31/12
Witness: See Below

Index to Assumptions

(1) Line No.	(2) Item	(3) Forecast/Budget	(4) Witness	(5) Page
1				
2	I.	General Assumptions		
3		A. Forecast of Customer, Energy, Peak Demand, and Revenue	Alexander	3
4				
5		B. Operations and Maintenance Budget Excluding Fuel and	Alexander	4
6		Purchased Power	Ritenour	5
7			Grove	
8			Caldwell	
9			McQuagge	
10			Neyman	
11			Strickland	
12			Erickson	
13		C. Financial Assumptions	Ritenour	6
14			Teel	
15	II.	Operating Assumptions	Ritenour	7
16		A. Income Statement	Alexander	
17			Burroughs	
18			Grove	
19			Caldwell	
20			McQuagge	
21			Neyman	
22			Strickland	
23			Erickson	
24		B. Average Annual Heat Rates for January 2014 - December 2014	Grove	10
25		C. Outage Rates for January 2014 - December 2014	Grove	11
26		D. Planned Maintenance for January 2014 - December 2014	Grove	12
27		E. Net Unit Capacity Ratings for January 2014 - December 2014	Grove	13

28 Totals may not add due to rounding.

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: For a projected test year, provide a schedule of assumptions used in developing projected or estimated data. As a minimum, state assumptions used for balance sheet, income statement and sales forecast.

Type of Data Shown:
_X_ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
___ Historical Year Ended 12/31/12
Witness: See Below

Index to Assumptions

(1) Line No.	(2) Item	(3) Forecast/Budget	(4) Witness	(5) Page
1				
2		F. Other Fuel Budget Assumptions for January 2014 - December 2014	Burroughs	14
3			Grove	
4			Alexander	
5	III.	Capital Additions Assumptions		
6		A. Construction Expenditures	Ritenour	16
7			Grove	
8			Caldwell	
9			McQuagge	
10		B. Electric Plant-in-Service and Accumulated Depreciation	Ritenour	17
11			Grove	
12			Caldwell	
13			McQuagge	
14			Erickson	
15	IV.	Balance Sheet Assumptions		
16		A. 13 Month Average Assets	Ritenour	18
17			Burroughs	
18			Erickson	
19		B. 13 Month Average Capitalization and Liabilities	Ritenour	22
20			Erickson	

21 Totals may not add due to rounding.

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: For a projected test year, provide a schedule of assumptions used in developing projected or estimated data. As a minimum, state assumptions used for balance sheet, income statement and sales forecast.

Type of Data Shown:
_X_ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
___ Historical Year Ended 12/31/12
Witness: R. J. Alexander

I. GENERAL ASSUMPTIONS

A. FORECAST OF CUSTOMER , ENERGY, PEAK DEMAND, AND REVENUE

(1)
Line
No.

Normal weather conditions were assumed in the development of energy sales and peak demand forecasts. Monthly normal weather is the average, over the past 20 years of cooling and heating degree hours based on temperatures measured at the National Oceanic and Atmospheric Administration (NOAA) weather station located in Pensacola, Florida.

Gulf projects that the economy in our service area will begin recovery in 2013 and continue until economic indicators either return to or exceed 2006 pre-recession levels by the end of 2015.

Economic projections were provided by Moody's Analytics, a well respected economic forecasting firm.

Gulf utilized its most recent DSM plan, which was approved by the Commission in Order No. PSC-11-0114-PAA-EG on February 11, 2011, to adjust forecasted sales and annual system peak demands for projected conservation impacts.

Base rate revenues were calculated using the FPSC approved rate schedules in effect at the time of the forecast.

YEAR ENDED DECEMBER, 2014 TEST YEAR GROWTH RATES

CUSTOMERS	1.3%
RETAIL KWH SALES	0.6%

Totals may not add due to rounding.

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: For a projected test year, provide a schedule of assumptions used in developing projected or estimated data. As a minimum, state assumptions used for balance sheet, income statement and sales forecast.

Type of Data Shown:
_X_ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
___ Historical Year Ended 12/31/12
Witness: See Below

I. GENERAL ASSUMPTIONS

B. TEST YEAR OPERATIONS AND MAINTENANCE BUDGET EXCLUDING FUEL AND PURCHASED POWER

(1) Line No.	(2) Item	(3) Amount	(4) Witness	(5) Assumption
1	1. Inflation Factor -		Ritenour	Bureau of Labor Statistics: Consumer Price Index (Urban Consumer); Moody's Analytics.
2	2013	2.7%		
3	2014	2.5%		
4	2. Retail Customers -			
5	Dec-2014	445,187	Alexander	Based on assumptions outlined in Section I.A. of this schedule and as described in direct testimony.
6	Growth rate	1.3%		
7	3. Retail Energy - MWH	11,154,278	Alexander	Derived using assumptions outlined in Section I.A. of this schedule and as described in direct testimony.
8	Growth rate	0.6%		
9				
10	4. Peak Demand - MW	2,522	Alexander	Projected using assumptions outlined in Section I.A. of this schedule and described in direct testimony
11	Growth rate	0.3%		
12	5. Forecasted Composite		Ritenour	Assumptions were based on inflation and current salary trends of other companies and utilities.
13	Wage and Salary			
14	Increase Guidelines			
15	- Exempt	3.00%		
16	- Non-exempt	3.00%		
17	- Covered	2.50%		

18 Totals may not add due to rounding.

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: For a projected test year, provide a schedule of assumptions used in developing projected or estimated data. As a minimum, state assumptions used for balance sheet, income statement and sales forecast.

Type of Data Shown:
_X_ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
___ Historical Year Ended 12/31/12
Witness: See Below

I. GENERAL ASSUMPTIONS

B. TEST YEAR OPERATIONS AND MAINTENANCE BUDGET EXCLUDING FUEL AND PURCHASED POWER

(1) Line No.	(2) Item	(3) Amount (000's)	(4) Witness	(5) Assumption
1	6. January - December 2014			
2	Operations Expense (net of fuel and purchased power):		Ritenour	
3	Production	$ 69,921	Grove	Based on Planning Units' budgets which incorporate the above
4	Transmission	$ 19,911	Caldwell	assumptions and were developed using the process described in
5	Distribution	$ 20,461	McQuagge	MFR F-5 and direct testimony of each witness.
6	Customer Accounting	$ 25,850	Neyman	
7	Customer Service and Information	$ 38,602	Strickland	
8	Sales Expense	$ 1,391	Strickland	
9	Administrative and General	$ 88,309	Erickson	
10	Total Operations	$ 264,445		
11	7. January - December 2014			
12	Maintenance Expense:		Ritenour	
13	Production	$ 73,229	Grove	Based on Planning Units' budgets which incorporate the above
14	Transmission	$ 7,475	Caldwell	assumptions and were developed using the process described in
15	Distribution	$ 25,277	McQuagge	MFR F-5 and direct testimony of each witness.
16	Administrative and General	$ 687	Erickson	
17	Total Maintenance	$ 106,668		

18 Totals may not add due to rounding.

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: For a projected test year, provide a schedule of assumptions used in developing projected or estimated data. As a minimum, state assumptions used for balance sheet, income statement and sales forecast.

Type of Data Shown:
_X_Projected Test Year Ended 12/31/14
___Prior Year Ended 12/31/13
___Historical Year Ended 12/31/12
Witness: See Below

I. GENERAL ASSUMPTIONS
C. TEST YEAR FINANCIAL ASSUMPTIONS

(1) Line No.	(2) Item	(3) Amount	(4) Witness	(5) Assumption
1	1. Interest Rates on Commercial Paper		Ritenour	Interest rate assumptions are provided by SCS Financial Planning based upon a market forecast by Moody's Analytics. The monthly amount of short term debt is reflected on Exhibit SDR-1, Schedule 7, page 2 of 3.
2	1st Quarter, 2014	0.60%		
3	2nd Quarter, 2014	0.65%		
4	3rd Quarter, 2014	0.90%		
5	4th Quarter, 2014	1.35%		
6	2. Interest Rates on Long-Term Debt; Issuances		Ritenour	The new issues of long-term debt are based on Gulf's need for additional external funds while maintaining the Company's target long-term debt ratio of 50%. $70 million is projected to be issued in April 2014, and $140 million in October 2014. There is one projected retirement for October 2014.
7	and Retirements of Long-Term Debt			
8	April 2014 ($70M Issuance)	5.85%		
9	October 2014 ($140M Issuance)	6.25%		
10	October 2014 ($75M Retirement)	4.90%		
11	3. Dividends to Southern Company	$ 120,560	Ritenour Teel	Based on projections of Southern Company's cash dividends to its shareholders and its net operating expenses. Southern's total cash requirement is then apportioned to the operating companies such that dividends paid to Southern are proportionate to Southern's common equity investment in the operating company.
12				
13				
14				
15	4. Dividends on Preference Stock	$ 8,880	Ritenour	The projected amount is calculated by multiplying each preference principal by its dividend rate and dividing by 12. The calculation is adjusted for any new issues and scheduled retirements.
16				
17				
18	5. Capital Contributions from	$ 120,798	Ritenour Teel	Based on Southern Company's ability to market new issues of its common stock and the operating company's need for external funds while maintaining the company's 45% common equity ratio.
19	Southern Company			
20				
21	6. Retirement of First Mortgage Bond	$ 0	Ritenour	There are none projected in the test year.
22	7. Retirement of Pollution Control Bond	$ 0	Ritenour	There are none projected in the test year.
23	8. Preference Stock Issues	$ 0	Ritenour	Based on Gulf's projected needs of cash and the company's target preference stock ratio of 5%. There are no preference stock issues forecasted in the test year.
24				
25	9. Pollution Control Bond Issue	$ 0	Ritenour	There are no Pollution Control Bond issues forecasted in the test year.
26	Totals may not add due to rounding.			

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FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: For a projected test year, provide a schedule of assumptions used in developing projected or estimated data. As a minimum, state assumptions used for balance sheet, income statement and sales forecast.

Type of Data Shown:
_X_ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
___ Historical Year Ended 12/31/12
Witness: See Below

II. OPERATING ASSUMPTIONS
A. INCOME STATEMENT

(1) Line No.		(2) Item	(3) Amount (000's)	(4) Witness	(5) Assumption
1	1.	Total Electric Revenue	$ 1,572,445	Ritenour Alexander	Base rate revenues (billed and unbilled) are input to the Financial Model. The monthly fuel clause revenues (billed and unbilled) are based on forecasted monthly recoverable fuel expense, interchange costs and MWH sales. Energy Conservation Cost Recovery clause revenues (billed and unbilled) are calculated based on forecasted monthly recoverable expenses and MWH sales. Purchased Power Capacity Clause revenues (billed and unbilled) are calculated based on monthly net pool capacity and non-associated purchase power agreements. Environmental Cost Recovery Clause revenues (billed and unbilled) are calculated based on qualified monthly environmental costs. Sales for Resale are derived from the Energy Budget described in MFR F-5. With the exception of Municipal Franchise Fees and County Franchise Fees, Other Operating Revenues are input based on an analysis of the accounts. Municipal Franchise Fees and County Franchise Fees are calculated using an input factor based on historical data.
11	2.	Fuel & Emission Allowance Expense (without Fuel Handling)	$ 614,449	Ritenour Burroughs	The projected amount is derived from the Fuel Budget as described in MFR F-5. This expense is entered into the Financial Model by direct interface with the FUELPRO model.
13	3.	Purchased Power	$ 88,019	Ritenour Grove	The projected amount is derived from the Interchange Budget as described in MFR F-5. This expense is entered into the Financial Model by direct interface with the PROSYM model.
15	4.	Operations Expense (including Fuel Handling)	$ 264,445	Ritenour Grove Caldwell McQuagge Neyman Erickson Strickland	The projected amount is derived from the O&M Budget as described in Section I.B. of this schedule. These expenses are summarized and input into the Financial Model.
22	5.	Maintenance Expense	$ 106,667	Ritenour Grove Caldwell McQuagge Erickson	The projected amount is derived from the O&M Budget as described in Section I.B. of this schedule. These expenses are summarized and input into the Financial Model.
27	6.	Depreciation Expense	$ 149,469	Ritenour Erickson	The projected amount is calculated by Corporate Planning utilizing the Plant in Service inputs as described in Section III.A. of this MFR. This amount is the electric depreciation only; it excludes depreciation associated with transportation.
30	7.	Amortization Expense	$ 6,884	Ritenour Erickson	The projected amount is input into the Financial Model based on projected Plant balances as described in Section III.A. of this MFR. It is electric only.
32	8.	Amortization Expense Investment Tax Credit	$ (1,224)	Ritenour Erickson	The projected amount is the amortization of the Investment Tax Credits which are amortized over the life of related assets, pursuant to IRS regulations.
34	Totals may not add due to rounding.				

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Supporting Schedules: B-3, B-7, B-9

Recap Schedules: B-1, C-1

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: For a projected test year, provide a schedule of assumptions used in developing projected or estimated data. As a minimum, state assumptions used for balance sheet, income statement and sales forecast.

Type of Data Shown:
_X_Projected Test Year Ended 12/31/14
___Prior Year Ended 12/31/13
___Historical Year Ended 12/31/12
Witness: See Below

II. OPERATING ASSUMPTIONS
A. INCOME STATEMENT

(1) Line No.	(2) Item	(3) Amount (000's)	(4) Witness	(5) Assumption
1	9. Taxes Other than Income Taxes	$ 111,773	Ritenour Erickson	All taxes other than income taxes are forecasted by applying actual, statutory, or average rates to the applicable tax base. These taxes include Florida Public Service Commission assessment fees, real and personal property taxes, gross receipts tax, franchise fees, state and federal unemployment tax, FICA, state motor vehicle licenses, federal highway use tax, and miscellaneous state and local taxes. The total amount is then reduced for taxes capitalized and taxes applicable to motor vehicles.
7	10. Federal and State Income Taxes	$ 67,168	Ritenour Erickson	Currently applicable federal and state income tax regulations are followed. The lowest possible tax payments are made currently. Assumptions include: - Federal tax rate = 35% - Full normalization of book and tax timing and basis differences - Current IRS rules are followed - State tax rate = 5.5% - State of Florida tax regulations utilized
14	11. AFUDC - Debt and Equity	$ 19,082	Ritenour	AFUDC Rate: 6.26% The AFUDC rate is calculated based on a 13-month average jurisdictional capital structure and is input into a compounding formula to arrive at the monthly AFUDC rate. The monthly rate is applied to the projected average monthly eligible CWIP balance.
18	12. Earnings on Temporary Cash	$ -	Ritenour	The projected amount is calculated by applying the applicable forecasted interest rate to the projected average monthly balance of temporary cash investments.
20	13. Other Income	$ 949	Ritenour	The projected amount includes the earnings on the funded portion of the property insurance reserve, as well as the projected earnings on the company's surge product activity.
23	14. Other Income Deductions	$ 4,139	Ritenour	The projected amount includes donations, civic membership, governmental expenses, and the amortization of Non-electric Investment Tax Credits.
25	15. Income Taxes on Other Income	$ (921)	Ritenour Erickson	Currently applicable federal and state income tax regulations are followed. The lowest possible tax payments are made currently. See item 10 of this section for assumptions.

27 Totals may not add due to rounding.

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FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: For a projected test year, provide a schedule of assumptions used in developing projected or estimated data. As a minimum, state assumptions used for balance sheet, income statement and sales forecast.

Type of Data Shown:
_X_ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
___ Historical Year Ended 12/31/12
Witness: See Below

II. OPERATING ASSUMPTIONS
A. INCOME STATEMENT

(1) Line No.	(2) Item	(3) Amount (000's)	(4) Witness	(5) Assumption
1	16. Interest on Long-Term Debt	$ 52,010	Ritenour	The projected amount is calculated by applying the coupon interest rate to the bond principal and dividing by 12. The calculation is adjusted for any new issues and scheduled retirements.
4	17. Interest on Pollution Control Debt	$ 9,532	Ritenour	The projected amount is calculated by applying the coupon interest rate to the bond principal and dividing by 12. The calculation is adjusted for any new issues and scheduled retirements.
7	18. Interest on Short-term Debt	$ 416	Ritenour	The projected amount is calculated by applying the forecasted short-term interest rates, as described in Section I.C. of this schedule, to the face amount of short-term debt projected to be outstanding.
10	19. Amortization of Debt Discount, Premium and Expense	$ 2,400	Ritenour	The projected amount is calculated based on the embedded amortization amounts. No adjustments are made for new debt issues. The interest rate on new debt issues is projected to include the effect of debt-related costs over the life of the debt issued.
13	20. Other Interest Expense	$ 814	Ritenour	The projected amount is calculated based on applying the budgeted rate to the projected average monthly balance of Customer Deposits.
15	21. Preference Dividends	$ 8,880	Ritenour	The projected amount is calculated by multiplying each preference principal by its dividend rate and dividing by 12. The calculation is adjusted for any new issues and scheduled retirements.
18	22. Net Income After Dividends on Preference Stock	$ 107,556		

20 Totals may not add due to rounding.

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: For a projected test year, provide a schedule of assumptions used in developing projected or estimated data. As a minimum, state assumptions used for balance sheet, income statement and sales forecast.

Type of Data Shown:
_X_ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
___ Historical Year Ended 12/31/12
Witness: R. W. Grove

II. OPERATING ASSUMPTIONS
B. AVERAGE ANNUAL NET UNIT HEAT

(1) Line No.	(2) Unit	(3) Average Net Heat Rates (BTU/KWH)
1	CRIST 4	11,981
2	CRIST 5	11,562
3	CRIST 6	11,553
4	CRIST 7	11,091
5	SCHOLZ 1	13,017
6	SCHOLZ 2	13,515
7	SMITH 1	10,524
8	SMITH 2	10,754
9	SMITH 3	7,145
10	SMITH A	0
11	DANIEL 1	10,576
12	DANIEL 2	10,634
13	PEA RIDGE 1	15,000
14	PEA RIDGE 2	15,000
15	PEA RIDGE 3	15,000
16	PERDIDO 1	9,900
17	PERDIDO 2	9,900

18 Totals may not add due to rounding.

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: For a projected test year, provide a schedule of assumptions used in developing projected or estimated data. As a minimum, state assumptions used for balance sheet, income statement and sales forecast.

Type of Data Shown:
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Witness: R. W. Grove

II. OPERATING ASSUMPTIONS
C. OUTAGE RATES FOR PROJECTED TEST YEAR

(1) Line No.	(2) Unit	(3) Equivalent Forced Outage Rate %
1	CRIST 4	1.0%
2	CRIST 5	1.0%
3	CRIST 6	4.0%
4	CRIST 7	4.0%
5	SCHOLZ 1	0.3%
6	SCHOLZ 2	1.2%
7	SMITH 1	2.1%
8	SMITH 2	1.8%
9	SMITH 3	0.8%
10	SMITH A	0.0%
11	DANIEL 1	3.7%
12	DANIEL 2	3.6%
13	PEA RIDGE 1	3.7%
14	PEA RIDGE 2	3.7%
15	PEA RIDGE 3	3.7%
16	PERDIDO 1	1.4%
17	PERDIDO 2	1.4%

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FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: For a projected test year, provide a schedule of assumptions used in developing projected or estimated data. As a minimum, state assumptions used for balance sheet, income statement and sales forecast.

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Witness: R. W. Grove

II. OPERATING ASSUMPTIONS

D. PLANNED MAINTENANCE FOR PROJECTED TEST YEAR

(1) Line No.	(2) Unit	(3) Start Date	(4) End Date	(5) Outage Duration (Days)	(6) Total Days
1	CRIST 4	04/12/14	05/11/14	30	30
2	CRIST 5	04/12/14	05/11/14	30	30
3	CRIST 6	09/20/14	11/16/14	58	58
4	CRIST 7	No Outage Planned			
5	SCHOLZ 1	No Outage Planned			
6	SCHOLZ 2	No Outage Planned			
7	SMITH 1	No Outage Planned			
8	SMITH 2	No Outage Planned			
9	SMITH 3	04/21/14	04/29/14	9	9
10		10/27/14	11/04/14	9	9
11	SMITH A	No Outage Planned			
12	DANIEL 1	02/08/14	02/16/14	9	9
13		04/12/14	04/20/14	9	9
14		11/15/14	12/28/14	44	44
15	DANIEL 2	02/08/14	04/20/14	72	72
16	PEA RIDGE 1 (a)	N/A	N/A	N/A	N/A
17	PEA RIDGE 2 (a)	N/A	N/A	N/A	N/A
18	PEA RIDGE 3 (a)	N/A	N/A	N/A	N/A
19	PERDIDO 1 (a)	N/A	N/A	N/A	N/A
20	PERDIDO 2 (a)	N/A	N/A	N/A	N/A

21 (a) Quarterly preventative maintenance performed on variable dates and durations.

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FLORIDA PUBLIC SERVICE COMMISSION

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EXPLANATION: For a projected test year, provide a schedule of assumptions used in developing projected or estimated data. As a minimum, state assumptions used for balance sheet, income statement and sales forecast.

Type of Data Shown:
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Witness: R. W. Grove

II. OPERATING ASSUMPTIONS
E. NET UNIT CAPACITY RATINGS FOR PROJECTED TEST YEAR

(1) Line No.	(2) Unit	(3) Net (Summer & Winter)
1	CRIST 4	75
2	CRIST 5	75
3	CRIST 6	299
4	CRIST 7	475
5	SCHOLZ 1	46
6	SCHOLZ 2	46
7	SMITH 1	162
8	SMITH 2	195
9	SMITH 3	556/584
10	SMITH A	32/40
11	DANIEL 1	255
12	DANIEL 2	255
13	PEA RIDGE 1	4/5
14	PEA RIDGE 2	4/5
15	PEA RIDGE 3	4/5
16	PERDIDO 1	1.5
17	PERDIDO 2	1.5

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Witness: See Below

II. OPERATING ASSUMPTIONS

F. OTHER FUEL BUDGET ASSUMPTIONS FOR JANUARY 2014 - DECEMBER 2014

(1) Line No.	(2) Item	(3) Witness	(4) Assumption
1	1. System Generation Expansion Plan	Burroughs	a. Generation Expansion Plan as provided by System Planning.
2			b. Preliminary and commercial operation dates as provided by SCS.
3			c. Unit retirement dates as provided by the operating companies.
4	2. Load and KWH Energy Estimates	Alexander	a. Based on assumptions outlined in Section I.A. of this schedule and as described in direct testimony.
5		Grove	b. Sales to nonassociated companies as estimated by SCS.
6	3. Maintenance Schedules	Grove	Official maintenance schedules as provided to SCS by the operating
7			companies as shown in Section II.D. of this schedule.
8	4. Heat Rates	Grove	Heat rates provided by SCS.
9	5. Coal	Burroughs	a. Beginning Inventory Values as provided by the operating companies.
10			b. Desired plant inventory values as recommended by SCS Fuel Services and approved
11			by the operating companies.
12			c. Coal quality as provided by SCS Fuel Services.
13			d. Beginning prices (See MFR B-18)
14			(1) F.O.B. mine or loaded cost as recommended by SCS Fuel Services and
15			approved by the operating company involved. The actual billing cost
16			and recommended accruals per SCS Contract Administration records
17			for non cost-based contracts and committed spot. These values were
18			adjusted for typical Btu variance from contract values and appropriate
19			state use taxes were added, if applicable.
20			(2) Coal transportation cost on contract and spot as recommended by SCS
21			Fuel Services and approved by the operating company involved.
22			e. Price escalation rates.
23			(1) The escalation rates for contract, uncommitted spot, unknown contract
24			coal, and coal transportation and the timing thereof are reflected as
25			agreed to by the System Planning Coordination Team. These rates
26			include a background inflation forecast as well as a market forecast.

27 Totals may not add due to rounding.

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

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Witness: See Below

II. OPERATING ASSUMPTIONS
F. OTHER FUEL BUDGET ASSUMPTIONS FOR JANUARY 2014 - DECEMBER 2014

(1) Line No.	(2) Item	(3) Witness	(4) Assumption
1	6. Oil	Burroughs	a. Beginning inventory values as provided by the operating companies.
2			b. Desired plant inventory levels for boiler lighter oil as provided by the operating companies.
3			c. Desired plant inventory levels of fuel oil for generation as established in the System Gas and Oil Policy.
4			d. Boiler lighter oil burn: Quantity projected to be burned as recommended by SCS and approved
5			by the operating company involved.
6			e. Oil quality--Btu/gallon and % sulfur content as recommended by SCS and
7			approved by the operating company involved.
8			f. Beginning prices. (See MFR B-18): Delivered prices in cents/MMBtu as recommended by
9			SCS and approved by the company involved.
10			g. Price escalation rates - The escalation rates for oil and the timing thereof are as
11			agreed to by the System Planning Coordination Team. These rates include a background
12			inflation forecast as well as a market forecast.
13	7. Natural Gas	Burroughs	a. Beginning gas storage (inventory) values as provided by the operating companies.
14			b. Desired gas storage levels as established in the System Gas and Oil Policy.
15			c. Natural gas availability - It is assumed that all natural gas required can be
16			obtained for the budget/forecast period.
17			d. Boiler lighter gas burn - Quantity projected to be burned as recommended by SCS and
18			approved by the operating company.
19			e. CC & CT gas burn - For all dual fired units, only natural gas is shown to be burned
20			in the budget/forecast.
21			f. Natural gas quality - Btu/mcf as recommended by SCS and approved by the operating
22			company involved.
23			g. Beginning prices: Delivered prices as recommended by SCS and approved by the
24			operating company involved.
25			h. Price escalation rates - The escalation rates for gas and the timing thereof are as
26			agreed to by the System Planning Coordination Team. These rates include a background
27			inflation forecast as well as a market forecast.

28 Totals may not add due to rounding.

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

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Witness: See Below

III. CAPITAL ADDITIONS ASSUMPTIONS
A. CONSTRUCTION EXPENDITURES

(1) Line No.	(2) Item	(3) Amount (000's)	(4) Witness	(5) Assumption
1	Construction Expenditures		Ritenour	
2	1. Production Plant	$ 302,424	Grove	Proposed additions and retirements of production plant are based on such factors as service life, forced outage rates, performance, operating experience, environmental regulations, technological improvements, obsolescence, additional requirements, etc.
5	2. Transmission	$ 114,936	Caldwell	Transmission project plans are cyclical in nature and reflect the nature of planning and maintaining a reliable and operable system. The increase in capital projects in 2014 reflects that cycle and the current need to maintain the infrastructure to support current and future load conditions along with any planned generation changes.
10	3. Distribution	$ 52,174	McQuagge	Proposed additions include distribution system improvements, asset management, pole inspection and replacement. Continue to fund programs related to system reliability such as investments in Smart Grid technologies and storm hardening upgrades of critical facilities.
13	4. General Plant	$ 8,448	McQuagge	Projected based on the need to replace general plant items such as vehicles, test equipment, tools, office equipment, and communication equipment that are no longer serviceable, and to insure an adequate number of such items are available so that the appropriate personnel can fulfill their job requirements in an effective and efficient manner.
18	5. Total Construction Expenditures	$ 477,982		

19 Totals may not add due to rounding.

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Witness: See Below

III. CAPITAL ADDITIONS ASSUMPTIONS
B. ELECTRIC PLANT IN SERVICE AND ACCUMULATED DEPRECIATION

(1) Line No.	(2) Item	(3) Amount (000's)	(4) Witness	(5) Assumption
1	1. Gross Additions to Plant:		Ritenour	The amounts are based on the 2013 Official Capital Additions Budget as approved by Gulf's management. Plant-in-Service amounts, in-service year, and plant classification were provided by the functional Planning Units.
2	Production	$ 117,378	Grove	
3	Transmission	$ 30,404	Caldwell	
4	Distribution	$ 58,085	McQuagge	
5	General Plant	$ 8,589	Ritenour/McQuagge	
6	Total Gross Additions to Plant	$ 214,456		
7	2. Retirements	$ 21,471	Ritenour	The amount was based on the 2013 Official Capital Additions Budget as approved by Gulf's management. Amounts, dates and function were provided by the functional Planning Units.
8				
9				
10	3. Net Salvage	$ 6,223	Ritenour	The amount was based on the 2013 Official Capital Additions Budget as approved by Gulf's management. Amounts, dates and function were provided by the functional Planning Units.
11				
12				
13	4. Depreciation and Amortization Rates	Various	Ritenour	With the exception of the AMI meter depreciation life of 15 years and non-AMI meter amortization of 8 years, as ordered in Docket No. 110138-EI, and the Perdido Landfill Facility depreciation rate of 5.0% approved by the Commission in Order No. PSC-10-0674-PAA-EI, issued on November 9, 2010 in Docket No. 100368-EI, depreciation and dismantlement expense is based on rates effective January 1, 2010, which were approved by the FPSC through Docket 090319-EI, FPSC Order No. PSC-10-0458-PAA-EI dated July 19, 2010.
14			Erickson	
15	5. Provision for Depreciation and Amortization Expenses	$ 157,904	Ritenour	The amount was projected by applying the FPSC approved rates and amortization amounts to the average monthly balance of depreciable plant by function. This amount is calculated by the Financial Model.
16			Erickson	
17				

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FLORIDA PUBLIC SERVICE COMMISSION

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EXPLANATION: For a projected test year, provide a schedule of assumptions used in developing projected or estimated data. As a minimum, state assumptions used for balance sheet, income statement and sales forecast.

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Witness: See Below

IV. BALANCE SHEET ASSUMPTIONS
A. 13-MONTH AVERAGE ASSETS

(1) Line No.	(2) Item	(3) Amount (000's)	(4) Witness	(5) Assumption
1	Utility Plant			
2 1.	Electric Plant in Service	$ 4,480,719	Ritenour	The projected balances were derived by adding to the balance at December 31, 2012 the projected additions and deducting the projected retirements as described in Section III.B. of this schedule.
5 2.	Electric Plant for Future Use	$ 18,456	Ritenour	The projected balances were derived by adding to the balance at December 31, 2012 the projected additions.
7 3.	Construction Work in Progress	$ 409,402	Ritenour	The projected balances were calculated by adding to the balance at December 31, 2012, the 2013 budgeted construction expenditures through December 2014 and deducting the projected closings to Plant-In-Service as described in Section III.B. of this schedule.
10 4.	Plant Acquisition Adjustment	$ 1,903	Ritenour	The projected balances were calculated by reducing each month's balance by the amount of amortization related to the Plant Acquisition Adjustment. Amortization is $21,276 per month.
13 5.	Accumulated Provision for Depreciation and Amortization	($1,549,548)	Ritenour	The projected balances were calculated by adding to the balance at December 31, 2012, the projected provision for depreciation and net salvage values and deducting the projected retirements budgeted. The provision for depreciation was calculated using the methodology described in Section III.B. of this schedule. Retirements and Net Salvage were based on the 2013 Construction Budget.
18 6.	Net Utility Plant	$ 3,360,932		
19 7.	Other Special Funds	$ 98,654	Ritenour Erickson	The projected balance includes the funded portion of the property insurance reserve, plus interest accrued. The annual funding of the reserve occurs each January. The required funded balance is calculated by applying the effective after tax rate of 61.425% to the projected year-end balance of the property insurance reserve account each December. An additional amount necessary to achieve this balance is funded in January. The balance also includes the projected balance of the prepaid pension. The projected pension balance was derived by adding the projected annual accrual to the balance at December 31, 2012.
25 8.	Non-Utility Property	$ 13,029	Ritenour	The projected balance was based on the actual balance at December 31, 2012 with adjustments made for additions through December 31, 2014.

27 Totals may not add due to rounding.

FLORIDA PUBLIC SERVICE COMMISSION

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Witness: See Below

IV. BALANCE SHEET ASSUMPTIONS
A. 13-MONTH AVERAGE ASSETS

(1) Line No.	(2)	Item	(3) Amount (000's)	(4) Witness	(5) Assumption
1		Utility Plant cont.			
2 3	9.	Other Property and Investments-Other	$ 2,598	Ritenour	The projected balance was based on the actual balance at December 31, 2012 adjusted for projections for the Deferred Compensation Trust.
4	10.	Total Other Property and Investments	$ 114,281		
5		Current Assets			
6 7	11.	Cash	$ 6,011	Ritenour	The projected balance is maintained as a static balance by the Financial Model as an estimate that approximates operating cash requirements.
8 9	12.	Special Deposits	$ 18	Ritenour	The projected balance was based on the actual balance at December 31, 2012. No changes were projected for the test year.
10 11	13.	Working Funds	$ 378	Ritenour	The projected balance was based on the actual balance at December 31, 2012. No changes were projected for the test year.
12 13 14	14.	Temporary Cash Investments	$ 0	Ritenour	The projected balance is calculated by the Financial Model based on the projected sources and uses of funds. No balances are projected for the test year.
15 16 17	15.	Customer Accounts Receivable	$ 76,042	Ritenour	The projected balance was derived based on the December 31, 2012 actual balance, with changes forecasted based on a percentage of billed revenues during the period.
18 19	16.	Accrued Unbilled Revenue	$ 54,643	Ritenour	The projected balance was derived based on the December 31, 2012 actual balance adjusted for monthly net increase or decrease in unbilled revenue.
20 21	17.	Other Accounts and Notes Receivable	$ 12,455	Ritenour	The projected balance was derived based on December 31, 2012 actual balance adjusted for the monthly increase or decrease in receivables.

22 Totals may not add due to rounding.

FLORIDA PUBLIC SERVICE COMMISSION

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Witness: See Below

IV. BALANCE SHEET ASSUMPTIONS
A. 13-MONTH AVERAGE ASSETS

(1) Line No.	(2) Item	(3) Amount (000's)	(4) Witness	(5) Assumption
1 2	18. Accumulated Provisions for Uncollectible Accounts	$ (1,740)	Ritenour	The projected balance was calculated by applying a historical ratio for uncollectibles to the monthly customer accounts receivable balance.
3 4 5	19. Receivables from Associated Companies	$ 13,374	Ritenour	The projected balance includes the Interchange transactions when Gulf is a net seller to the Southern Company pool, and an estimate of other miscellaneous receivables from associated companies.
6 7 8	20. Interest and Dividends Receivable	$ 25	Ritenour	Interest and Dividends Receivable is forecasted based on the projected temporary cash investment rate, based upon a market forecast by Moody's Analytics, multiplied by the funded portion of the forecasted property insurance reserve balance.
9 10	21. Fuel Stock	$ 91,848	Ritenour Burroughs	The projected balance is a function of the Fuel Budget as described in MFR F-5.
11 12 13 14 15 16 17 18 19 20 21 22	22. In-Transit Coal	$ 11,381	Ritenour Burroughs	The monthly projected tons of in transit coal inventory for Plants Crist and Smith is comprised of projected train shipments in route (not received at the transloading/blending facilities), operational coal inventory located at the transloading/blending facilities, loaded barges in route to the plants, and loaded barges waiting to be unloaded by the plants. The value of this in transit inventory is calculated by multiplying the projected tons in transit by the weighted average price of coal F.O.B. the barge for all coal shipments projected to occur during the year. The monthly projected tons of in transit coal inventory for Plants Daniel, Scholz, and Scherer is comprised of the prior 12 month actual average quantity (tons) of train shipments in route, not received at plant. The value of this in transit inventory for each plant is calculated by multiplying the projected tons in transit by the weighted average delivered price of coal for all coal shipments projected to occur to the respective plant during the year.
23 24 25 26	23. Plant Materials and Supplies	$ 60,376	Ritenour	The projected materials and supplies balance was derived based on historical and projected balances developed by the Procurement and Purchasing Department and the Power Delivery Department. The allowance inventory balances are based on generation.
27 28	24. Prepayments	$ 16,734	Ritenour	The projected balance was based on estimated insurance premiums and related amortization, long term service agreement, and other miscellaneous prepayments.

29 Totals may not add due to rounding.

Supporting Schedules: B-3, B-7, B-9

Recap Schedules: B-1, C-1

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Witness: See Below

IV. BALANCE SHEET ASSUMPTIONS
A. 13-MONTH AVERAGE ASSETS

(1) Line No.	(2) Item	(3) Amount (000's)	(4) Witness	(5) Assumption
1	25. Miscellaneous Current & Accrued	$ 4,357	Ritenour	The projected balance was based on the actual balance at December 31, 2012. No changes were projected for the test year.
3	26. Total Current Assets	$ 345,902		
4	Deferred Debits			
5	27. Unamortized Debt Expense	$ 7,455	Ritenour	The projected balance was derived based on the actual balance at December 31, 2012 reduced by monthly net amortization based on the embedded expenses.
7	28. Accumulated Deferred Income Taxes	$ 76,615	Ritenour Erickson	The projected balance was derived based on the actual balance at December 31, 2012 adjusted for the projected provisions and pay backs related to the property damage reserve, injuries and damages reserve, bad debt reserve, emission allowances, deferred revenues, and certain employee benefits.
11	29. Regulatory Tax Asset	$ 52,417	Ritenour Erickson	This amount is based on the actual balance at December 31, 2012, adjusted for estimated changes. This account appears on the balance sheet in compliance with FAS 109.
14	30. Unamortized Loss on Reacquired Debt	$ 14,387	Ritenour	The projected balance was derived based on the actual balance at December 31, 2012 reduced by monthly amortization.
16	31. Other Deferred Debits	$ 468,604	Ritenour	The projected balance was based on the actual balance at December 31, 2012 adjusted for the projected changes. This account includes preliminary survey investigation charges and miscellaneous other deferred debit items.
19	32. Total Deferred Debits	$ 619,478		
20	33. Total Assets	$ 4,440,593		

21 Totals may not add due to rounding.

Supporting Schedules: B-3, B-7, B-9

Recap Schedules: B-1, C-1

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

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Witness: S. D. Ritenour

IV. BALANCE SHEET ASSUMPTIONS
B. 13-MONTH AVERAGE CAPITALIZATION AND LIABILITIES

(1) Line No.	(2) Item	(3) Amount (000's)	(4) Witness	(5) Assumption
1	Capitalization			
2	1. Common Stock	$ 393,060	Ritenour	The projected balance was based on the December 31, 2012 actual balance. No changes were projected for the test year.
4	2. Other Paid-In Capital	$ 711,929	Ritenour	The projected balance was derived based on the actual balance at December 31, 2012 adjusted for the projected capital contribution from Southern Company as described in Section I.C. of this schedule.
7	3. Premium on Preference Stock	$ (2,002)	Ritenour	The projected balance was based on the December 31, 2012 actual balance. No changes were projected for the test year.
9	4. Retained Earnings	$ 226,986	Ritenour	The projected balance was derived based on the December 31, 2012 actual balance increase by the projected net income before preference less common and preference stock dividends declared.
12	5. Preference Stock	$ 150,000	Ritenour	The projected balance was derived based on the actual balance at December 31, 2012 adjusted for any projected retirements or issues of preference stock as outlined in Section I.C. of this schedule. There are no new issues of Preference Stock projected for the test year.
16	6. First Mortgage Bonds	$ 0	Ritenour	There is no projected balance for this item in the test year.
18	7. Pollution Control Liability	$ 308,955	Ritenour	The projected balance was derived based on the actual balance at December 31, 2012 adjusted for scheduled retirements as described in Section I.C. of this schedule. There are no new Pollution Control Liability issues projected for the test year.
21	8. Other Long Term Debt	$ 1,003,462	Ritenour	The projected balance was derived based on the actual balance at December 31, 2012 adjusted for projected issues and retirements as described in Section I. C. of this schedule.
23	9. Unamortized Debt Discount and Premium	$ (7,217)	Ritenour	The projected balance was derived based on the December 31, 2012 actual balance reduced by the monthly net amortization of discounts and premiums.
25	10. Total Capitalization	$ 2,785,173		

26 Totals may not add due to rounding.

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___ Prior Year Ended 12/31/13
___ Historical Year Ended 12/31/12
Witness: See Below

IV. BALANCE SHEET ASSUMPTIONS
B. 13-MONTH AVERAGE CAPITALIZATION AND LIABILITIES

(1) Line No.	(2) Item	(3) Amount (000's)	(4) Witness	(5) Assumption
1	Current Liabilities			
2	11. Notes Payable	$ 51,663	Ritenour	The projected balance was calculated by the Financial Model based on the projected sources and uses of funds.
4	12. Construction Related Accounts Payable	$ 11,956	Ritenour	The projected balance was derived by applying a historical five year average ratio to monthly construction expenditures (less Plant Scherer expenditures). This account includes accounts payable - construction and contract retentions.
8	13. Other Accounts Payable	$ 60,757	Ritenour	The projected balance was derived using historical accounts payable ratios to fuel and other operations and maintenance expense applied to projected expenses for those accounts. Also included in this account is the monthly unaudited accounts payable invoices dealing with plant accounts.
13	14. Payables to Associated Companies	$ 38,012	Ritenour	The projected balance was derived by applying historical accounts payable ratios to fuel and other operations and maintenance expenses associated with co-owned plants plus monthly interchange transactions when Gulf is a net purchaser from the Southern Company pool.
17	15. Customer Deposits	$ 35,350	Ritenour Erickson	The projected balance was derived by calculating a customer change rate based upon projected customer counts and applying that rate to the prior balance in Customer Deposits to derive a monthly change in balance.

20 Totals may not add due to rounding.

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO. 130140-EI

EXPLANATION: For a projected test year, provide a schedule of assumptions used in developing projected or estimated data. As a minimum, state assumptions used for balance sheet, income statement and sales forecast.

Type of Data Shown:
_X_Projected Test Year Ended 12/31/14
___Prior Year Ended 12/31/13
___Historical Year Ended 12/31/12
Witness: See Below

IV. BALANCE SHEET ASSUMPTIONS
B. 13-MONTH AVERAGE CAPITALIZATION AND LIABILITIES

(1) Line No.	(2) Item	(3) Amount (000's)	(4) Witness	(5) Assumption
1	16. Taxes Accrued	$ 19,012	Ritenour Erickson	The projected balance was derived based on the December 31, 2012 actual balance plus projected monthly accruals from the income statement reduced by the estimated tax payments.
4	17. Interest Accrued	$ 13,378	Ritenour	The projected balance was calculated based on the interest rate and payment dates of embedded debt issues as of December 31, 2012 plus any issues or retirements. This account also includes amounts related to the interest on customer deposits.
8	18. Miscellaneous Accounts Payable	$ 0	Ritenour	There is no projected balance for this item in the test year.
10	19. Tax Collections Payable	$ 1,218	Ritenour	The projected balance was based on the historical relationship of taxes to their applicable base and a historical average for payroll taxes.
12	20. Accrued Vacations	$ 9,673	Ritenour	The projected balance was based on an analysis by the payroll department taking into account the number of employees, years of service and hourly rates.
15	21. Other Current Liabilities	$ 64,379	Ritenour	The projected balance was based on a 12-month historical average and adjusted for projected changes, combined with the projected dividends declared.
17	22. Total Current Liabilities	$ 305,398		

18 Totals may not add due to rounding.

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: For a projected test year, provide a schedule of assumptions used in developing projected or estimated data. As a minimum, state assumptions used for balance sheet, income statement and sales forecast.

Type of Data Shown:
_X_ Projected Test Year Ended 12/31/14
___ Prior Year Ended 12/31/13
___ Historical Year Ended 12/31/12
Witness: See Below

IV. BALANCE SHEET ASSUMPTIONS
B. 13-MONTH AVERAGE CAPITALIZATION AND LIABILITIES

(1) Line No.	(2) Item	(3) Amount (000's)	(4) Witness	(5) Assumption
1	Deferred Credits			
2	24. Unamortized Investment Tax Credits	$ 3,492	Ritenour Erickson	The projected balance was derived using the actual balance at December 31, 2012 reduced by the amortization of ITC based on the useful life of the asset giving rise to the tax credit.
5	25. Other Deferred Credits	$ 277,170	Ritenour	The projected balance was derived based on the actual balance at December 31, 2012 and the estimated monthly changes. This account includes deferred revenue on pole attachment rentals, and miscellaneous other deferred credit items.
9	26. Total Deferred Credits	$ 280,662		
10	27. Operating Reserves	$ 281,257	Ritenour	The projected balance was based on an estimate of the amounts needed to cover future contingencies.
12	28. Other Deferred Income Taxes	$ 783,584	Ritenour Erickson	The projected balance was derived based on the actual balance at December 31, 2012 adjusted for the projected provisions and paybacks related to loss on reacquired debt, certain employee benefits and the property related depreciation timing differences.
16	29. Regulatory Tax Liability	$ 4,519	Ritenour Erickson	This amount is based on the actual balance at December 31, 2012 adjusted for estimated changes. This account appears on the balance sheet in compliance with FAS 109.
19	30. Total Other Deferred	$ 788,103		
20	31. Total Capitalization and Liabilities	$ 4,440,593		

21 Totals may not add due to rounding.

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 130140-EI

EXPLANATION: Supply a proposed public notice of the company's request for a rate increase suitable for publication.

Type of Data Shown:
_X_Projected Test Year Ended 12/31/14
____Prior Year Ended 12/31/13
____Historical Year Ended 12/31/12
Witness: R. S. Teel

Line No.

On July 12, 2013, Gulf Power Company filed with the Florida Public Service Commission a request for approval to increase the Company's annual retail revenues. Currently, Gulf Power's residential price is lower than prices set in 2009. The proposed request, if approved, would increase the total bill in April 2014 for a residential customer buying 1,000 kilowatt-hours by $8.94 per month or 7.5 percent - from $118.88 to $127.82. The Company is requesting an additional increase in 2015 for transmission investment caused by mandatory federal environmental compliance requirements.

This filing can be found under Docket number 130140-EI.

The main reason for this request is that major investments have been made to maintain our electric system, to strengthen our existing infrastructure and to add new transmission lines. Gulf Power also must make investments in order to meet new mandatory federal environmental regulations. The increase that would take effect in 2015 is for compliance with new federal environmental regulations. This includes certain transmission lines put in place and control systems needed to meet more stringent federal regulations.

From 2012 through 2014, we are investing about $600 million dollars on maintenance, improvements and key transmission projects. These improvements are necessary to continue to provide reliable service to customers.

The present rates will remain in effect until new rates become operative under Florida Law. Copies of the rate case filing, including proposed rate schedules, are available for inspection at your local Gulf Power office. Company personnel are available at all Gulf Power offices to answer questions concerning this request. They may be contacted at the address or telephone number shown on your electric service bill.

For your information, we are providing contact information for the Florida Public Service Commission's Consumer Affairs Department.

Consumer Affairs Department
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0859
1-800-342-3552

The PSC will also accept faxes and emails.
Fax number: 1-800-511-0809
Email address: contact@psc.state.fl.us

Supporting Schedules: Recap Schedules:

Responsibility for Minimum Filing Requirements

Schedule	Title
C-6	Budgeted Versus Actual Operating Revenues and Expenses
C-9	Five Year Analysis - Change in Cost
C-11	Uncollectible Accounts
C-12	Administrative Expenses
C-41	O&M Benchmark Variance by Function
E-7	Development of Service Charges
F-8	Assumptions

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130140-EI EXHIBIT 4
PARTY Gulf Power Company (Gulf) Direct
DESCRIPTION Margaret D. Neyman (MDN-1)

Gulf's FPSC Complaint Activity

Year	Complaint[1]	GI-72[2]	Warm Transfer[3]	Infraction[4]
2002	31	18	96	0
2003	12	23	141	0
2004	9	34	164	0
2005	7	32	139	0
2006	10	23	150	0
2007	7	20	163	0
2008	8	23	313	0
2009	8	36	544	0
2010	17	43	530	1[5]
2011	11	19	436	0
2012	6	9	332	0

[1]Any customer of a Commission regulated company may file a Complaint with the Division of Service, Safety and Consumer Assistance whenever the customer has an unresolved dispute with the company regarding a service that is subject to Commission jurisdiction.

[2]GI-72 is defined as a complaint that is resolved by the Company within three days. If the customer does not object to Company's resolution to the complaint, the complaint will not be reported in the total number of complaints shown in the Commission's Consumer Complaint Activity Report.

[3] Warm Transfer is defined as a customer complaint that is transferred to the utility for resolution via the telephone transfer-connect or e-transfer process.

[4] Infraction is defined as an apparent rule violation.

[5] Infraction is included in the Inquiry total.

CUSTOMER ACCOUNTS ($000)

Category	2013 Budget	2014 Forecast
Customer Service Expense	19,845	20,454
Metering Expense	1,520	1,533
Uncollectible Accounts Expense	3,233	3,808
Customer Accounts Total	**24,598**	**25,795**

CUSTOMER ACCOUNTS ($000)

Test Year Adjusted Benchmark	26,289
Test Year Adjusted Request	25,795
System Benchmark Variance	**(494)**

CUSTOMER ACCOUNTS ($000)

Category	2013 Bud	2014 Fcst	2015 Fcst	2016 Fcst	2017 Fcst
Customer Service Expense	**19,845**	**20,454**	**21,095**	**21,746**	**22,298**
Metering Expense	**1,520**	**1,533**	**1,547**	**1,569**	**1,591**
Uncollectible Accounts Expense	**3,233**	**3,808**	**3,965**	**4,280**	**4,465**
Customer Accounts Total	**24,598**	**25,795**	**26,607**	**27,595**	**28,354**

SERVICE FEES

	Service	Current Cost	Current Fee	New Fee
1	Connection of Initial Service			
	- Residential	$37.40	$27	$27
	- Non Residential	$76.40	$27	$50
2	Connection of Existing Service			
	- Residential	$29.49	$27	$27
	- Non Residential	$108.15	$27	$50
3	Restoration of Service (After Violation of Rules)	$64.80	$35	$60
4	Restoration of Service After Hours (After Violation of Rules)	$76.02	$55	$80
5	Restoration of Service at Pole (After Violation of Rules)	$94.17	$95	$100
6	Premises Visit	$33.47	$20	$30
7	Connection of Temporary Service	$120.29	$110	$110
8	Investigation of Unauthorized Use - FSR	$70.83	$75	$75
9	Returned Items			
	- for Amounts > $300	---	$40.00	$40.00
	- for Amounts > $50 < $300	---	$30.00	$30.00
	- for Amounts < $50	---	$25.00	$25.00

Responsibility for Minimum Filing Requirements

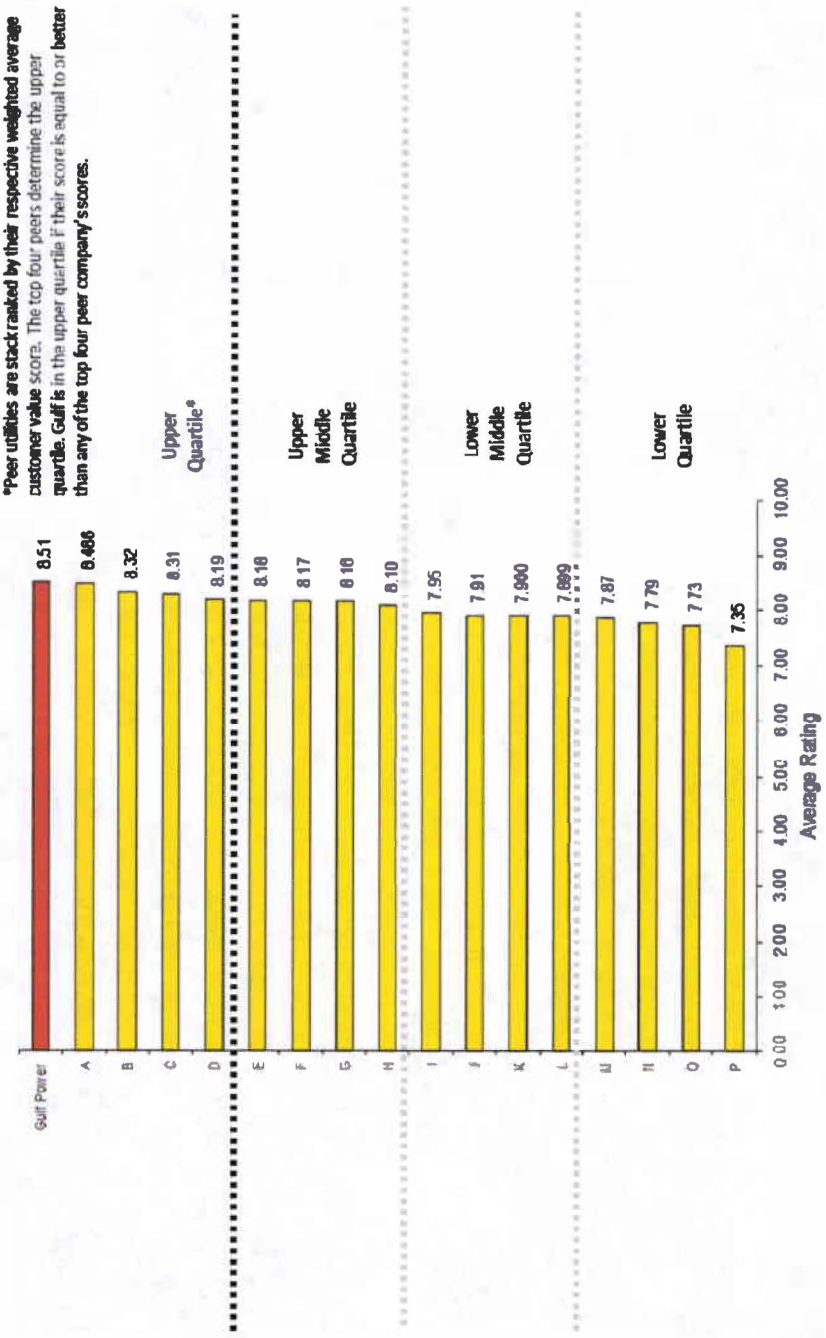
Schedule	Title
C-6	Budgeted Versus Actual Operating Revenues and Expenses
C-9	Five Year Analysis – Change in Cost
C-12	Administrative Expenses
C-14	Advertising Expenses
C-41	O&M Benchmark Variance by Function
F-8	Assumptions

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130140-EI EXHIBIT 5
PARTY Gulf Power Company (Gulf) Direct
DESCRIPTION Angela Strickland (AGS-1)

Customer Value Benchmark Peer Utilities

1. AEP
2. Dominion Resources
3. Duke Energy
4. Entergy
5. Exelon
6. MEAG
7. NextEra Energy (FPL)
8. Oglethorpe
9. PPL
10. Progress Energy
11. Reliant Energy
12. SCANA
13. TECO
14. TVA
15. TXU
16. WE Energies

Customer Value Benchmark - Overall Rank Chart



Customer Service and Information
Expense Detail ($000)

	2013	2014	2015	2016	2017
Supervison	1,877	1,829	1,897	1,949	1,991
Customer Programs and Services	13,314	13,583	13,802	14,048	14,243
Advertising	1,233	1,232	1,235	1,237	1,238
Total	16,424	16,644	16,934	17,234	17,472

Sales
Expense Detail ($000)

	2013	2014	2015	2016	2017
Administrative Expenses	481	491	508	523	536
Programs and Incentives	680	680	680	680	680
Total	1,161	1,171	1,188	1,200	1,213

Customer Service and Information
Test Year Benchmark versus 2014 Budget
($000)

	Benchmark	2014 Budget	Variance
Supervision	3,031	1,829	(1,202)
Customer Programs and Services	15,968	13,581	(2,387)
Advertising	1,213	1,234	21
Total	20,212	16,644	(3,568)

Sales
Test Year Benchmark versus 2014 Budget
($000)

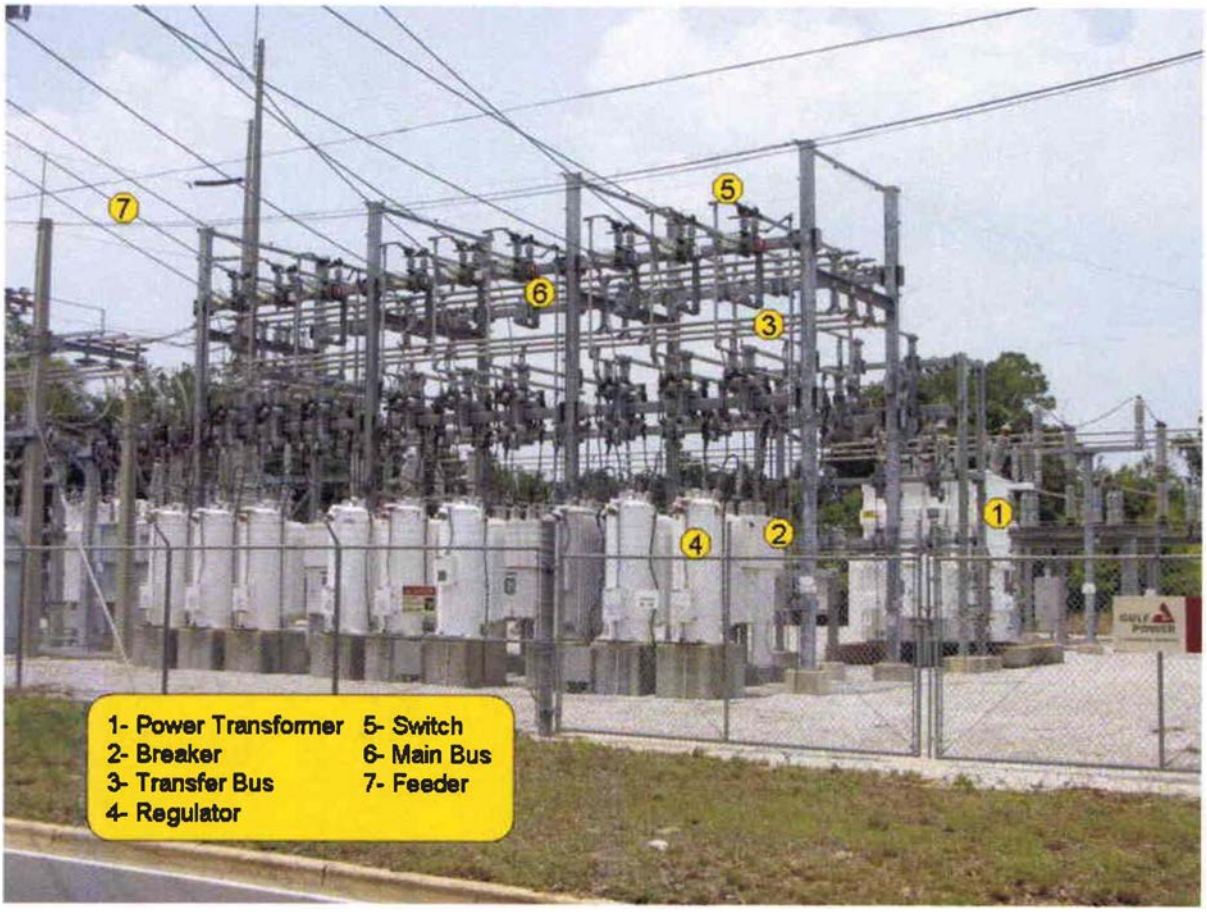
	Benchmark	2014 Budget	Variance
Administration	365	491	126
Programs and Incentives	648	680	32
Total	1,013	1,171	158

Responsibility for Minimum Filing Requirements

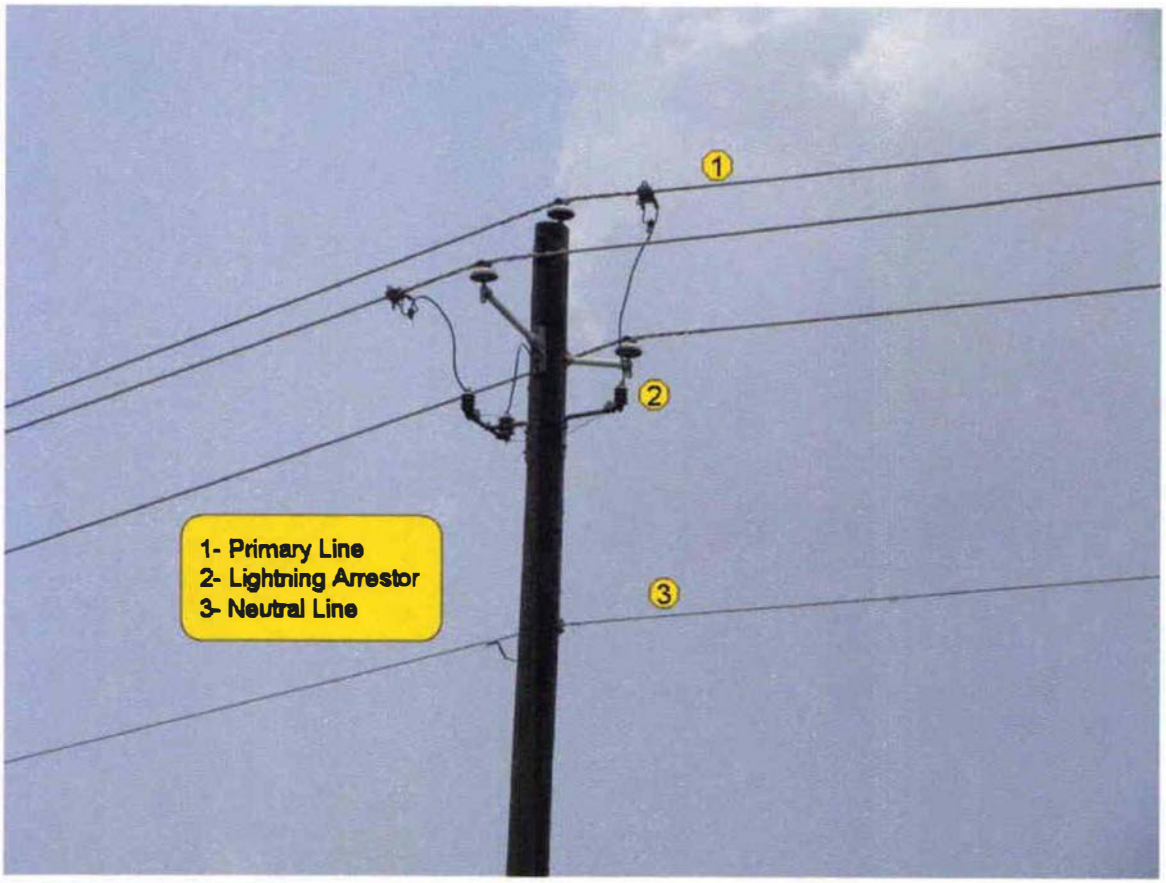
Schedule	Title
C-6	Budgeted Versus Actual Operating Revenues and Expenses
C-8	Detail of Changes in Expenses
C-34	Statistical Information
C-41	O&M Benchmark Variance by Function
F-8	Assumptions

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130140-EI EXHIBIT 6
PARTY Gulf Power Company (Gulf) Direct
DESCRIPTION Andy McQuagge (JAM-1)

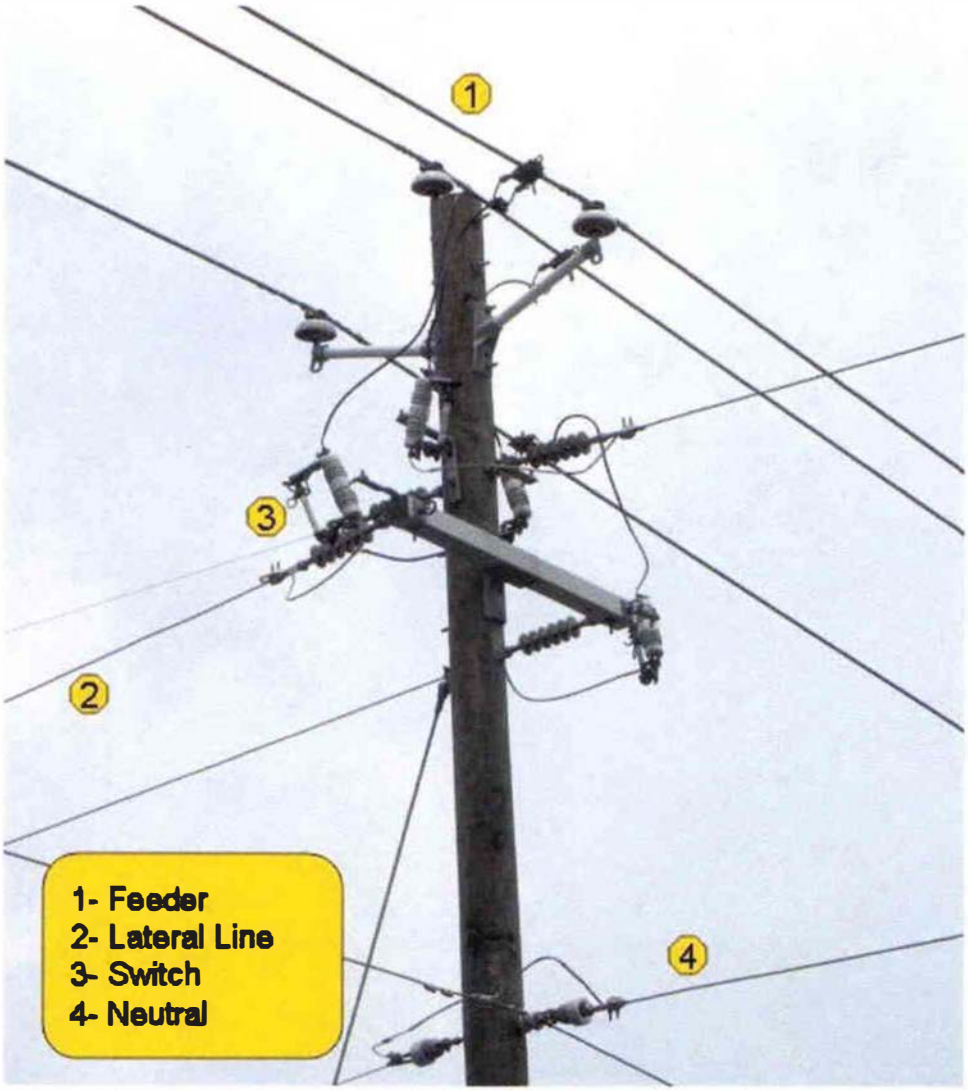
Distribution Substation



Feeder

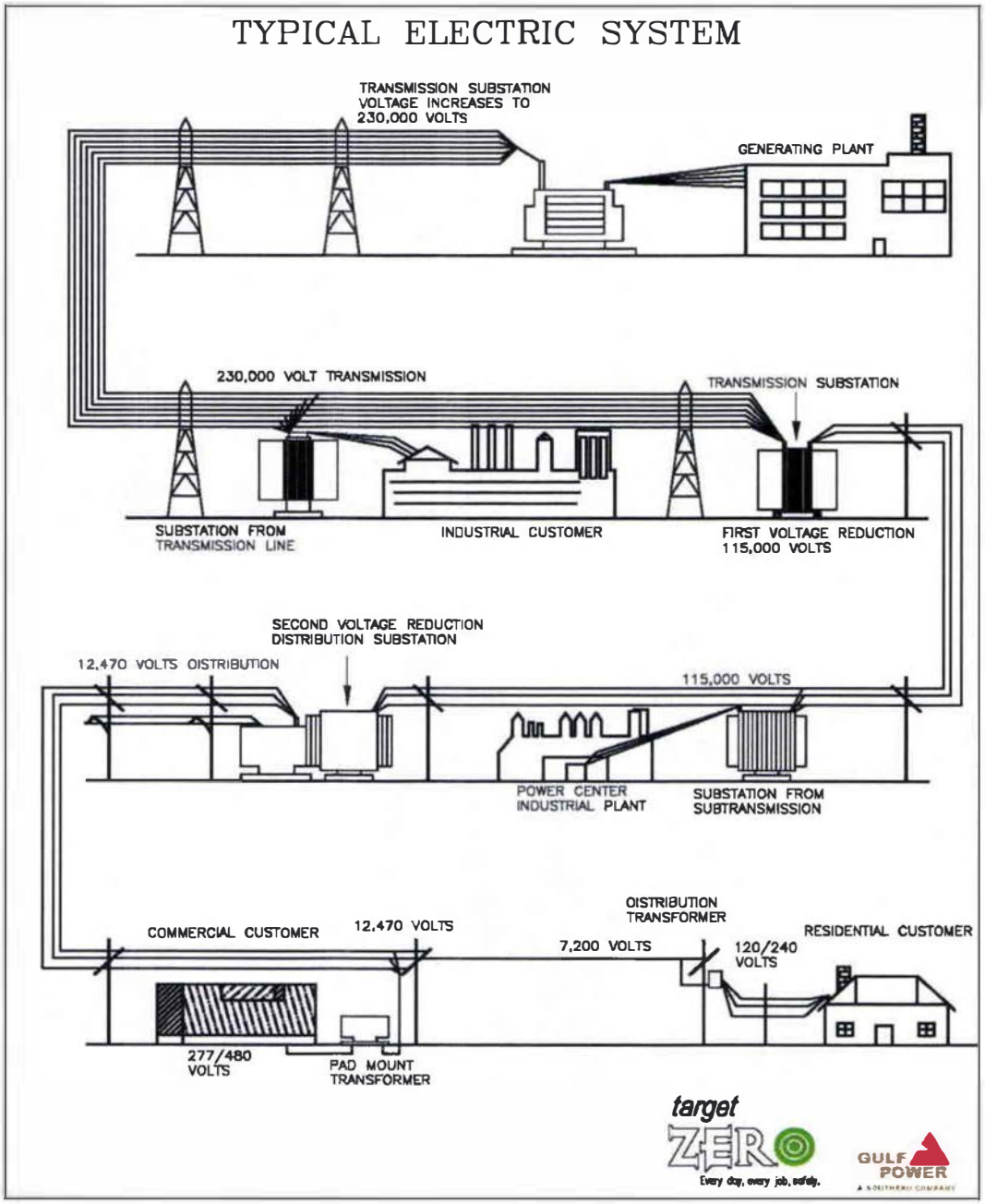


Lateral Lines



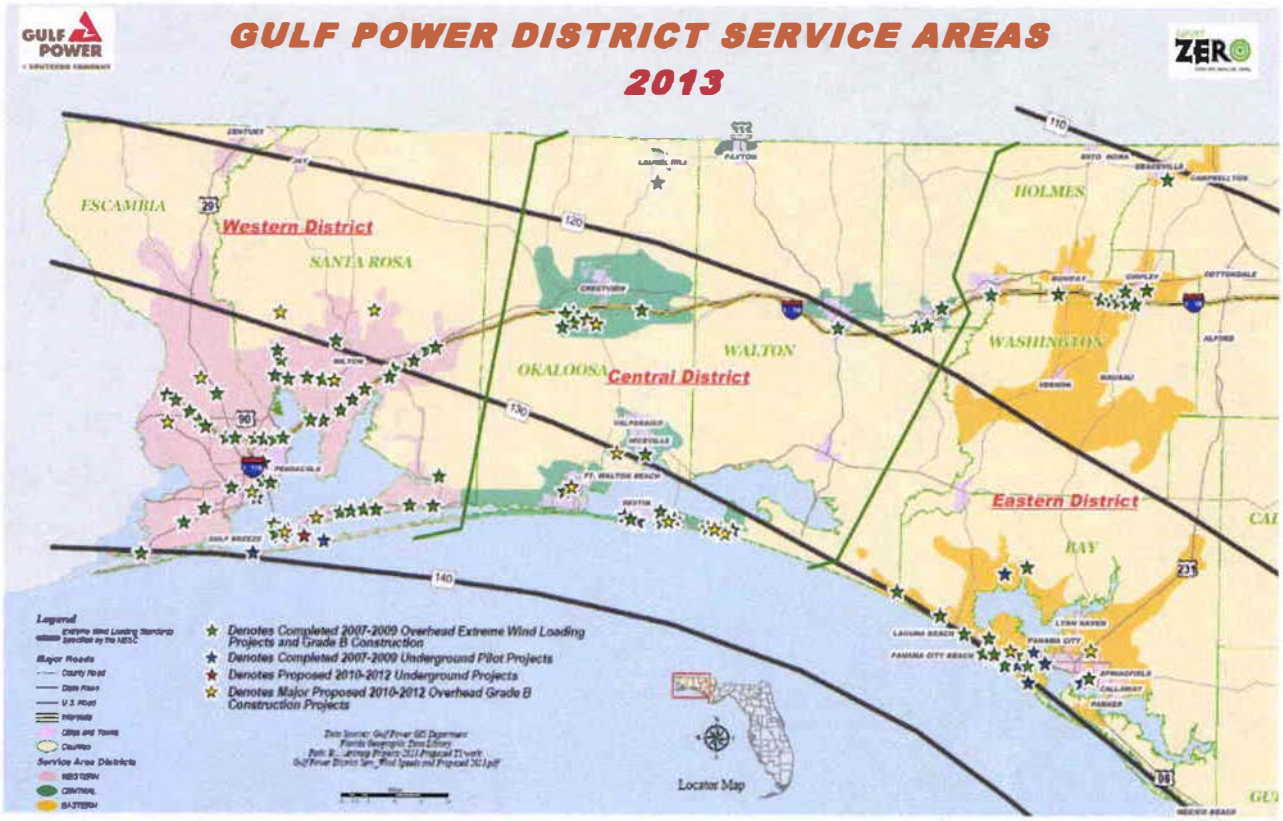
Florida Public Service Commission
Docket No. 130140-EI
GULF POWER COMPANY
Witness: J. Andy McQuagge
Exhibit No. ____ (JAM-1)
Schedule 3
Page 1 of 1

Electric Power Grid

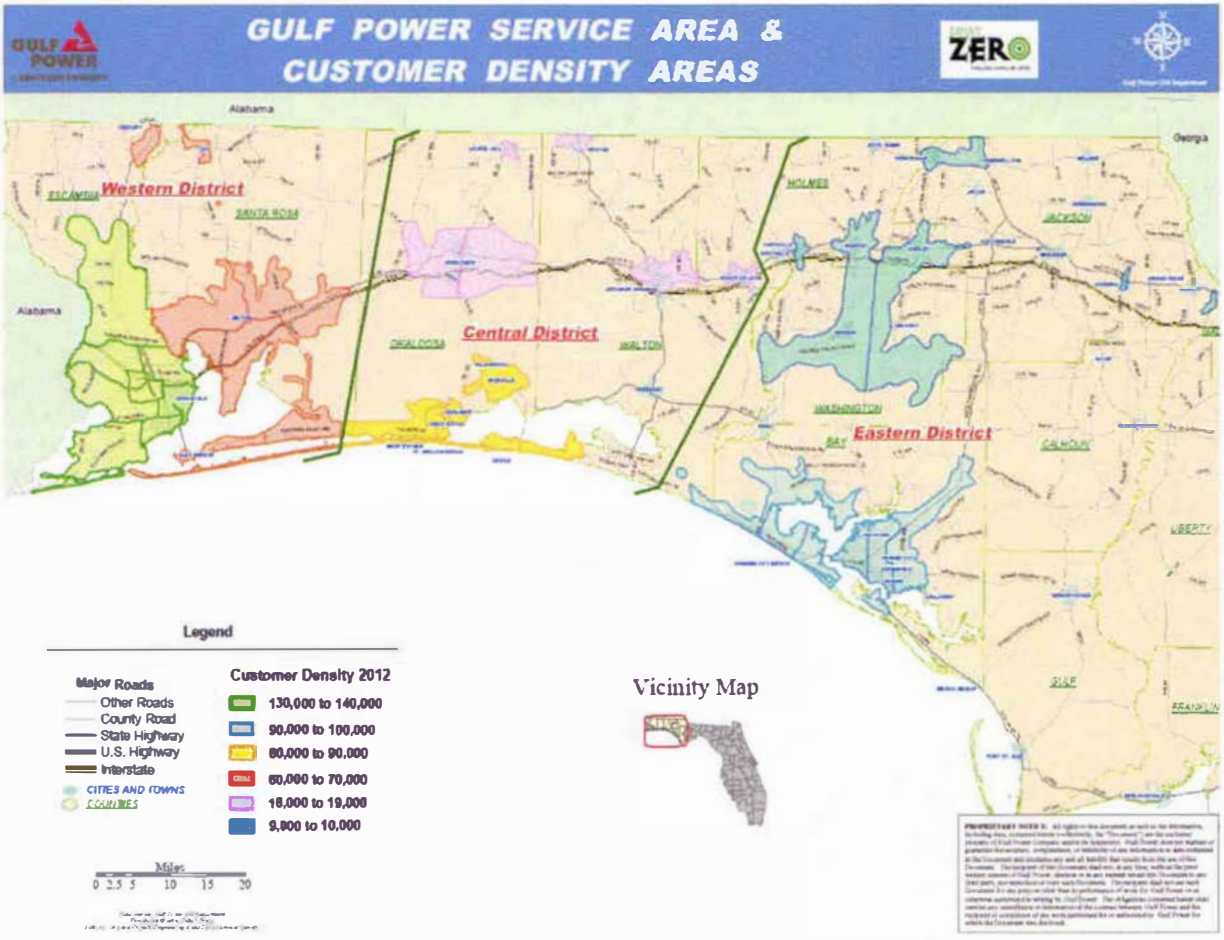


Florida Public Service Commission
Docket No. 130140-EI
GULF POWER COMPANY
Witness: J. Andy McQuagge
Exhibit No. ____ (JAM-1)
Schedule 4
Page 1 of 1

Gulf Power District Service Areas

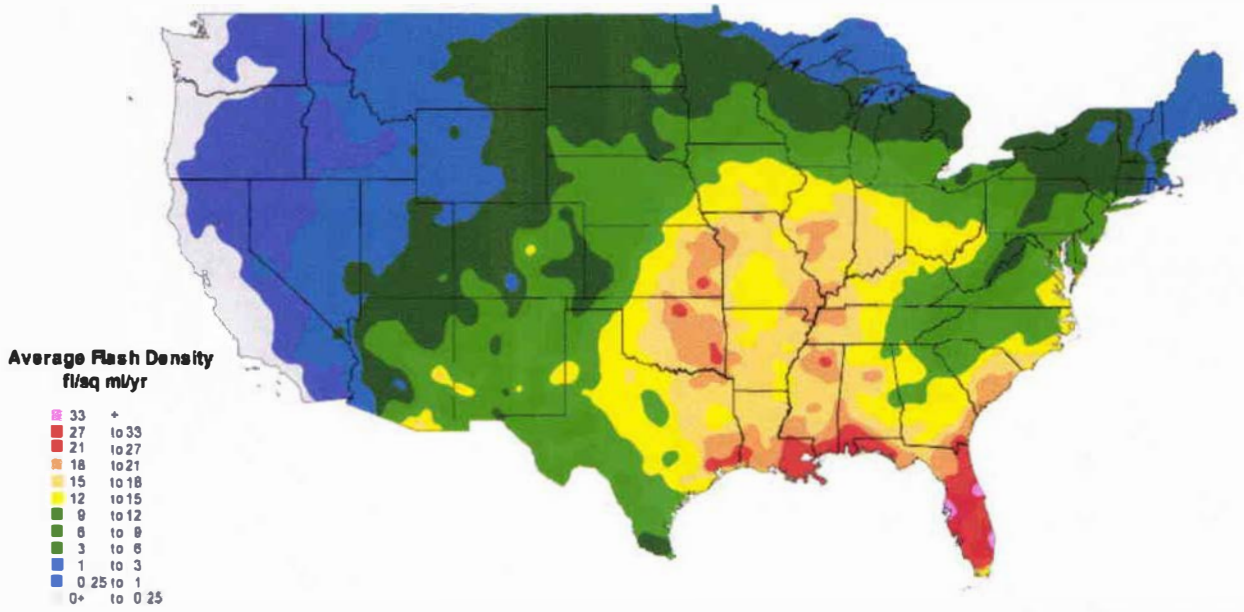


Gulf Power's Service Area & Customer Density Areas



Vaisala's National Lightning Detection Network® (NLDN®)

Cloud-to-Ground Lightning Incidence in the Continental U.S. (1997 - 2012)



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VAISALA

Gulf Power Company
Distribution O&M Budget
2013 to 2017

Category	2013 $ (000's)	2014 $ (000's)	2015 $ (000's)	2016 $ (000's)	2017 $ (000's)
Asset Management	2,837	2,834	2,841	2,849	2,855
Overhead and Underground Line Operation and Maintenance	16,769	16,776	17,100	17,792	17,474
Minor Storms	663	658	663	664	665
Load Dispatch	1,187	1,225	1,235	1,268	1,292
Meters	3,480	3,388	3,452	3,523	3,583
Storm Hardening	367	367	367	368	368
Vegetation Management	5,593	5,948	5,948	5,948	5,948
Engineering & Supervison Overhead	10,079	10,874	11,370	11,815	12,046
Total O&M	**40,975**	**42,070**	**42,976**	**44,227**	**44,231**

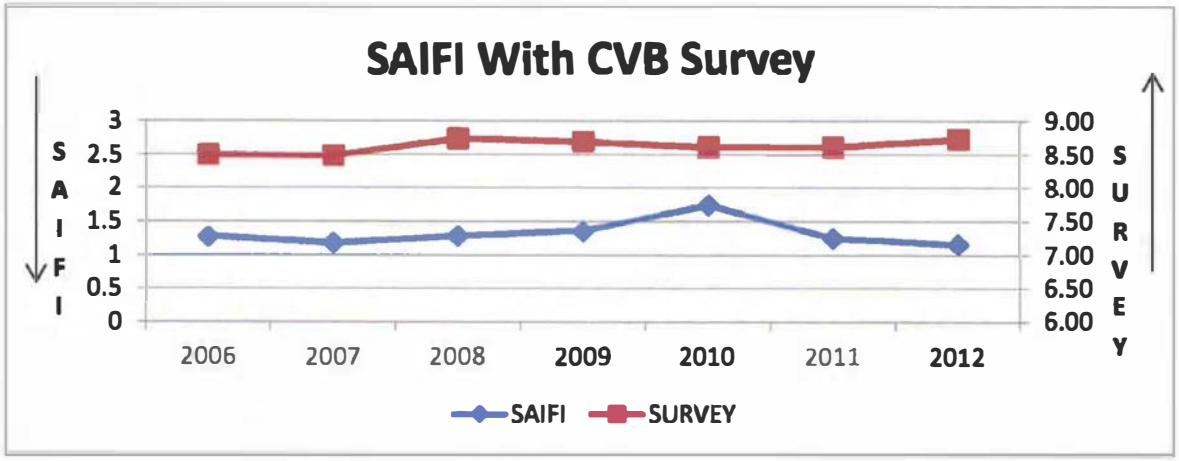
Distribution Benchmark Variance

	(000's)
Test Year Adjusted Benchmark	42,733
Test Year Adjusted Request	42,070
System Benchmark Variance	(663)

Gulf Power Company
2013 - 2014 Distribution/Fleet Capital Additions Budget

Distribution	2013 $ (000's)	2014 $ (000's)
AMI	200	-
Distribution Infrastructure Improvements	18,550	17,337
Storm Hardening	2,801	2,806
Asset Management Improvement Program	4,080	4,082
New Business	11,803	12,040
Distribution Additions/Retirements due to Highway & Joint Use	1,174	1,210
Distribution Transformers	7,532	7,873
Total Capital	**46,140**	**45,348**

General Plant	2013 $ (000's)	2014 $ (000's)
Fleet Investment	3,002	3,340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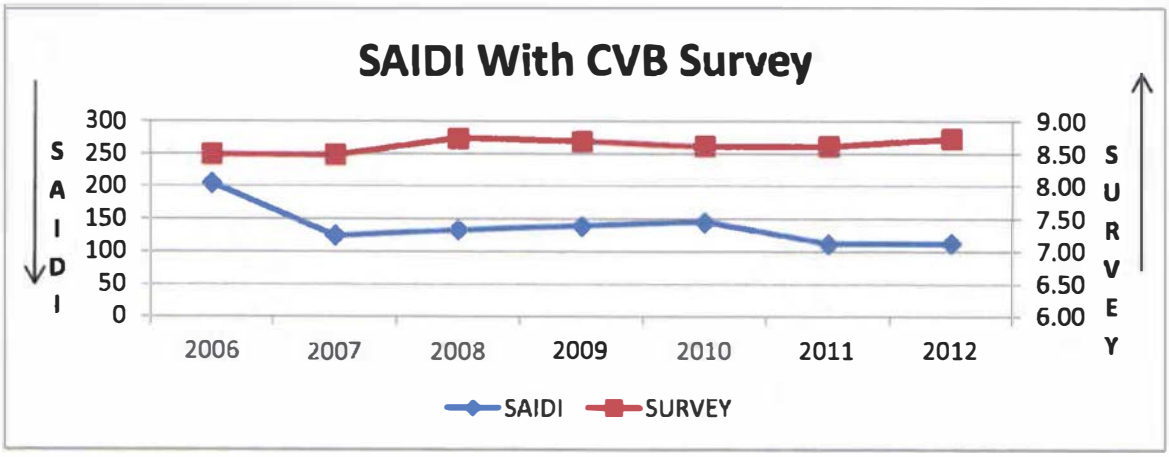
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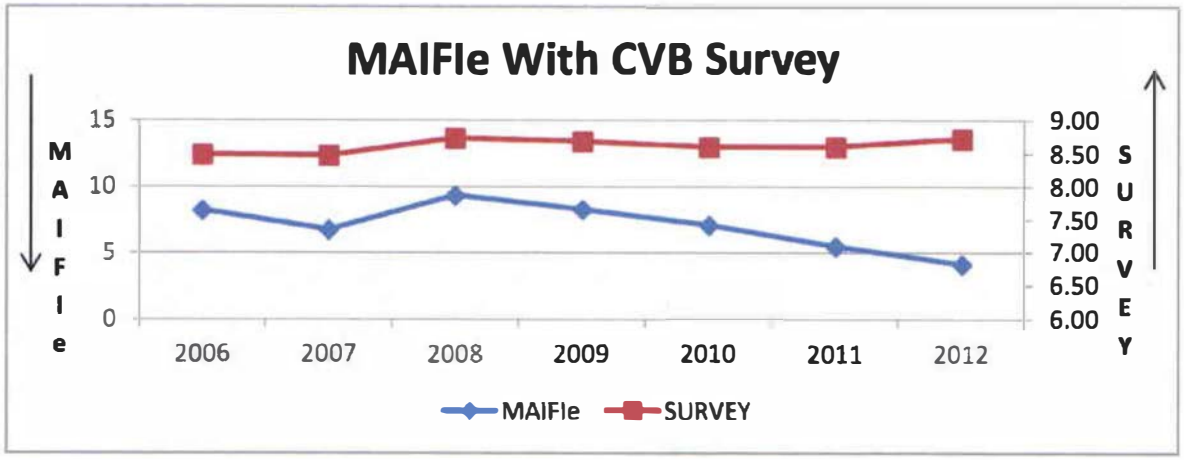
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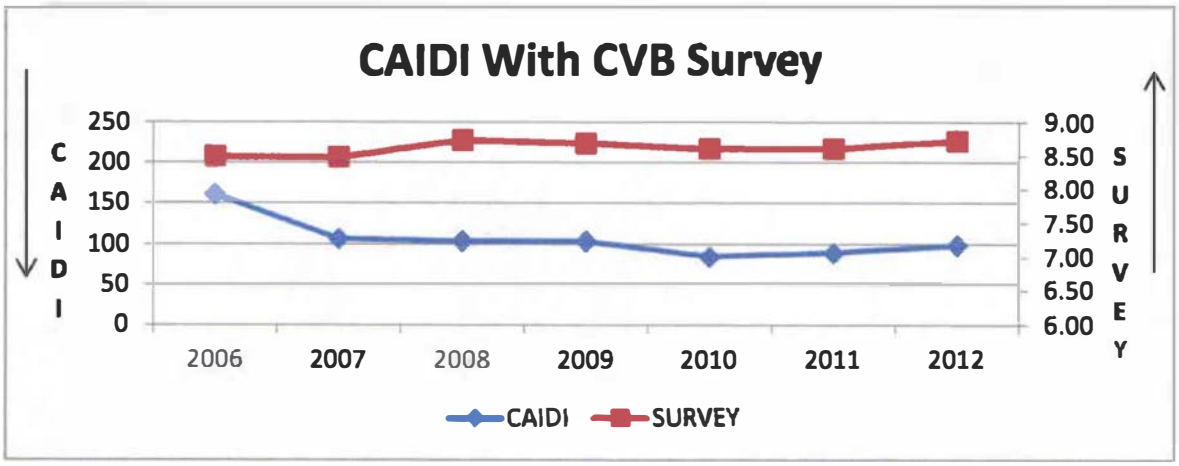
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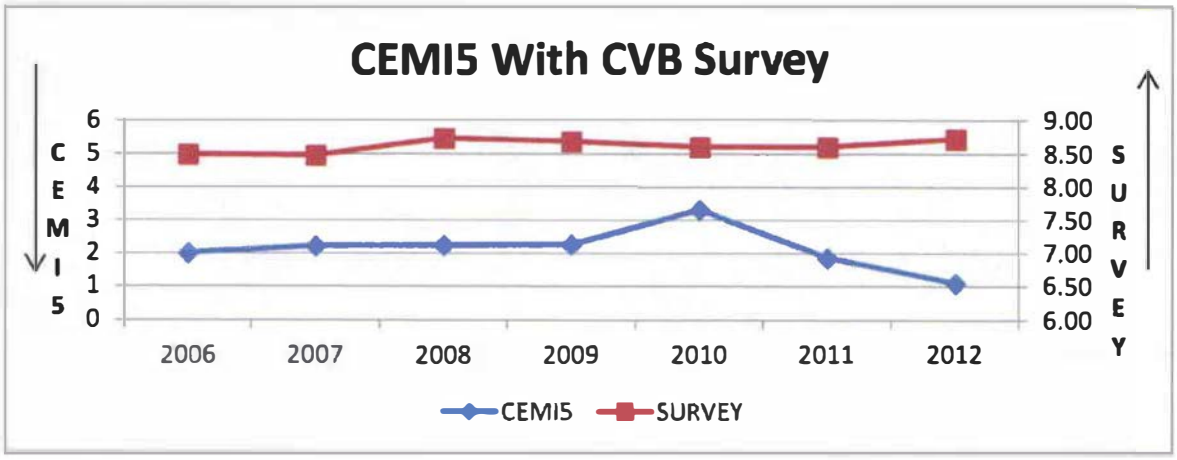
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Responsibility for Minimum Filing Requirements

Schedule	Title
B-16	Nuclear Fuel Balances
B-18	Fuel Inventory by Plant
C-42	Hedging Costs
F-4	NRC Safety Citations
F-5	Forecasting Models
F-8	Assumptions

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130140-EI EXHIBIT 7
PARTY Gulf Power Company (Gulf) Direct
DESCRIPTION Michael L. Burroughs (MLB-1)

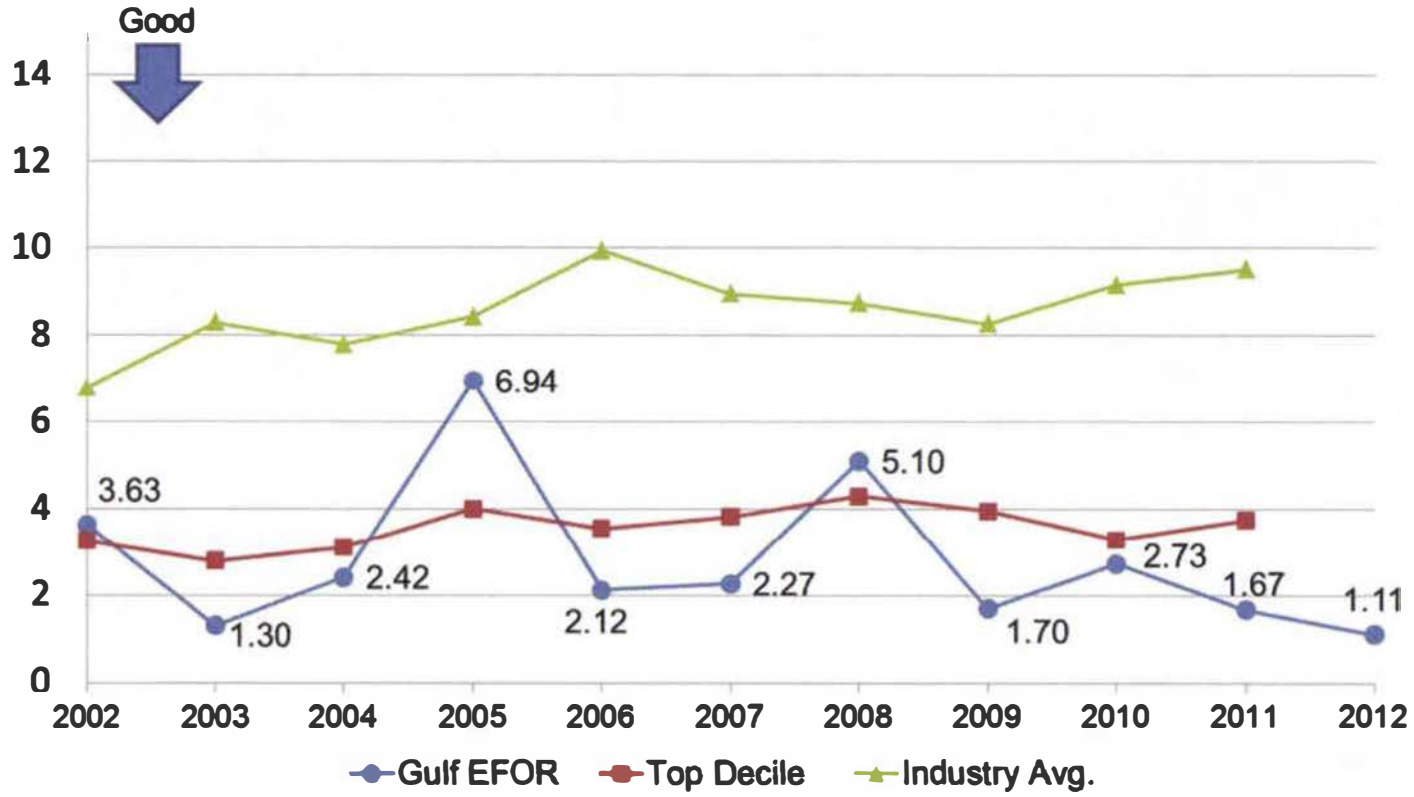
Owned and Operated or Jointly Owned Generating Capacity

Unit Description	Net Generation (MW)	Commercial Operation Date
Crist Unit 4	75	Jul 1959
Crist Unit 5	75	Jun 1961
Crist Unit 6	299	May 1970
Crist Unit 7	475	Aug 1973
Smith Unit 1	162	Jun 1965
Smith Unit 2	195	Jun 1967
Smith Unit 3	556	Apr 2002
Smith Unit A	32	May 1971
Scholz Unit 1	46	Mar 1953
Scholz Unit 2	46	Oct 1953
Pea Ridge Unit 1	4	May 1998
Pea Ridge Unit 2	4	May 1998
Pea Ridge Unit 3	4	May 1998
Perdido Unit 1	1.6	Oct 2010
Perdido Unit 2	1.6	Oct 2010
Daniel Unit 1	255	Sep 1977
Daniel Unit 2	255	Jun 1981

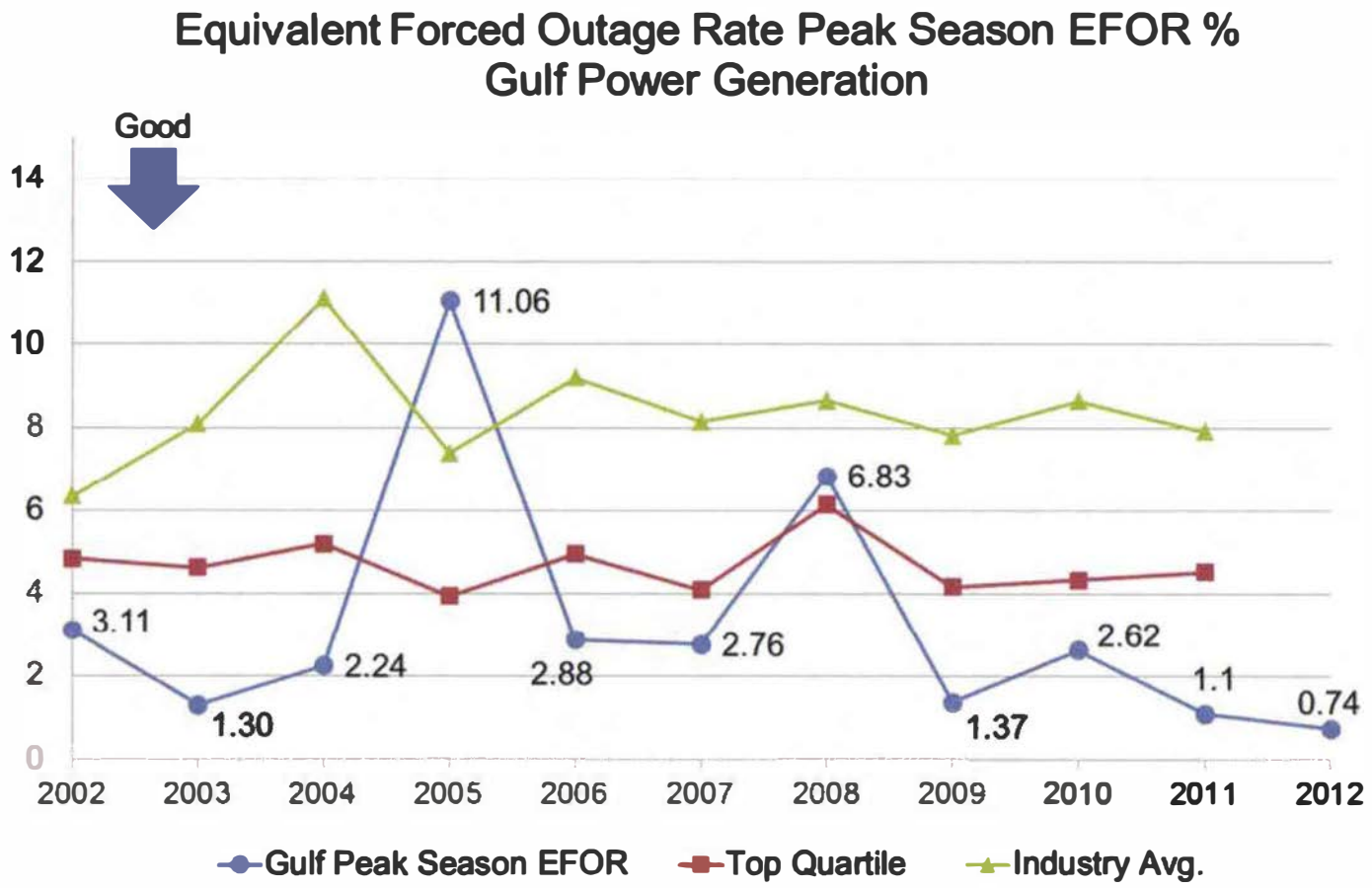
Power Purchase Agreements

Agreement	Technology	Fuel	MW	Start Date	End Date
Bay County	Steam	MSW	11	Jul 2008	Jul 2014
Coral Baconton	CT	Gas/Oil	195	Jun 2009	May 2014
Dahlberg	CT	Gas/Oil	299	Jun 2009	May 2014
Central Ala.	CC	Gas	885	Nov 2009	May 2023

Equivalent Forced Outage Rate Annual EFOR %
Gulf Power Generation



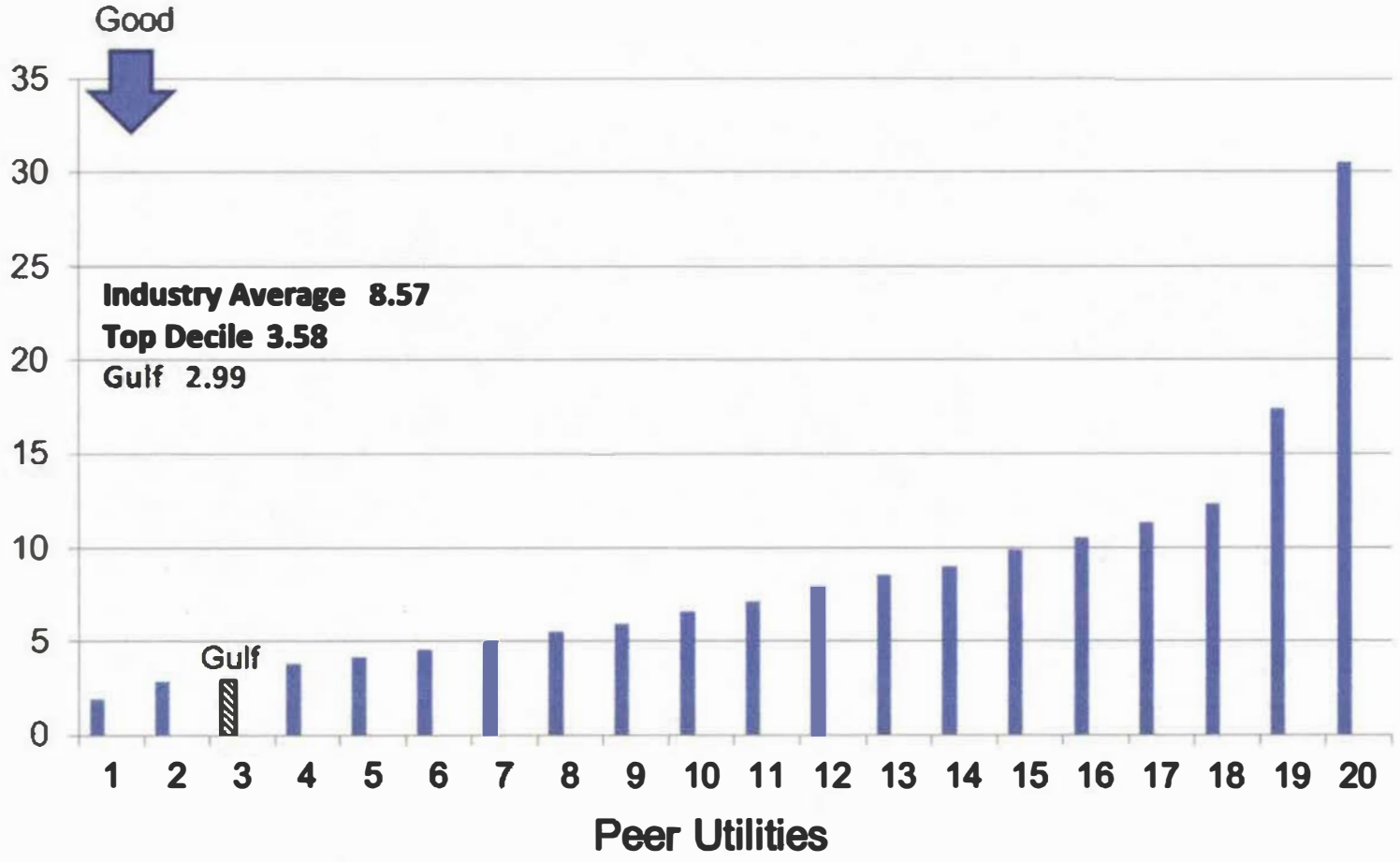
Note: Industry data is not available for 2012



Note: Industry data is not available for 2012

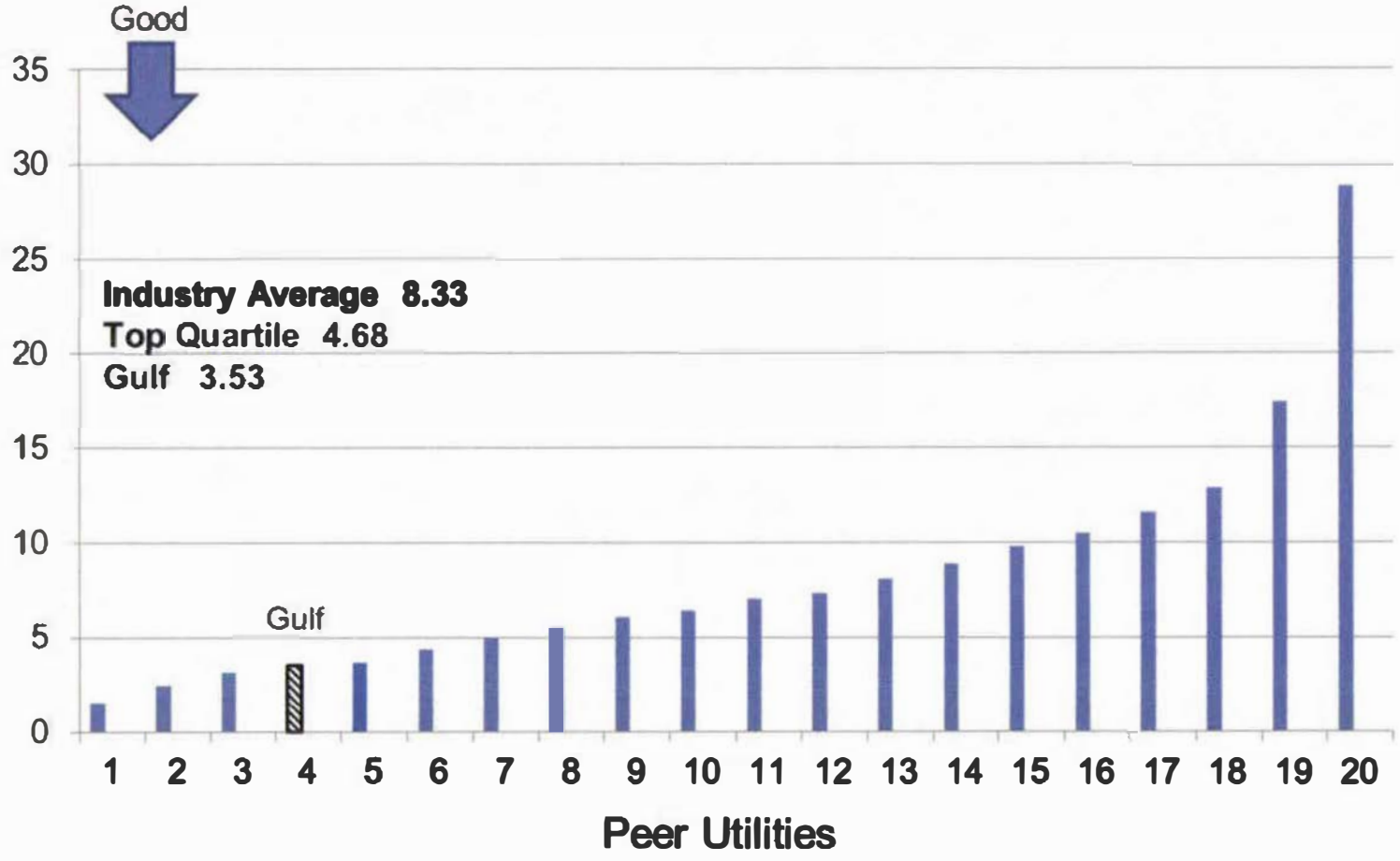
Florida Public Service Commission
Docket No. 130140-EI
GULF POWER COMPANY
Witness: Michael L. Burroughs
Exhibit No. ____ (MLB-1)
Schedule 4
Page 2 of 4

Gulf vs Peer Group
Average Annual EFOR 2002 – 2011
Gulf vs 20 Peer Utilities in Rank Order



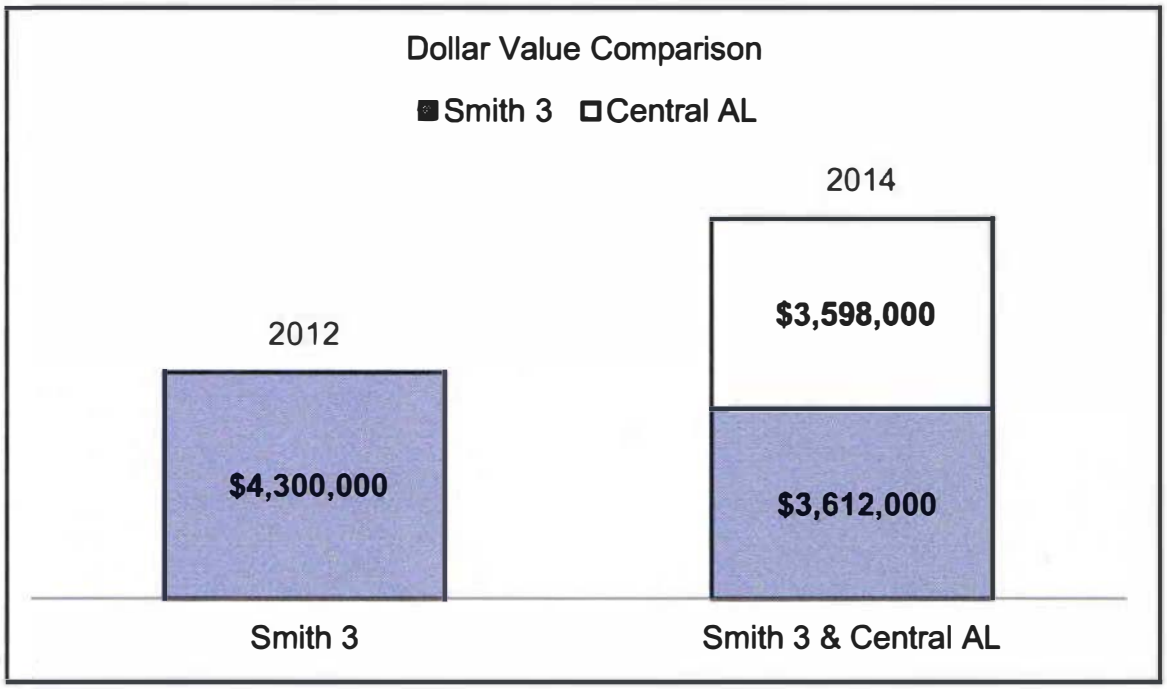
Florida Public Service Commission
Docket No. 130140-EI
GULF POWER COMPANY
Witness: Michael L. Burroughs
Exhibit No. ____ (MLB-1)
Schedule 4
Page 3 of 4

Gulf vs Peer Group
Average Peak Season EFOR 2002 – 2011
Gulf vs 20 Peer Utilities in Rank Order



Florida Public Service Commission
Docket No. 130140-EI
GULF POWER COMPANY
Witness: Michael L. Burroughs
Exhibit No. ____ (MLB-1)
Schedule 4
Page 4 of 4

Gulf Power Company
Natural Gas Inventory Comparison
2012 vs. 2014 Test Year



Gas Value, Volume and Commodity Comparison

	2012			2014		
Facility	Volume Mcf	Price Per Mcf	Total Value	Volume Mcf	Price Per Mcf	Total Value
Smith 3	835,702	$5.15	$4,300,000	811,361	$4.45	$3,612,000
Central AL	0	0	0	808,252	$4.45	$3,598,000
Totals	835,702	$5.15	$4,300,000	1,619,613	$4.45	$7,210,000

Florida Public Service Commission
Docket No. 130140-EI
GULF POWER COMPANY
Witness: Raymond W. Grove
Exhibit No. ___ (RWG-1)
Schedule 1
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Responsibility for Minimum Filing Requirements

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B-12	Production Plant Additions
C-6	Budgeted Versus Actual Operating Revenues and Expenses
C-8	Detail of Changes in Expenses
C-9	Five Year Analysis - Change in Cost
C-34	Statistical Information
C-41	O&M Benchmark Variance By Function
F-5	Forecasting Models
F-8	Assumptions

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130140-EI EXHIBIT 8
PARTY Gulf Power Company (Gulf) Direct
DESCRIPTION Raymond W. Grove (RWG-1)

GULF POWER COMPANY
ENVIRONMENTAL COMPLIANCE PROGRAM UPDATE

For

Clean Air Interstate Rule
National Ambient Air Quality Standards
Mercury and Air Toxics Standards
Clean Air Visibility Rule

A SOUTHERN COMPANY

April 1, 2013

Revised September 24, 2013

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130140-EI EXHIBIT 9
PARTY Gulf Power Company (Gulf) Direct
DESCRIPTION James O. Vick (JOV-1)

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1.0 EXECUTIVE SUMMARY

Since the Clean Air Act Amendments (CAAA) were passed by Congress in 1990, Gulf Power Company (Gulf Power or Gulf) has reviewed and updated its environmental compliance planning as needed on an on-going basis. The goal of this process is to identify reasonable, cost-effective compliance strategies that will minimize the impact on Gulf Power's customers while achieving environmental objectives and assuring compliance with all environmental requirements.

Gulf's original environmental Compliance Plan[1] was filed on March 29, 2007. The original document: (a) addressed the requirements of the Clean Air Interstate Rule (CAIR), Clean Air Mercury Rule (CAMR), and the Clean Air Visibility Rule (CAVR); (b) reviewed the decision process for assuring compliance at Gulf Power; and (c) provided cost estimates for incorporating these requirements at Gulf Power. The document reviewed the specific issues, timing, alternatives, process, and costs necessary for compliance with the new federal rules and the corresponding implementation programs developed by the Florida Department of Environmental Protection (FDEP) and the Mississippi Department of Environmental Quality (MDEQ). Gulf's original Compliance Plan was submitted with the Company's petition for review and approval of the plan and acceptance of its components for cost recovery through the Environmental Cost Recovery Clause (ECRC).

On June 22, 2007, the Office of Public Counsel (OPC), the Florida Industrial Power Users' Group (FIPUG) and Gulf filed a petition for approval of a stipulation regarding the substantive provisions of Gulf's Compliance Plan. That stipulation identified 10 specific components of Gulf's Program that were entering the implementation phase as being reasonable and prudent and set forth a process for review in connection with subsequent components of the Program. On August 14, 2007, the Florida Public Service Commission (Commission or FPSC) voted to approve the stipulation with the proviso that Gulf provide an annual status report regarding cost-effectiveness and prudence of the subsequent phases in its program into which the Company is moving. The Commission's approval of the stipulation is memorialized in Order No. PSC-07-0721-S-EI.

This document is the sixth update of Gulf's original environmental Compliance Plan. Since the Commission's approval of Gulf's Compliance Program in 2007, there have been a number of regulatory and legislative developments. Gulf has addressed in several of its intervening filings, as well as in the annual updates, regulatory updates and changes to schedules of approved projects. There have been several significant court decisions that have had and will have further impacts on Gulf's Compliance Program.

On August 8, 2011, the Environmental Protection Agency (EPA) adopted the Cross State Air Pollution Rule (CSAPR) to replace CAIR effective January 1, 2012. Like the CAIR, the CSAPR was intended to address interstate emissions of SO_2 and NOx that interfere with downwind states' abilities to meet or maintain national ambient air quality standards for ozone and/or particulate matter. In December 2011, the U.S. Court of Appeals for the District of Columbia Circuit stayed the rule and on August 21, 2012, vacated CSAPR in its

1- The title of Gulf's compliance environmental program has been revised since the original filing in March of 2007. NAAQS and MATS were added to the title when the rules were adopted. Likewise, CAMR was removed from the title when the CAMR rule was vacated.

entirety and directed the EPA to continue to administer CAIR pending the EPA's development of a valid replacement rule. The states of Florida and Mississippi had already completed plans to implement CAIR, and emissions reductions were being accomplished by the installation and operation of emission controls at the Company's coal-fired facilities and/or by the purchase of emission allowances.

The Clean Air Visibility Rule was finalized in July 2005 with a goal of restoring natural visibility conditions in certain areas (primarily national parks and wilderness areas) by 2064. In 2005, the EPA determined that compliance with CAIR satisfies Best Available Retrofit Technology (BART) obligations under CAVR, but on June 7, 2012, the EPA issued a final rule replacing CAIR with CSAPR as an alternative means of satisfying BART obligations. The vacatur of CSAPR creates additional uncertainty with respect to whether additional controls may be required for CAVR and BART compliance.

In February 2008, the U.S. Court of Appeals for the District of Columbia Circuit (D.C. Circuit) issued an opinion vacating the EPA's CAMR. In a separate proceeding in the U.S. District Court for the District of Columbia, the Court, under a consent decree, required the EPA to issue a proposed Electric Generating Unit (EGU) Maximum Achievable Control Technology (MACT) rule by March 16, 2011, and a final rule by November 16, 2011. The MACT rule, renamed the Mercury and Air Toxics Standards (MATS), was published in the federal register on February 16, 2012. The MATS rule imposes stringent emissions limits for mercury, acid gases and particulate matter on coal and oil-fired electric utility generating units. Compliance for existing sources is required by April 16, 2015, three years after the effective date of the rule.

As discussed in previous compliance strategy updates, compliance with the MATS rule is likely to require substantial capital expenditures and compliance costs. These costs may arise from unit retirements, installation of additional emission controls, changing fuel sources for certain existing units, and/or upgrades to the transmission system. The MATS rule also requires installation of additional continuous emission monitors and/or additional emissions testing.

Gulf has recently finalized its MATS compliance strategy for Plant Crist and Plant Daniel. Gulf has determined that it is not economical to add the environmental controls at Plant Scholz necessary to comply with MATS and that coal-fired generation will cease at Plant Scholz on April 1, 2015. Gulf has not finalized its MATS compliance strategy for Plant Smith; however, Gulf has determined that the installation of transmission upgrades should be part of any of the potentially viable MATS compliance strategies for Plant Smith. Once the Company determines the most cost-effective compliance options for Plant Smith, Gulf will submit revisions to the environmental Compliance Program for the Commission's review.

This document addresses Gulf's ongoing compliance projects as well as new MATS compliance projects selected for Plant Crist, Plant Daniel, and Plant Smith. Gulf's Compliance Program has been updated to include the Plant Daniel Bromine and Activated Carbon Injection (ACI) Project, the Plant Crist Transmission Upgrades Project, and the Plant

Smith Transmission Upgrades Project that will be required for compliance with the MATS rule. Gulf Power is requesting approval of inclusion of these projects in the Company's Compliance Program at this time. Gulf Power's ultimate compliance program will be impacted by factors such as: final requirements of new or revised environmental regulations; the cost and availability of emissions allowances; performance of emission control equipment; and changes to the Company's fuel mix. Based on these factors, future environmental compliance costs will continue to be incurred, and projections will be revised. The timing of the requirements and costs incurred will be a function of the compliance options selected, new generating resources, fuel sources and prices, fuel sulfur content, transmission upgrades, energy demand, and other variables.

Detailed capital and O&M costs for Gulf's Compliance Program for CAIR, MATS, and CAVR are provided in Section 3 of this document. As noted in the Commission's approval of Gulf's original environmental Compliance Program, the program would likely evolve over time. For example, the Plant Smith Units 1 and 2 scrubber and the Plant Smith baghouse project, have been removed from Gulf's Compliance Program. The Plant Smith scrubber and baghouse projects were originally included in Gulf's Compliance Program for future consideration; however, it has been determined that the projects are no longer viable compliance options. Environmental compliance strategies for Plant Smith are being evaluated in response to finalization of the MATS rule, vacatur of the CSAPR, CAVR, and anticipation of future land and water regulations.

In addition to the air rules mentioned above that are aimed at reductions of NOx, SO_2, mercury, acid gases and particulate matter, the EPA is regulating greenhouse gas (GHG) emissions under the Clean Air Act. The EPA has proposed GHG performance standards for new electric generating units and is planning to develop federal guidelines for states to establish greenhouse gas performance standards for existing units.

During the 2013-2014 timeframe, the EPA is expected to issue new land and water regulations that will affect the storage and handling of coal combustion byproducts (CCB), intake structure requirements, and effluent guidelines. Once finalized, these rules could further impact Gulf's Compliance Program. All of this uncertainty reinforces the need for a flexible, robust compliance plan. Accordingly, as Gulf finalizes its strategy for complying with the MATS regulations, as decision dates for equipment purchases approach, and as regulatory and economic drivers become better defined, the analysis will be updated as needed to enable the selection of the most reasonable and cost-effective compliance alternatives while maintaining future flexibility in the plan.

2.0 REGULATORY AND LEGISLATIVE UPDATE

This section provides a regulatory and legislative update and review of the CAIR and its vacated replacement rule, the Cross State Air Pollution Rule (CSAPR), the National Ambient Air Quality Standards (NAAQS), the CAVR, as well as the vacated CAMR and its replacement rule the Mercury and Air Toxics Standards (MATS).

2.1 CLEAN AIR INTERSTATE RULE / CROSS STATE AIR POLLUTION RULE

In March 2005, the EPA published the final CAIR, a rule that addresses transport of SO_2 and NOx emissions that contribute to non-attainment of the ozone and fine particulate matter NAAQS in the eastern United States. This cap and trade rule addresses power plant SO_2 and NOx emissions that were found to contribute to non-attainment of the 8-hour ozone and fine particulate matter standards in downwind states. Twenty-eight eastern states, including Florida and Mississippi, are subject to the requirements of the rule. The rule calls for additional reductions of NOx and SO_2 to be achieved in two phases, 2009/2010 and 2015, as shown in Table 2.1-1.

Table 2.1-1

CAIR Emission Reduction Requirements

Emissions	Phase I reduction from acid rain allocations	Phase II reduction from current allocations
SO_2	50% (2010)	66% (2015)
NOx	50% (2009)	65% (2015)

In 2008, the U.S. Court of Appeals for the District of Columbia Circuit issued decisions invalidating certain aspects of the CAIR, but left CAIR compliance requirements in place while the EPA developed a new rule. In August 2011, the EPA adopted the CSAPR to replace CAIR effective January 1, 2012. Like the CAIR, the CSAPR was intended to address interstate emissions of SO_2 and NO_x that interfere with downwind states' abilities to meet or maintain national ambient air quality standards for ozone and/or particulate matter. However, in December 2011, the U.S. Court of Appeals for the District of Columbia Circuit stayed the rule and on August 21, 2012, vacated CSAPR in its entirety and directed the EPA to continue to administer CAIR pending the EPA's development of a valid replacement. On January 24, 2013, the U.S. Court of Appeals for the District of Columbia Circuit denied requests by the EPA and other parties for rehearing.

The states of Florida and Mississippi have completed plans to implement CAIR, and emissions reductions are being accomplished by the installation and operation of emission controls at the Company's coal-fired facilities and/or by the purchase of emission allowances. Decisions regarding Gulf's CAIR compliance strategy were made jointly with the CAVR and CAMR compliance plans due to co-benefits of proposed controls.

2.2 NATIONAL AMBIENT AIR QUALITY STANDARDS

Final revisions to the National Ambient Air Quality Standard (NAAQS) for SO_2, including establishment of a new one-hour standard, became effective during August 2010. The EPA plans to issue area designations under this new standard in June 2013. This may result in some of the Company's service area ultimately being designated as nonattainment. Implementation of the revised SO_2 standard could require additional reductions of SO_2 emissions and increased compliance and operational costs.

The EPA regulates ground level ozone through implementation of an eight-hour ozone NAAQS. In March 2008, the EPA adopted a more stringent eight-hour ozone standard, which it began to implement in September 2011. On May 21, 2012, the EPA published a final determination of nonattainment areas based on the 2008 eight-hour ozone air quality standards. No areas within the Company's service area were determined to be in nonattainment of this standard. The EPA will continue reviewing the ozone NAAQS under the normal five-year review cycle with a new revision expected in 2014.

The EPA regulates fine particulate matter concentrations on an annual and 24-hour average basis. All areas within the Company's service area have achieved attainment with the 1997 and 2006 particulate matter NAAQS. On January 15, 2013, the EPA published a final rule that increases the stringency of the annual fine particulate matter standard. The new standard could result in the designation of new nonattainment areas within the Company's service area.

Revisions to the NAAQS for nitrogen dioxide (NO_2), which established a new one-hour ozone standard, became effective in April 2010. The EPA signed a final rule with area designations for the new NO_2 standard in January 2012, designating the entire country as "unclassifiable/attainment," with no nonattainment areas designated. While this standard is not focused on the electric utility sector, the new NO_2 standard could result in additional compliance and operational costs for units that require new source permitting.

2.3 CLEAN AIR VISIBILITY RULE

The Clean Air Visibility Rule (formerly called the Regional Haze Rule) was finalized in 2005, with a goal of restoring natural visibility conditions in certain areas (primarily national parks and wilderness areas) by 2064. The rule involves the application of Best Available Retrofit Technology (BART) to certain sources built between 1962 and 1977 and any additional emissions reductions necessary for each designated area to achieve reasonable progress toward the natural conditions goal by 2018 and for each 10-year planning period

thereafter. In 2005, the EPA determined that compliance with the CAIR satisfies BART obligations under CAVR, but, on June 7, 2012, the EPA issued a final rule replacing CAIR with CSAPR as an alternative means of satisfying BART obligations. The vacatur of CSAPR creates additional uncertainty with respect to whether additional controls may be required for CAVR and BART compliance.

In the face of this uncertainty the states have proceeded with various activities. Florida submitted a revised State Implementation Plan (SIP) on September 17, 2012 that abandoned reliance on CAIR or CSAPR and proposed a series of EGU BART limits in August and December 2012 which included BART limits for the coal fired units at Plant Smith and no further controls for Plant Crist. The EPA completed a review of the Florida SIP and proposed approval on December 14, 2012. The EPA must finalize approval or disapproval of the Florida SIP by June 28, 2013. Similar to Florida, the State of Mississippi requested source-specific BART analyses by December 15, 2012. A report for Plant Daniel was submitted in December that demonstrated that the plant already meets "top level control" relative to BART. Following submittal of a revised Mississippi SIP, the EPA will have until the summer of 2014 to finalize an approval or disapproval. Until these issues are resolved, it remains uncertain what additional controls will ultimately be required at Plant Smith, Plant Crist and Plant Daniel for CAVR and BART compliance.

2.4 CLEAN AIR MERCURY RULE / MERCURY AND AIR TOXICS STANDARDS

In March 2005, the EPA published the final Clean Air Mercury Rule (CAMR), a cap and trade program for the reduction of mercury emissions from coal-fired power plants. The rule set caps on mercury emissions to be implemented in two phases, 2010 and 2018, and provided for an emission allowance trading market. The final CAMR was challenged in the D.C. Circuit and in February 2008, the court issued an opinion vacating the CAMR. The vacatur became effective with the issuance of the court's mandate on March 14, 2008, nullifying CAMR mercury emission control obligations and monitoring requirements. In a separate proceeding in the U.S. District Court for the District of Columbia, the Court, under a consent decree, required the EPA to issue a final MACT rule by November 16, 2011.

On February 16, 2012, the EPA published the final Mercury Air Toxics Standards (MATS) rule, which imposes stringent emissions limits for acid gases, mercury, and particulate matter (surrogate for non-mercury metals) on coal- and oil-fired electric utility steam generating units. Compliance for existing sources is required by April 16, 2015 three years after the effective date of the final rule, unless a one-year extension is granted by the state or local air permitting agency. Sources needing a fifth year to comply may seek an Administrative Order under Section 113(a) of the Clean Air Act. According to the EPA, an Administrative Order would be limited to units that are required to run for reliability purposes.

Numerous petitions for administrative reconsideration of the MATS rule were filed with the EPA. On November 30, 2012, the EPA proposed a reconsideration of certain new source and startup/shutdown issues. The EPA plans to complete its reconsideration rulemaking by April

2013. Challenges to the final rule have also been filed in the U.S. Court of Appeals for the District of Columbia by numerous states, environmental organizations, industry groups, and others.

3.0 GULF'S COMPLIANCE PROGRAM

3.1 GULF POWER'S ELECTRIC GENERATING SYSTEM

Gulf Power owns and operates three fossil–fueled generating facilities in Northwest Florida (Plants Crist, Smith and Scholz). Gulf also owns a 50 percent undivided ownership interest in Units 1 and Unit 2 at Mississippi Power Company's Plant Daniel. This fleet of generating units consists of ten fossil steam units, one combined cycle (CC) unit, and one combustion turbine (CT). The nameplate generating capacity of Gulf's generating fleet affected by CAIR/CSAPR, NAAQS, MATS, and/or CAVR is 2,783 megawatts (MW).

This document is the sixth update of Gulf's original environmental Compliance Plan filed on March 29, 2007. The original document: (a) addressed the requirements of the Clean Air Interstate Rule (CAIR), Clean Air Mercury Rule (CAMR), and the Clean Air Visibility Rule (CAVR); (b) reviewed the decision process for assuring compliance at Gulf Power; and (c) provided cost estimates for incorporating these requirements at Gulf Power. The document reviewed the specific issues, timing, alternatives, process, and costs necessary for compliance with the new federal rules and the corresponding implementation programs developed by the Florida Department of Environmental Protection (FDEP) and the Mississippi Department of Environmental Quality (MDEQ).

On June 22, 2007, the Office of Public Counsel (OPC), the Florida Industrial Power Users' Group (FIPUG) and Gulf filed a petition for approval of a stipulation regarding the substantive provisions of Gulf's CAIR/CAMR/CAVR Compliance Plan. On August 14, 2007, the Commission voted to approve the stipulation with the proviso that Gulf provide an annual status report regarding cost-effectiveness and prudence of the phases in its Plan into which the Company is moving. That stipulation identified the following 10 specific components of Gulf's plan as being reasonable and prudent for implementation and set forth a process for review in connection with the three remaining components of the plan.

- Crist Units 4 through 7 Scrubber
- Crist Unit 6 Selective Catalytic Reduction (SCR) Project
- Crist Units 4 through 7 CAIR and Mercury Monitor
- Daniel Units 1 and 2 Scrubbers
- Daniel Units 1 and 2 SNCRs and Low NOx Burners
- Daniel Units 1 and 2 CAIR and Mercury Monitors
- Smith Units 1 and 2 Selective Non-Catalytic Reduction (SNCR) Projects
- Smith Units 1 and 2 CAIR and Mercury Monitors
- Scholz Units 1 and 2 Mercury Monitors
- Market Purchase of Additional Emission Allowances

The remaining components of Gulf's proposed Compliance Plan specifically identified in the initial 2007 filing were still in the planning phase at that time, with possible implementation not expected to occur until after 2011. The specifically identified components included the

Plant Daniel Unit 1 and Unit 2 SCRs, the Plant Smith Unit 1 and Unit 2 scrubber, and the Plant Smith Unit 2 baghouse. The parties stated in their stipulation that since Gulf had not yet made its decision whether to implement these additional components, there was no agreement at that time regarding their reasonableness or prudence. The stipulation provides that once Gulf makes a decision to proceed with implementation of additional components, Gulf would make a supplementary filing in the ECRC docket identifying the timing of planned implementation and providing updated estimates prior to incorporating them in the normal projection or true-up filings under the ECRC.

On April 1, 2010, Gulf filed its second supplemental petition to update its Compliance Program to include the next implementation phase of the Program, the Plant Daniel Unit 1 and Unit 2 SCRs. The Plant Daniel SCR projects were approved in PSC Order No. PSC-10-0683-FOF-EI dated November 15, 2010. The Plant Smith Units 1 and 2 scrubber and the Plant Smith baghouse project, have since been removed from Gulf's Compliance Program. The Plant Smith scrubber and baghouse projects were originally included in Gulf's Compliance Program for future consideration; however, it has been determined that the projects are no longer viable compliance options

This filing will update Gulf's Compliance Program to include the Plant Daniel Bromine and ACI Project, the Plant Crist Transmission Upgrades Project, and the Plant Smith Transmission Upgrades Project that will be required for compliance with the MATS rule. Gulf Power is requesting approval of inclusion of these projects in the Company's Compliance Program.

A summary of the updated Compliance Program capital projects and associated expenditures through 2022 is provided in Table 3.1-1. The projected plant O&M expenses associated with the capital projects are included in Table 3.1-2. The cost information is provided by plant and by project.

Table 3.1-1
Compliance Program Capital Expenditures
$ in Thousands

	Prior Years**	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	Total
By Plant												
Plant Crist												
Mercury Monitoring												
Unit 6 SCR	191,424											
Units 4-7 Scrubber	587,048											587,048
MATS Transmission Upgrades*	23	1,028	37,382	16,703	2,565	13,253	5,403					76,357
Plant Scholz												
Mercury Monitoring	644											644
Plant Smith												
Unit 1 SNCR	8,363											8,363
Unit 2 SNCR	2,905											2,905
Mercury Monitoring	1,433											1,433
CAIR Parametric Monitor	230											
MATS Transmission Upgrades*	1,765	26,945	41,900	6,370								76,980
Plant Daniel												
Mercury Monitoring												
Unit 1 SCR												
Unit 2 SCR												
Units 1 & 2 Scrubber	69,087											
Unit 1 Low NOx Burners	3,187											3,187
Unit 2 Low NOx Burners	3,586											3,586
Unit 1 & 2 Bromine & Activated Carbon Injection*												
By Project												
Mercury Monitoring	2,077											
SCRs	191,424											
Scrubbers	656,135											
SNCRs	11,268											11,268
CAIR Parametric Monitor	230											
Low Nox Burners	6,773											6,773
Unit 1 & 2 Activated Carbon & Bromine Injection												
MATS Transmission Upgrades	1,788	27,973	79,282	23,073	2,565	13,253	5,403					153,337
Annual Total	**869,695**	**142,631**	**188,670**	**99,296**	**95,994**	**145,036**	**60,975**	**4,067**	**667**	**333**	**667**	**1,608,031**

***Items Gulf seeks to include in the Compliance Program. All other items previously approved.**

****2006-2012 expenditures**

Expenditures presented for Plant Daniel represent Gulf's ownership portion.

Allowance cost projections are not included in Table 3.1-1

Table 3.1-2
Compliance Program Plant O&M Expenses
$ in Thousands

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	Total
By Plant											
Plant Crist											
Mercury Monitoring	[redacted]										
Unit 6 SCR											
Units 4-7 Scrubber											
Plant Scholz											
Mercury Monitoring											
Plant Smith											
Unit 1 & 2 SNCR											
Mercury Monitoring											
Plant Daniel											
Mercury Monitoring											
Unit 1 SCR											
Unit 2 SCR											
Units 1&2 Scrubber											
Unit 1 & 2 Bromine & Activated Carbon Injection*											
By Project											
Mercury Monitoring											
SCRs											
Scrubbers											
SNCRs											
Activated Carbon & Bromine Injection*											
Annual Total	15,578	16,783	23,494	33,892	34,298	35,620	38,569	39,557	40,870	41,918	320,579

***Items Gulf seeks to include in the Compliance Program. All other items previously approved.**
Expenses presented for Plant Daniel represent Gulf's ownership portion.
Allowance cost projections are not included in Table 3.1-2

Docket No. 130140-EI
Environmental Compliance Program Update
Revised September 24, 2013
Exhibit JOV-1, Page 14 of 34

3.2 GULF'S EVALUATION OF MATS COMPLIANCE OPTIONS

For Gulf Power's plants Crist and Daniel, compliance options to address the impact of the MATS requirements were proposed and the cost of those options were evaluated. The Company evaluated the alternatives for each facility to determine the most reasonable, reliable, and cost effective plan. Gulf has not finalized its MATS compliance strategy for Plant Smith; however, a similar evaluation was conducted to determine the first part of Plant Smith's MATS strategy. Section 3.3 discusses the MATS evaluation on a plant-by-plant basis. Even though applicable options are unit specific, the economic evaluation for each option is structured similarly.

Generally, the economic evaluation includes unit commitment and energy value modeling and cost implications. A comparison analysis for each compliance option is conducted to help determine the most economical option by capturing the applicable fixed costs and relative changes to system production costs. These fixed costs include:

- Firm natural gas transportation costs, if any
- Revenue requirements for incremental capital additions for environmental controls
- Revenue requirements for incremental transmission capital additions for environmental compliance

System production cost impacts are estimated using the Southern electric system's marginal replacement costs for each viable compliance alternative. Marginal replacement costs are generated with the Pro-Sym® model. The marginal replacement costs are then used in the Southern Company GenVal model to dispatch the existing unit under each option, considering its marginal fuel cost, emission allowance price, and variable operation and maintenance costs (including any additional environmental variable operating costs). This model also considers any forced commitment and dispatch needed to maintain transmission system reliability (must-run requirements). The energy benefits of each option (marginal replacement costs minus variable operating costs) are compared to determine the commitment and energy value to the Southern electric system for each compliance option. Under unconstrained unit operation, the existing unit is allowed to commit and dispatch in the most economic manner to generate optimized system production costs. When a unit is forced to commit and dispatch to meet transmission reliability requirements, the system production costs are sub-optimal. The delta between these sub-optimal system production costs and the optimized system production costs are the must-run production costs associated with the transmission reliability requirement or the must-run production cost savings associated with removing the transmission reliability requirement.

The system production cost impacts are evaluated across a range of integrated scenarios in order to capture variations in the operating environments that would affect the relative costs of the options. These scenarios were developed around uncertainty in fuel prices and CO_2 policy. Fuel prices (primarily natural gas driven) included low, moderate, and high scenarios, and CO_2 penalties range from $0 to $20 per metric tonne (escalating above inflation).

3.3 PLANT-BY-PLANT COMPLIANCE PROGRAM

3.3.1 PLANT CRIST

Plant Crist is a four-unit, coal-fired electric generating facility located just north of Pensacola, Florida. Three older natural gas/oil-fired units at the site have been retired. Units 4 and 5 each have a nameplate rating of 93.75 MW and Units 6 and 7 have nameplate ratings of 370 MW and 578 MW, respectively. All four units were affected under the Acid Rain Program, and the plant has primarily operated on low-sulfur coals since the 1990s to lower SO_2 emissions. All four units are equipped with low-NOx burner systems. Plant Crist Units 4 and 5 have SNCR systems, while Crist Units 6 and 7 are equipped with SCR systems for NOx control.

The Plant Crist Unit 7 SCR became operational in 2005, significantly reducing emissions of NOx from the plant. This project was the result of an agreement between Gulf and the FDEP. The agreement also called for additional NOx reductions on Plant Crist Units 4 through 6 up to and including an SCR for Unit 6. The Plant Crist Unit 6 SCR was placed in service during 2012.

The Plant Crist Units 4 through 7 flue gas desulfurization (FGD) scrubber became operational in December 2009 and is designed to reduce SO_2 emissions by approximately 95%. With these reductions, Gulf Power will be able to reasonably manage compliance with its SO_2 allowance bank for the acid rain program and CAIR. Mercury emissions are also being reduced through the co-benefits of the scrubber and SCRs. The Plant Scholz mercury monitor has been relocated to Plant Crist in order to further analyze Plant Crist mercury emissions.

Plant Crist MATS Requirements

The MATS requirements apply to the four coal-fired units at Plant Crist. A review of Plant Crist emissions data was performed using recent annual particulate tests and data from the scrubber stack's SO_2 and mercury CEMS. This historical data indicates that during normal operation with the scrubber and SCRs in-service, Plant Crist should meet MATS requirements without any additional emissions controls, such as a baghouse. However, the MATS rule does limit the ability of the units to operate in the event of a scrubber malfunction or outage for any meaningful period of time without additional environmental controls. Without the ability to operate the Plant Crist units during a scrubber malfunction or outage, a reliability risk is introduced to the operation of the transmission system as it stands today.

Currently, when the scrubber is out of service due to malfunction or outage, the scrubber is bypassed and the emissions exhaust through the appropriate bypass stack. This mode of operation is termed "scrubber maintenance" or "scrubber bypass" mode. With the scrubber bypassed, the SO_2 and mercury emissions emitted from the bypass stacks would not meet

their respective MATS limits, and Plant Crist would be unable to operate until the scrubber is back in service. This MATS limitation is an important consideration in evaluating MATS compliance for Plant Crist because generation from this plant meets reliability requirements for Gulf's transmission system.

[redacted]

Studies were performed to identify the key transmission projects that would be necessary to alleviate this transmission risk in the event of a scrubber malfunction or outage. As explained in the following section, the best option for MATS compliance at Plant Crist for Gulf's customers is to proceed with the identified transmission projects in order to allow Plant Crist to commit and dispatch in the most economic manner, while avoiding the installation of additional environmental controls.

Plant Crist MATS Options

Gulf evaluated four options to address the impact of the MATS requirements on Plant Crist, as illustrated in Figure 3.3-1:

Option 1-[redacted] MW Natural Gas:
Supply Plant Crist with enough natural gas to generate at least [redacted] MW to meet the current transmission reliability requirements. This would require a new natural gas pipeline lateral.

Option 2-[redacted] MW Natural Gas/[redacted] MW Coal with ACI and DSI Controls:
Use the existing natural gas pipeline to provide [redacted] MW of generation with the remaining [redacted] MW of generation needed for current transmission reliability requirements provided by coal. This would not require a new gas lateral, but would require ACI and dry sorbent injection (DSI) controls for the scrubber bypass and would require the use of low sulfur and low chloride coal for long bypasses. This option would require an inventory of the low sulfur/low chloride coal.

Option 3-[redacted] MW Natural Gas and Transmission Upgrades:
Use the existing natural gas pipeline capacity to provide [redacted] MW of generation and implement certain transmission improvements to reduce the Plant Crist transmission reliability requirement from [redacted] MW to [redacted] MW.

Option 4- Transmission Upgrades Only:
Construct the transmission improvements necessary to remove all significant

transmission reliability (must-run) requirements for Plant Crist, allowing it to commit and dispatch economically.

Plant Crist Scrubber Bypass MATS Analysis

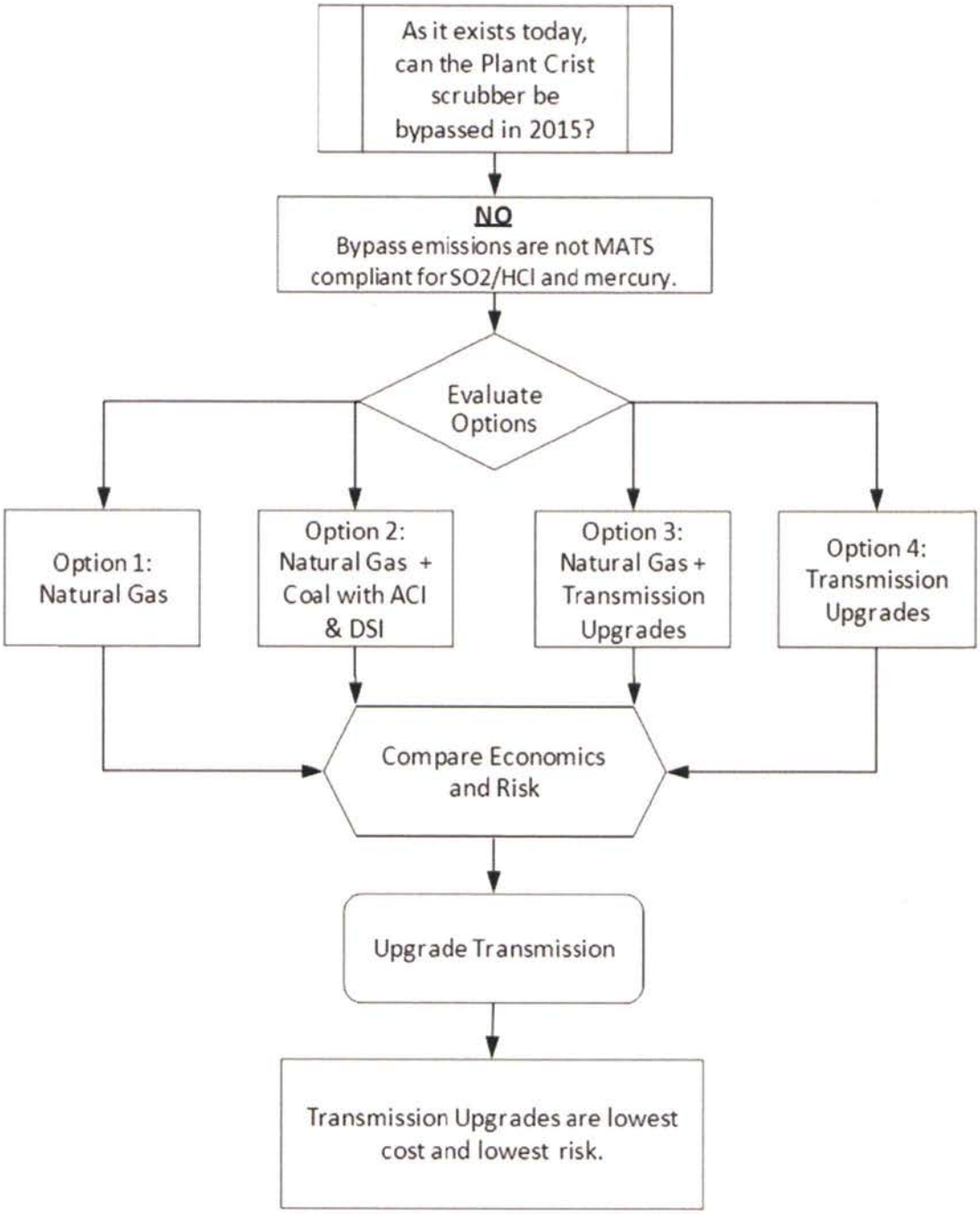


Figure 3.3-1 Plant Crist MATS Scrubber Bypass Analysis

Plant Crist MATS Analysis

For each Plant Crist MATS option, the NPV (Net Present Value) of estimated revenue requirements was calculated for transmission upgrades, fuel, must-run production costs, and emission control retrofits. The transmission NPV for Options 1 and 2 were the NPV of transmission projects that were projected to be needed primarily in the 2020 to 2025 timeframe even without the MATS rule. These NPVs were considered to be a base transmission cost. Transmission NPVs for Options 3 and 4 reflect higher costs of $[redacted]M and $[redacted]M, respectively, due to acceleration of many of these base transmission projects that Gulf must now move forward with due to MATS under these compliance options.

The fuel NPV included a gas pipeline cost for Option 1 and gas firm transportation cost for Options 1, 2, and 3. The must-run production cost NPV is the increased production cost of requiring the Plant Crist units to commit and operate to meet the transmission requirements. The fuel and must-run production cost NPVs for Option 1 range from $[redacted] to $[redacted]M across the range of integrated system scenarios; Option 2 ranges from $[redacted] to $[redacted]M; and Option 3 ranges from $[redacted] to $[redacted] M. Option 4, transmission upgrades only, had zero fuel or must run cost.

The emission control retrofits NPV was only a factor in Option 2, the gas and coal combination. It had an estimated NPV cost of $[redacted]M for the ACI and DSI controls needed to lower acid gas and mercury emissions.

Table 3.3-1
Plant Crist MATS Analysis
NPV 2013 in millions

Option	Transmission NPV	Fuel and Must Run Production Costs NPV	Emission Controls NPV	Total all NPV Costs
Option 1: Natural Gas	[redacted]	[redacted]	$0	[redacted]
Option 2: Natural Gas and Coal	[redacted]	[redacted]	[redacted]	[redacted]
Option 3: Natural Gas and Transmission Upgrades	[redacted]	[redacted]	$0	[redacted]
Option 4: Transmission Upgrades Only	[redacted]	$0	$0	[redacted]

Plant Crist MATS Conclusion

Option 1 had the highest total NPV cost by a large margin. Therefore, it was eliminated from further consideration.

The cost of Option 2 was the next highest of the four options. Option 2 has plant operational risks associated with operating an emission control system intermittently and handling a secondary coal supply. In addition, uncertainty surrounding the potential effects the injection additives may have on compliance with current land- and water-based environmental rules increased the risk associated with Option 2. Furthermore, the coal pile at Plant Crist has already been reduced in size to accommodate existing environmental controls. The coal pile area today could not support two separate coal inventories, which would be required under this option. For these cost and operational reasons, Option 2 was eliminated from consideration.

The low end of the cost range for Option 3 was comparable to, but still higher than, the lowest cost option, Option 4. The high end of the cost range for Option 3 was well above the cost of Option 4. The cost of Option 3 is also subject to future natural gas price volatility and other variable market conditions which leave Gulf's customers exposed to the risk of costly must-run operations rather than the benefit of operating the Plant Crist units in economic system dispatch. Additionally, this option required a commitment to generate [redacted] MW with only natural gas firing during scrubber bypass. This operational constraint at Plant Crist would require an engineering study to more fully understand the operational challenges of this option.

Option 4, transmission upgrades only, had the lowest total NPV cost and has the lowest risk of the four options. The costs associated with Option 4 have a higher level of certainty, and the transmission upgrades do not cause any plant operational risks or costly must-run constraints. Option 4 has the benefit of removing the must-run requirement from Plant Crist, which will allow Gulf to operate the plant the most economically, generating a production cost savings for Gulf's customers as shown in Table 3.3-1. Therefore, it was determined that Option 4, transmission upgrades only, would be the lowest compliance cost and risk and therefore the best option for Gulf's customers.

Conclusions for Plant Crist

Based on previous economic assessments of Crist Units 4 through 7 and the Crist Unit 6 SCR economic evaluation, the retrofit of Crist Units 4 through 7 with a single scrubber, SNCRs on Units 4 and 5, and SCRs on Units 6 and 7 are the best options for compliance with the current requirements of CAIR, CAVR, and the anticipated NAAQS. These are the only technologies that offer the necessary emission reductions for SO_2 and NOx, and when used together, the scrubber and the SCRs on Units 6 and 7 provide additional benefit by reducing mercury emissions. Decisions regarding Gulf's CAIR compliance strategy were made jointly

with the CAVR and CAMR/MATS compliance plans due to co-benefits of proposed controls. As discussed above transmission upgrades are the lowest cost MATS compliance option for Plant Crist. The transmission upgrades have a higher level of certainty than Options 1, 2 or 3 and will not create any plant operational risks. The upgrades will also allow the plant to operate under economic dispatch rather than in must-run. The initial transmission upgrades are currently projected to be completed by April 2016 with the remaining projects being placed in-service by 2018.

The scrubber, mercury monitors, SNCRs, and SCRs have been approved for recovery through the ECRC in past proceedings, subject to ongoing review of costs within the ECRC annual review process. The MATS transmission upgrades were added to the Compliance Program during 2013 and have not been approved for ECRC recovery at this time. Gulf Power is requesting approval of inclusion of these projects in the Company's Compliance Program.

3.3.2 PLANT DANIEL

Gulf Power's ownership interest at Plant Daniel is associated with two coal-fired electric generating units that have a nameplate rating of 548.25 MW each. Gulf Power and Mississippi Power Company each own 50 percent of Daniel Units 1 and 2. The plant is operated by Mississippi Power. The facility is located just north of Pascagoula, Mississippi, with direct transmission access across Alabama and into Florida. Both coal-fired units were affected by the Acid Rain Program and have operated on low-sulfur coals since the 1990s. These New Source Performance Standards (NSPS) units are relatively low NOx emitters, and as a result, Gulf and Mississippi Power have been able to delay installation of controls and associated costs required under the Acid Rain Program. Low NOx burners were installed on Daniel Units 1 and 2 during 2010 and 2008, respectively, for CAIR annual and seasonal NOx cap and trade allowance programs.

For compliance with the CAIR, CAVR, MATS and anticipated NAAQS, Plant Daniel Units 1 and 2 need significant emission reductions. Only a few technologies have demonstrated the ability to provide the necessary emission reductions at the commercial scale required for the coal units at Plant Daniel. Retrofit options are each reviewed below specifically for Plant Daniel.

Plant Daniel Retrofit Options

Plant Daniel Unit 1 and Unit 2 Flue Gas Desulfurization Scrubber Projects

Very high levels of SO_2 emission reductions can be achieved by flue gas desulfurization. Other than flue gas desulfurization, there are no other commercially available options for SO_2 emission reductions at the level needed to assure compliance with the CAIR, CAVR, MATS, and the anticipated NAAQS. Flue gas desulfurization, or wet scrubbing, has been determined to be the only viable SO_2 retrofit compliance option for Plant Daniel.

The Daniel scrubber projects are designed to reduce SO_2 emissions by approximately 95%. With these reductions, Gulf Power will be able to reasonably manage compliance using its SO_2 allowance bank for the acid rain program and CAIR. The scrubber projects are currently scheduled for completion in the fall of 2015. Site development is approximately 75% complete, and all of the Phase I deep foundations have been installed. The scrubbers will minimize reliance on the SO_2 allowance market and allow Plant Daniel to comply with the MATS particulate matter (PM) and surrogate SO_2 limits as well as the CAIR, CAVR, and NAAQS rules.

Plant Daniel NOx Reduction Projects

The Daniel Unit 1 and 2 Low NOx burners were planned for CAIR annual and seasonal NOx cap and trade allowance programs. The Daniel Unit 2 Low NOx burners were installed during 2008 and the Unit 1 Low NOx burners were placed in-service in 2010.

The Plant Daniel Units 1 and 2 SCRs are now scheduled to be in service by 2020. The anticipated timeline for compliance with the revised ozone NAAQS has been deferred one year from 2019 to 2020. This timeline is subject to change because it is influenced by several different parties and factors, including the EPA and state regulatory agencies, atmospheric modeling, and ambient air quality. The NAAQS revisions are scheduled to be finalized in 2014. In addition to the NAAQS, the SCRs will help meet the requirements of the CAIR and the CAVR. The SCRs, along with the Unit 1 and 2 scrubbers, will provide a co-benefit of reducing mercury emissions and assisting in compliance with MATS.

Plant Daniel MATS Requirements

The MATS requirements apply to the coal-fired units at Plant Daniel. Plant Daniel emission data as well as data from other similar units (without scrubbers) indicate that while the MATS PM limit will be met, neither the acid gases nor the mercury limits will be met without installing additional environmental controls. The Company determined that at a minimum Plant Daniel Units 1 and 2 would require installation of scrubbers in order to comply with MATS as well as CAIR, CAVR, and the anticipated NAAQS. With the Plant Daniel scrubbers that are currently under construction, the acid gas limits will be achieved. The mercury emissions, however, will need to be reduced further to meet MATS limits. As explained in the following section, the best option to meet the MATS limits at Plant Daniel includes installing the already approved scrubbers and adding bromine injection, and activated carbon injection (ACI).

Plant Daniel MATS Options

After reviewing the proposed MATS rule, it was determined that additive injection upstream of the precipitator or a baghouse with ACI would be required for Plant Daniel Units 1 and 2 to comply with the MATS mercury standards. Each technology works in conjunction with the scrubbers to increase, by varying degrees, the total mercury removal. The construction lead-time requirements for bromine injection, ACI, or a baghouse with ACI are shorter than

the lead-time of the scrubber projects, which allowed the Company to wait for the final MATS rule to be published prior to committing to the ultimate MATS compliance strategy for Plant Daniel.

The bromine injection system would add bromine to the coal supply, which would cause mercury to be oxidized after combustion. Oxidized mercury can then be collected in the scrubbers. The ACI system is based on injecting powdered activated carbon into the duct work where it mixes with flue gas to absorb elemental mercury which is then captured in the precipitator.

Plant Daniel MATS Analysis and Conclusion

Testing completed for Plant Daniel has confirmed that bromine and ACI rather than more capital intensive controls such as baghouses with ACI will be sufficient to meet the final MATS standards. Gulf's 50% ownership costs for installing the injection systems is projected to be approximately $[redacted] million. This selection represents approximately $135 million in capital cost reductions when compared to the baghouse installation cost.

Engineering, procurement, and construction of the Plant Daniel bromine and ACI systems are scheduled to begin in January 2014 and last for approximately two years. Both injection systems will be placed in service with the scrubbers during fourth quarter of 2015.

Conclusions for Plant Daniel

The retrofit of Daniel Units 1 and 2 with scrubbers, bromine injection and ACI, the installation of Low-NOx burners, and the addition of SCRs on both units are the best options for compliance with the CAIR, MATS, CAVR, and the anticipated NAAQS. Fuel switching alone will not reduce emissions to the required level. Allowance purchases are too uncertain and risky as a sole compliance option and are not applicable for MATS compliance.

The scrubbers, low NOx burners, mercury monitors, and SCRs have been approved for recovery through the ECRC in past proceedings, subject to ongoing review of costs within the ECRC annual review process. This filing will update Gulf's Compliance Program to include the Plant Daniel bromine and ACI projects that have not been approved for ECRC recovery at this time. Gulf Power is requesting approval of inclusion of these projects in the Company's Compliance Program.

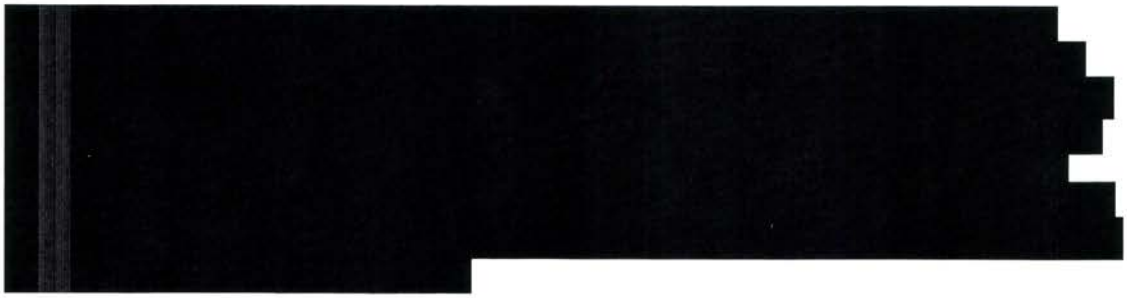
3.3.3 PLANT SMITH

Plant Smith includes two coal-fired electric generating units, Unit 1 and Unit 2, along with an oil-fired combustion turbine (CT) and a natural gas-fired combined cycle unit. The facility is located just north of Panama City, Florida. Plant Smith Unit 1 has a nameplate rating of 149.6 MW, and Unit 2 has a nameplate rating of 190.4 MW. Both coal-fired units were affected under the Acid Rain Program, and the plant has operated on low-sulfur coals since the 1990s to lower SO_2 emissions. Both units are also equipped with low-NOx combustion systems. Unit 1 has special low-NOx burner tips, and Unit 2 has low-NOx burners and separated overfired air.

The CAIR required the installation of a parametric emission monitoring system on the Plant Smith CT during 2007. Installation of SNCRs for Plant Smith Units 1 and 2 was needed for Phase I CAIR compliance in 2009. In addition to CAIR compliance, the SNCRs were needed to assist in maintaining local compliance with the anticipated 8-hour ozone non-attainment designation. The Smith Unit 2 SNCR was placed in-service in the fall of 2008, and the Smith Unit 1 SNCR was placed in-service during May of 2009.

Plant Smith MATS Requirements

Plant Smith Units 1 and 2 are subject to the MATS rule. Plant Smith emissions data, as well as data from similar units, indicate that while the MATS PM limit would be met, neither the acid gases nor the mercury limits will be met without additional emissions controls. Therefore, in order to continue operation of these Plant Smith units, additional environmental controls will be required to meet MATS limits. The analysis and the decision to install additional environmental controls on Plant Smith Units 1 and 2 for MATS compliance or to retire and replace is ongoing. However, due to the short MATS compliance window, this Compliance Plan update must address time sensitive transmission improvements that are caused by the requirements of the MATS rule.



The proposed transmission upgrades allow Gulf to defer the retirement versus controls decision until there is more certainty surrounding future environmental regulations such as 316(b), CCB and effluent guidelines. The final MATS strategy could potentially include air pollution equipment as well as land and water controls needed due to anticipated effects the injection additives may have on compliance with current land- and water-based environmental rules.

The following MATS scenarios and analysis show that installation of certain transmission upgrades are part of the most economic option for Gulf's customers in the event that additional emissions controls are installed on Plant Smith Units 1 and 2 for MATS compliance. The same transmission upgrades are required if these units retire as a result of MATS.

Plant Smith MATS Options

The MATS compliance options for Plant Smith include retirement of Plant Smith Units 1 and 2 as well as options that would allow continued coal-fired operation of Smith Units 1 and 2 as illustrated in Figure 3.3-2. Gulf first evaluated the available options that would allow Smith Units 1 and 2 to achieve compliance with applicable MATS requirements and to continue to operate in a manner that would satisfy its must-run transmission obligations.

If Smith Units 1 and 2 continue to operate on coal, new environmental controls are required. Available emission control systems were reviewed to determine the most cost-effective emission controls for these units to meet the MATS requirements. In previous Compliance Plan updates, Gulf indicated that a scrubber may be necessary to attain CAMR/MATS compliance at Plant Smith. Further evaluation of available control systems indicates that a lower cost emission control system is available for Plant Smith. This control system consists of ACI, DSI, conversion of the hot precipitators to cold precipitators, and the use of low sulfur and low chloride coal (collectively referred to as "MATS controls" hereafter). While the proposed MATS controls would allow Smith Units 1 and 2 to meet the MATS regulatory requirements, the controls would greatly increase the variable operating cost of Smith Units 1 and 2 due to the heavy use of sorbent injections as well as the use of a premium-priced coal for both units. Maintaining Smith Units 1 and 2 as must-run units with this increase in operation costs would have significant cost impacts to Gulf's customers over the remaining life of the two units. For that reason, Gulf evaluated two options that would allow for continued operation of Smith Units 1 and 2: Option 1- install MATS controls and continue to operate the three Plant Smith units as must-run, and Option 2 - install MATS controls along with additional transmission upgrades to eliminate the must-run status of Smith Units 1 and 2 (as well as Smith Unit 3). Following evaluation of these options, Gulf determined that Option 2, installing MATS controls along with additional transmission upgrades, is the most economic option for continued operation due to the high variable operating costs of Smith Units 1 and 2 caused by MATS compliance.

Unless replacement generation is constructed on-site to maintain the transmission reliability requirements (concurrent with the Smith Units 1 and 2 retirement), a retirement option for Plant Smith MATS compliance requires the addition of transmission improvements. On-site replacement generation for MATS is not feasible for several reasons: replacement generation capital costs are an order of magnitude above the capital costs of the transmission upgrades; the necessary gas lateral and annual firm transportation cost estimates are extremely cost prohibitive; and due to the short compliance timeframe of the MATS rule, construction of replacement generation is not possible by the MATS compliance date. This means that

transmission improvements are the most economic option for MATS compliance for either retirement or continued operation of Smith Units 1 and 2. Due to the long lead time required for the transmission improvements, Gulf must proceed immediately with these projects while continuing to evaluate the ultimate Compliance Plan—retirement/replacement or controls—for Smith Units 1 and 2.

Plant Smith- MATS Analysis

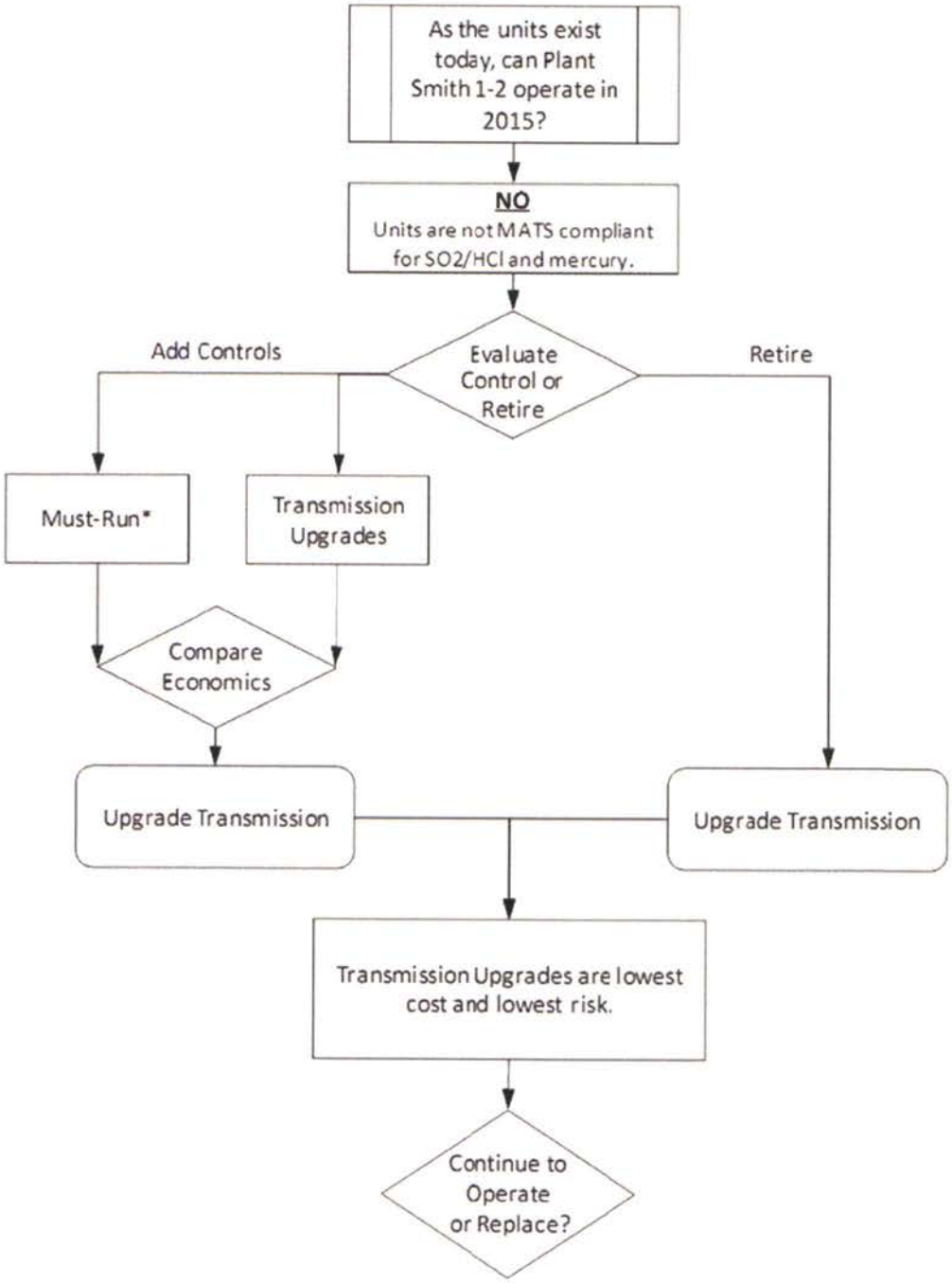


Figure 3.3-2 Plant Smith MATS Analysis

Plant Smith MATS Analysis

For each Plant Smith MATS option, the NPV of estimated revenue requirements was calculated for the transmission upgrades and must-run production costs. A summary of the NPV costs are provided in Table 3.3-2. The transmission NPV for Option 1 is the NPV cost of transmission projects that were projected to be needed in 2023 and beyond under the current must-run arrangement. This NPV is considered to be a base transmission cost. The Option 2 transmission NPV reflects a $[redacted]M higher cost due to acceleration of those transmission improvements which Gulf must now move forward with due to MATS under this compliance option.

The must-run production cost NPV is the increased production cost of requiring Plant Smith Units 1 through 3 to commit and operate to meet the transmission requirements. This must-run production cost NPV for Option 1 ranges from $[redacted] to $[redacted]M across the range of integrated system scenarios while Option 2, controls and transmission upgrades, had zero must-run cost.

Table 3.3-2
Plant Smith MATS Analysis
NPV 2013 in millions

Option	Transmission NPV	Must-Run Production Costs NPV	Total all NPV Costs
1 – Controls and continue Must-Run	[redacted]	[redacted]	[redacted]
2 – Controls and Transmission Upgrades	[redacted]	$0	[redacted]

Plant Smith MATS Conclusion

With Option 1 there is risk and uncertainty due to future fuel prices and CO_2 regulatory impacts. Option 2, MATS controls and transmission upgrades, had the lowest total NPV as well as lower risk and less uncertainty. This indicated that installation of the transmission upgrades, as a part of the MATS compliance strategy, is the most cost-effective option for continued operation. Proceeding with the transmission upgrades evaluated in Option 2, which were also identified as being necessary under a retirement option, preserves the decision to install MATS controls or to retire the two units for a future time when more is known with regard to costs of compliance requirements associated with additional environmental regulations. Therefore, Gulf determined that the first part of the MATS compliance strategy for Plant Smith is the installation of the transmission upgrades required in Option 2. Gulf will submit revisions to its environmental Compliance Program for the Commission's review after a decision is made either to install additional MATS controls or to retire the units.

Conclusions for Plant Smith

The retrofit of Smith Units 1 and 2 with SNCRs and the installation of a CAIR parametric monitor for the CT were the best option for compliance with CAIR as described in Gulf's original Compliance Plan evaluations. The CT parametric monitor was placed in-service in 2007. The Smith Unit 2 SNCR was placed in-service in the fall of 2008 and the Smith Unit 1 SNCR was placed in-service during May of 2009.

The Plant Smith scrubber and baghouse projects were originally included in Gulf's Compliance Program for future consideration; however, it has been determined that the projects are no longer viable compliance options. The Plant Smith Units 1 and 2 scrubber and the Plant Smith baghouse projects have been removed from Gulf's Compliance Program.

Further evaluation of available control systems indicates that a lower cost MATS emission control system is available for Plant Smith. This control system consists of ACI, DSI, conversion of the hot precipitators to cold precipitators, and the use of low sulfur/low chloride coal. This proposed MATS strategy for Plant Smith also meets the proposed Florida SIP requirements for CAVR /BART.

The analysis and decision to install additional MATS controls or to retire and replace the units have not yet been completed. However, Gulf has determined that transmission improvements are the most economic option for MATS compliance for either retirement or continued operation of Smith Units 1 and 2. The transmission upgrades are currently projected to be completed in 2015. The proposed transmission upgrades allow Gulf to defer the retirement decision until there is more certainty surrounding future environmental regulations such as 316(b), CCB, and effluent guidelines. Once the Company determines the most cost-effective overall compliance options for Plant Smith, Gulf will submit revisions to the environmental Compliance Program for the Commission's review. As stated previously, the plans for compliance could include air and water improvements to meet regulatory requirements.

The CAIR parametric monitor, mercury monitor, and SNCRs have been approved for recovery through the ECRC in past proceedings, subject to ongoing review of costs within the ECRC annual review process. The MATS transmission upgrades have not been approved for recovery through the ECRC at this time. Gulf Power is requesting approval of inclusion of the MATS transmission projects in the Company's Compliance Program.

3.3.4 PLANT SCHOLZ

Plant Scholz consists of two coal-fired electric generating units that each have a nameplate rating of 49 MW. The facility is located in Jackson County, Florida. Both units were affected under the Acid Rain Program, and the plant has operated on low-sulfur coals since the 1990s to lower SO_2 emissions. Because these units are small and older, NOx averaging was used to achieve compliance with the NOx requirements under the Acid Rain Program without the installation of emission control equipment.

For CAIR and CAVR requirements at Plant Scholz, a thorough assessment was conducted to compare retrofit controls versus retirement and replacement options for compliance. Fuel switching, allowance purchases, and emission control retrofit versus retirement and replacement were all evaluated as options for compliance. Because this small plant is nearing retirement, significant investments in capital equipment to reduce emissions cannot be justified economically. The plant will utilize Company-wide allowance trading options rather than installing additional emission control equipment for CAIR compliance. In response to finalization and evaluation of the MATS rule, Gulf has decided to cease coal-fired operation of Plant Scholz as of April 1, 2015. Gulf has determined that it is not economical to add the environmental controls at Plant Scholz necessary to comply with MATS.

4.0 POTENTIAL NEW ENVIRONMENTAL REGULATIONS

4.1 EPA'S EXCESS EMISSION STATE IMPLEMENTATION PLANS

On February 12, 2013, the EPA proposed a rule that would require certain states to revise their State Implementation Plans (SIPs) relating to the regulation of excess emissions at industrial facilities, including fossil fuel-fired generating facilities, during periods of startup, shut-down, or malfunction (SSM). The EPA proposed a determination that the SSM provisions in the SIPs for 36 states (including Florida and Mississippi) do not meet the requirements of the Clean Air Act and must be revised within 18 months of the date on which the EPA publishes the final rule. If finalized as proposed, this new requirement could result in additional compliance and operational costs.

4.2 GLOBAL CLIMATE ISSUES

The EPA regulates greenhouse gases under the Clean Air Act (CAA). In addition, over the past several years, the U.S. Congress has considered many proposals to reduce greenhouse gas emissions, mandate renewable or clean energy, and impose energy efficiency standards. Such proposals are expected to continue to be considered by the U.S. Congress. International climate change negotiations under the United Nations Framework Convention on Climate Change are also continuing. The financial and operational impacts of climate or energy legislation, if enacted, would depend on a variety of factors, including the specific provisions and timing of any legislation that might ultimately be adopted.

In April 2007, the U.S. Supreme Court ruled that carbon dioxide (CO_2) and GHGs could be considered "pollutants" under the CAA and that the EPA must decide whether emissions of these pollutants endanger public health and welfare. The EPA's final endangerment finding (December 2009) provided the "cause" for the EPA to regulate GHGs which it has done through a number of subsequent actions including the Light Duty Vehicle Rule (April 2010). The Light Duty Vehicle Rule made GHGs "regulated pollutants" under the CAA and triggered stationary source permitting requirements for GHGs. The Tailoring Rule (May 2010) changed the permitting emission thresholds and detailed a phased approach for GHG stationary source permitting requirements. As of January 2, 2011 new and modified stationary sources that have GHG emissions over the thresholds must go through the prevention of significant deterioration permitting process including installation of the best available control technology for CO_2 and other GHGs. Greenhouse gases must also be addressed in existing Title V operating permits as the permits are renewed.

In April 2012, the EPA proposed GHG New Source Performance Standards for future new fossil fuel-fired electric generating units. The proposed rule sets the standard at 1,000 pounds of CO_2 per megawatt hour and it includes an option for new coal-fired units to use a 30-year average to meet the standard rather than having to meet the standard annually. This rule could impact the flexibility and operations of new natural gas combined-cycle units and

would eliminate new coal-fired electric generation unless it includes carbon capture and storage. In addition to these rules, the EPA has announced plans to develop federal guidelines for states to establish GHG performance standards for existing units.

Each of the EPA's final CAA rulemakings (the Endangerment Finding, the Light Duty Vehicle Rule, and the Tailoring Rule) were challenged in the U.S. Court of Appeals for the District of Columbia Circuit. On June 26, 2012, the Court issued its decisions to dismiss or deny these cases, and on December 20, 2012, the U.S. Court of appeals for the District of Columbia Circuit rejected an industry-backed request to reconsider its decision to uphold the GHG regulations.

International climate change negotiations under the United Nations Framework Convention on Climate Change also continue. In 2009, a nonbinding agreement known as the Copenhagen Accord was reached that included a pledge from countries to reduce their GHG emissions. The 2012 negotiations took place in Doha, Qatar from November 26 to December 7, 2012. These negotiations resulted in a plan of action to develop the legal instrument by the end of the 2015 negotiations as required by 2011's Durban Agreement. Also, a second commitment period under the Kyoto Protocol was established that will run from January 1, 2013, to 2020. The U.S. is not part of this second commitment period since it is not a party to the Kyoto Protocol. The outcome and impact of the international negotiations cannot be determined at this time.

Although the outcome of federal and international initiatives cannot be determined at this time, additional restrictions on the Company's GHG emissions or requirements relating to renewable energy or energy efficiency at the federal or state level are likely to result in significant additional compliance costs, including significant capital expenditures. These costs could affect future unit retirement and replacement decisions and could result in the retirement of a significant number of coal-fired generating units.

4.3 COAL COMBUSTION BYPRODUCTS (CCB) REGULATION

The EPA continues to evaluate the regulatory program for coal combustion byproducts including coal ash and gypsum under federal solid and hazardous waste laws. In June 2010, the EPA published a proposed rule that requested comments on two potential regulatory options for the management and disposal of coal combustion byproducts: regulation as a solid waste or regulation as if the materials technically constituted a hazardous waste. Adoption of either option could require closure of, or significant change to, existing storage facilities and construction of lined landfills, as well as additional waste management and groundwater monitoring requirements. Under both options, the EPA proposes to exempt the beneficial reuse of coal combustion byproducts from regulation; however, a hazardous or other designation indicative of heightened risk could limit or eliminate beneficial reuse options. Environmental groups and other parties have filed lawsuits in the U.S. District Court for the District of Columbia seeking to require the EPA to complete its rulemaking process and issue final regulations pertaining to the regulation of coal combustion byproducts. In

addition to the EPAs rulemaking for CCBs, Congress has made multiple attempts to pass coal ash legislation.

The Company currently operates three coal-fired electric generating plants in Florida and is part owner of Plant Daniel Units 1 and 2 located in Mississippi. Each plant has on-site coal combustion byproducts storage facilities. In addition to on-site storage, the Company sells a portion of its coal combustion byproducts to third parties for beneficial reuse. Historically, individual states have regulated coal combustion byproducts and the States of Florida and Mississippi each have their own regulatory parameters. The Company has a routine and robust inspection program in place to ensure the integrity of its CCB surface impoundments and compliance with applicable regulations.

4.4 316(B) INTAKE STRUCTURE REGULATION

In April 2011, the EPA published a proposed rule that establishes standards for reducing effects on fish and other aquatic life caused by cooling water intake structures at existing power plants and manufacturing facilities. The rule also addresses cooling water intake structures for new units at existing facilities. Compliance with the proposed rule could require changes to existing cooling water intake structures at certain generating facilities, and new generating units constructed at existing plants would be required to install closed cycle cooling towers. The EPA has entered into an amended settlement agreement to extend the deadline for issuing a final rule until June 27, 2013. If finalized as proposed, some of the Company's facilities may be subject to significant additional capital expenditures and compliance costs that could affect future unit retirement and replacement decisions. The ultimate outcome of this rulemaking will depend on the final rule and the outcome of any legal challenges and cannot be determined at this time.

4.5 EFFLUENT LIMITATIONS GUIDELINES

On September 15, 2009, the EPA announced its plans to commence a rulemaking to revise the current effluent guidelines for steam electric generating plants. The EPA completed a multi-year study of power plant wastewater discharges and concluded that pollutant discharges from coal-fired power plants will increase significantly in the next few years as new air pollution controls are installed. The EPA's study concludes that technologies are available to significantly reduce pollutant loadings from ash transport water and Flue Gas Desulfurization (FGD) scrubber wastewater. The EPA is scheduled to propose a rule by April 19, 2013 and finalize it by May 22, 2014. New advanced wastewater treatment requirements are expected and may result in the installation of additional controls on certain facilities. The impact of the revised guidelines will depend on the specific technology requirements of the final rule and, therefore, cannot be determined at this time.

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO.	130140-EI	**EXHIBIT**	10
PARTY	Gulf Power Company (Gulf) Direct		
DESCRIPTION	James O. Vick (JOV-2)		

Docket No. 130140-EI
Mercury and Air Toxics Standards
Exhibit JOV-2, Page 1 of 210

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 60 and 63

[EPA–HQ–OAR–2009–0234; EPA–HQ–OAR–2011–0044, FRL–9611–4]

RIN 2060–AP52; RIN 2060–AR31

National Emission Standards for Hazardous Air Pollutants From Coal- and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: On May 3, 2011, under authority of Clean Air Act (CAA) sections 111 and 112, the EPA proposed both national emission standards for hazardous air pollutants (NESHAP) from coal- and oil-fired electric utility steam generating units (EGUs) and standards of performance for fossil-fuel-fired electric utility, industrial-commercial-institutional, and small industrial-commercial-institutional steam generating units (76 FR 24976). After consideration of public comments, the EPA is finalizing these rules in this action.

Pursuant to CAA section 111, the EPA is revising standards of performance in response to a voluntary remand of a final rule. Specifically, we are amending new source performance standards (NSPS) after analysis of the public comments we received. We are also finalizing several minor amendments, technical clarifications, and corrections to existing NSPS provisions for fossil fuel-fired EGUs and large and small industrial-commercial-institutional steam generating units.

Pursuant to CAA section 112, the EPA is establishing NESHAP that will require coal- and oil-fired EGUs to meet hazardous air pollutant (HAP) standards reflecting the application of the maximum achievable control technology. This rule protects air quality and promotes public health by reducing emissions of the HAP listed in CAA section 112(b)(1).

DATES: This final rule is effective on April 16, 2012. The incorporation by reference of certain publications listed in this rule is approved by the Director of the Federal Register as of April 16, 2012.

ADDRESSES: The EPA established two dockets for this action: Docket ID. No. EPA–HQ–OAR–2011–0044 (NSPS action) or Docket ID No. EPA–HQ–OAR–2009–0234 (NESHAP action). All documents in the dockets are listed on the *http://www.regulations.gov* Web site. Although listed in the index, some information is not publicly available, e.g., confidential business information or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the Internet and will be publicly available only in hard copy form. Publicly available docket materials are available either electronically through *http://www.regulations.gov* or in hard copy at EPA's Docket Center, Public Reading Room, EPA West Building, Room 3334, 1301 Constitution Avenue NW., Washington, DC 20004. This Docket Facility is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Public Reading Room is (202) 566–1744, and the telephone number for the Air Docket is (202) 566–1741.

FOR FURTHER INFORMATION CONTACT: For the NESHAP action: Mr. William Maxwell, Energy Strategies Group, Sector Policies and Programs Division, (D243–01), Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711; Telephone number: (919) 541–5430; Fax number (919) 541–5450; Email address: *maxwell.bill@epa.gov.* For the NSPS action: Mr. Christian Fellner, Energy Strategies Group, Sector Policies and Programs Division, (D243–01), Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711; Telephone number: (919) 541–4003; Fax number (919) 541–5450; Email address: *fellner.christian@epa.gov.*

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I. General Information

A. Does this action apply to me?

The regulated categories and entities potentially affected by the final standards are shown in Table 1 of this preamble.

TABLE 1—POTENTIALLY AFFECTED REGULATED CATEGORIES AND ENTITIES

Category	NAICS code [1]	Examples of potentially regulated entities
Industry	221112	Fossil fuel-fired electric utility steam generating units.
Federal government	[2] 221122	Fossil fuel-fired electric utility steam generating units owned by the federal government.
State/local/tribal government	[2] 221122	Fossil fuel-fired electric utility steam generating units owned by states, tribes, or municipalities.
	921150	Fossil fuel-fired electric utility steam generating units in Indian country.

[1] North American Industry Classification System.
[2] Federal, state, or local government-owned and operated establishments are classified according to the activity in which they are engaged.

This table is not intended to be exhaustive, but rather is meant to provide a guide for readers regarding entities likely to be affected by this action. To determine whether you, as owner or operator of a facility, company, business, organization, etc., will be regulated by this action, you should examine the applicability criteria in 40 CFR 60.40, 60.40Da, or 60.40c or in 40 CFR 63.9981. If you have any questions regarding the applicability of this action to a particular entity, consult either the air permitting authority for the entity or your EPA regional representative as listed in 40 CFR 60.4 or 40 CFR 63.13 (General Provisions).

B. Where can I get a copy of this document?

In addition to being available in the dockets, an electronic copy of this action will also be available on the Worldwide Web (WWW) through the Technology Transfer Network (TTN). Following signature by the Administrator, a copy of the action will be posted on the TTN's policy and guidance page for newly proposed or promulgated rules at the following address: *http://www.epa.gov/ttn/oarpg/*. The TTN provides information and technology exchange in various areas of air pollution control.

C. Judicial Review

Under CAA section 307(b)(1), judicial review of this final rule is available only by filing a petition for review in the U.S. Court of Appeals for the District of Columbia Circuit by April 16, 2012. Under CAA section 307(d)(7)(B), only an objection to this final rule that was raised with reasonable specificity during the period for public comment (including any public hearing) can be raised during judicial review. This section also provides a mechanism for the EPA to convene a proceeding for reconsideration, "[i]f the person raising an objection can demonstrate to the Administrator that it was impracticable to raise such objection within [the period for public comment] or if the grounds for such objection arose after the period for public comment (but within the time specified for judicial review) and if such objection is of central relevance to the outcome of the rule[.]" Any person seeking to make such a demonstration to us should submit a Petition for Reconsideration to the Office of the Administrator, Environmental Protection Agency, Room 3000, Ariel Rios Building, 1200 Pennsylvania Ave. NW., Washington, DC 20004, with a copy to the person listed in the preceding **FOR FURTHER INFORMATION CONTACT** section, and the Associate General Counsel for the Air and Radiation Law Office, Office of General Counsel (Mail Code 2344A), Environmental Protection Agency, 1200 Pennsylvania Ave. NW., Washington, DC 20004. Note, under CAA section 307(b)(2), the requirements established by this final rule may not be challenged separately in any civil or criminal proceedings brought by EPA to enforce these requirements.

D. What are the costs and benefits of this final rule?

Consistent with Executive Order (EO) 13563, "Improving Regulation and Regulatory Review," we have estimated the costs and benefits of the final rule. This rule will reduce emissions of HAP, including mercury (Hg), from the electric power industry. Installing the technology necessary to reduce emissions directly regulated by this rule will also reduce the emissions of directly emitted $PM_{2.5}$ and sulfur dioxide (SO_2), a $PM_{2.5}$ precursor. The benefits associated with these PM and SO_2 reductions are referred to as co-benefits, as these reductions are not the primary objective of this rule.

The EPA estimates that this final rule will yield annual monetized benefits (in 2007$) of between $37 to $90 billion using a 3 percent discount rate and $33 to $81 billion using a 7 percent discount rate. The great majority of the estimates are attributable to co-benefits from reductions in $PM_{2.5}$-related mortality. The annual social costs, approximated

by the sum of the compliance costs and monitoring and reporting costs, are $9.6 billion (2007$) and the annual quantified net benefits (the difference between benefits and costs) are $27 to $80 billion using a 3 percent discount rate or $24 to $71 billion using a 7 percent discount rate. It is important to note that the $PM_{2.5}$ co-benefits reported here contain uncertainty, due in part to the important assumption that all fine particles are equally potent in causing premature mortality and because many of the benefits are associated with reducing $PM_{2.5}$ levels at the low end of the concentration distributions examined in the epidemiology studies from which the $PM_{2.5}$-mortality relationships used in this analysis are derived.

The benefits of this rule outweigh costs by between 3 to 1 or 9 to 1 depending on the benefit estimate and discount rate used. The co-benefits are substantially attributable to the 4,200 to 11,000 fewer $PM_{2.5}$-related premature mortalities estimated to occur as a result of this rule. The EPA could not monetize some costs and important benefits, such as some Hg benefits and those for the HAP reduced by this final rule other than Hg. Upon considering these limitations and uncertainties, it remains clear that the benefits of this rule, referred to in short as the Mercury and Air Toxics Standards (MATS), are substantial and far outweigh the costs.

TABLE 2—SUMMARY OF THE MONETIZED BENEFITS, SOCIAL COSTS, AND NET BENEFITS FOR THE FINAL RULE IN 2016

[Billions of 2007$] [a]

	3% Discount rate	7% Discount rate
Total Monetized Benefits [b]	$37 to $90	$33 to $81.
Partial Hg-related Benefits [c]	$0.004 to $0.006	$0.0005 to $0.001.
$PM_{2.5}$-related Co-benefits [b]	$36 to $89	$33 to $80.
Climate-related Co-Benefits [d]	$0.36	$0.36.
Total Social Costs [e]	$9.6	$9.6.
Net Benefits	$27 to $80	$24 to $71.
Non-monetized Benefits	Visibility in Class I areas. Other neurological effects of Hg exposure. Other health effects of Hg exposure. Health effects of ozone and direct exposure to SO_2 and NO_2. Ecosystem effects. Health effects from commercial and non-freshwater fish consumption. Health risks from exposure to non-mercury HAP.	

[a] All estimates are for 2016, and are rounded to two significant figures.

[b] The total monetized benefits reflect the human health benefits associated with reducing exposure to $PM_{2.5}$. The reduction in premature fatalities each year accounts for over 90 percent of total monetized benefits. Benefits in this table are nationwide and are associated with directly emitted $PM_{2.5}$ and SO_2 reductions. The estimate of social benefits also includes CO_2-related benefits calculated using the social cost of carbon, discussed further in chapter 5 of the RIA. Mercury benefits were calculated using the baseline from proposal. The difference in emissions reductions between proposal and final does not substantially affect the Hg benefits.

[c] Based on an analysis of health effects due to recreational freshwater fish consumption.

[d] This table shows monetized CO_2 co-benefits that were calculated using the global average social cost of carbon estimate at a 3 percent discount rate. In section 5.6 of the Regulatory Impact Analysis (RIA) we also report the monetized CO_2 co-benefits using discount rates of 5 percent, 2.5 percent, and 3 percent (95th percentile).

[e] Total social costs are approximated by the compliance costs for both coal- and oil-fired units. This includes monitoring, recordkeeping, and reporting costs.

For more information on how EPA is addressing EO 13563, see the EO discussion in the Statutory and Executive Order Reviews section of this preamble.

II. Background Information on the NESHAP

On May 3, 2011, the EPA proposed this rule to address emissions of toxic air pollutants from coal and oil-fired electric generating units as required by the CAA. The proposal explained at length the statutory history and requirements leading to this rule, the factual and legal basis for the rule and its specific provisions, and the costs and benefits to the public health and environment from the proposed requirements.

The EPA received over 900,000 comments from members of the public on the proposed rule, substantially more than for any other prior regulatory proposal. The comments express concerns about the presence of Hg in the environment and the effect it has on human health, concerns about the costs of the rule, how challenging it may be for some sources to comply and questions about the impact it may have on this country's electricity supply and economy. Many comments provided additional information and data that have enriched the factual record and enabled EPA to finalize a rule that fulfills the mandate of the CAA while providing flexibility and compliance options to affected sources—options that make the rule less costly and compliance more readily manageable.

This rule establishes uniform emissions-control standards that sources can meet with proven and available technologies and operational processes in a timeframe that is achievable. They will put this industry, now the single largest source of Hg emissions in the United States (U.S.) with emissions of 29 tons per year, on a path to reducing those emissions by approximately 90 percent. Emissions of other toxic metals, such as arsenic (As) and nickel (Ni), dioxins and furans, acid gases (including hydrochloric acid (HCl) and SO_2) will also decrease dramatically with the installation of pollution controls. And the flexibilities established in this rule along with other available tools provide a clear pathway to compliance without jeopardizing the country's energy supply.

This preamble explains EPA's appropriate and necessary finding, the elements of the final rule, key changes the EPA is making in response to comments submitted on the proposed rule, and our responses to many of the comments we received. A full response to comments is provided in the response to comments document available in the docket for this rulemaking.

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Mercury and Air Toxics Standards
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A. What is the statutory authority for this final rule?

Congress established a specific structure for determining whether to regulate EGUs under CAA section 112.[1] Specifically, Congress enacted CAA section 112(n)(1).

Section 112(n)(1)(A) of the CAA requires the EPA to conduct a study to evaluate the remaining public health hazards that are reasonably anticipated to occur as a result of EGUs' HAP emissions after imposition of CAA requirements. The EPA must report the results of that study to Congress, and regulate EGUs "if the Administrator finds such regulation is appropriate and necessary," after considering the results of that study. Thus, CAA section 112(n)(1)(A) governs how the Administrator decides whether to list EGUs for regulation under CAA section 112. *See New Jersey* v. *EPA*, 517 F.3d 574 at 582 (D.C. Cir. 2008) ("Section 112(n)(1) governs how the Administrator decides whether to list EGUs; it says nothing about delisting EGUs.").

As directed, the EPA conducted the study to evaluate the remaining public health hazards and reported the results to Congress (Utility Study Report to Congress (Utility Study)).[2] We discuss this study below in conjunction with other studies that CAA section 112(n)(1) requires concerning EGUs. See also 76 FR 24982–24984 (summarizing studies).

Once the EPA lists a source category pursuant to CAA section 112(c), the EPA must then establish technology-based emission standards under CAA section 112(d). For major sources, the EPA must establish emission standards that "require the maximum degree of reduction in emissions of the hazardous air pollutants subject to this section" that the EPA determines are achievable taking into account certain statutory factors. *See* CAA section 112(d)(2). These standards are referred to as "maximum achievable control technology" or "MACT" standards. The MACT standards for existing sources must be at least as stringent as the average emission limitation achieved by the best performing 12 percent of existing sources in the category (for which the Administrator has emissions information) or the best performing 5 sources for source categories with less than 30 sources. *See* CAA section 112(d)(3)(A) and (B), respectively. This level of minimum stringency is referred to as the "MACT floor," and the EPA cannot consider cost in setting the floor. For new sources, MACT standards must be at least as stringent as the control level achieved in practice by the best controlled similar source. *See* CAA section 112(d)(3).

The EPA also must consider more stringent "beyond-the-floor" control options. When considering beyond-the-floor options, the EPA must consider the maximum degree of reduction in HAP emissions and take into account costs, energy, and non-air quality health and environmental impacts when doing so. *See Cement Kiln Recycling Coal.* v. *EPA*, 255 F.3d 855, 857–58 (D.C. Cir. 2001).

Alternatively, the EPA may set a health-based standard for HAP that have an established health threshold, and the standard must provide "an ample margin of safety." *See* CAA section 112(d)(4). As these standards could be less stringent than MACT standards, the Agency must have detailed information on HAP emissions from the subject sources and sources located near the subject sources before exercising its discretion to set such standards.

For area sources, the EPA may issue standards or requirements that provide for the use of generally available control technologies or management practices (GACT standards) in lieu of promulgating MACT or health-based standards. *See* CAA section 112(d)(5).

As noted above, CAA section 112(n) requires completion of various reports concerning EGUs. For the first report, the Utility Study, Congress required the EPA to evaluate the hazards to public health reasonably anticipated to occur as the result of HAP emissions from EGUs after imposition of the requirements of the CAA. *See* CAA section 112(n)(1)(A). The EPA was required to report results from this study to Congress by November 15, 1993. *Id.* Congress also directed the EPA to conduct "a study of mercury emissions from [EGUs], municipal waste combustion units, and other sources, including area sources" (Mercury Study). *See* CAA section 112(n)(1)(B). The EPA was required to report the results from this study to Congress by November 15, 1994. *Id.* In conducting this Mercury Study, Congress directed the EPA to "consider the rate and mass of such emissions, the health and environmental effects of such emissions, technologies which are available to control such emissions, and the costs of such technologies." *Id.* Congress directed the National Institute of Environmental Health Sciences (NIEHS) to conduct the last required evaluation, "a study to determine the threshold level of mercury exposure below which adverse human health effects are not expected to occur" (NIEHS Study). *See* CAA section 112(n)(1)(C). The NIEHS was required to submit the results to Congress by November 15, 1993. *Id.* In conducting this study, NIEHS was to determine "a threshold for mercury concentrations in the tissue of fish which may be consumed (including consumption by sensitive populations) without adverse effects to public health." *Id.*

In addition, Congress, in conference report language associated with the EPA's fiscal year 1999 appropriations, directed the EPA to fund the National Academy of Sciences (NAS) to perform an independent evaluation of the available data related to the health impacts of methylmercury (MeHg) (NAS Study or MeHg Study). H.R. Conf. Rep. No 105–769, at 281–282 (1998). Specifically, Congress required NAS to advise the EPA as to the appropriate reference dose (RfD) for MeHg. 65 FR 79826. The RfD is the amount of a chemical which, when ingested daily over a lifetime, is anticipated to be without adverse health effects to humans, including sensitive subpopulations. In the same conference report, Congress indicated that the EPA should not make the appropriate and necessary regulatory determination for Hg emissions until the EPA had reviewed the results of the NAS Study. *See* H.R. Conf. Rep. No 105–769, at 281–282 (1998).

As directed by Congress through different vehicles, the NAS Study and the NIEHS Study evaluated the same issues. The NIEHS completed the NIEHS Study in 1995,[3] and the NAS completed the NAS Study in 2000.[4] Because NAS completed its study 5 years after the NIEHS Study, and considered additional information not earlier available to NIEHS, for purposes of this document we discuss the content of the NAS Study as opposed to the NIEHS Study.

The EPA conducted the studies required by CAA section 112(n)(1) concerning utility HAP emissions, the Utility Study and the Mercury Study,[5] and completed both by 1998. Prior to issuance of the Mercury Study, the EPA

[1] "Electric utility steam generating unit" is defined, in part, as any "fossil fuel fired combustion unit of more than 25 megawatts that serves a generator that produces electricity for sale." *See* CAA section 112(a)(8).

[2] U.S. EPA. Study of Hazardous Air Pollutant Emissions from Electric Utility Steam Generating Units—Final Report to Congress. EPA–453/R–98–004a. February 1998.

[3] NIEHS Study, August 1995; EPA–HQ–OAR–2009–3053.

[4] National Research Council (NAS). 2000. Toxicological Effects of Methylmercury. Committee on the Toxicological Effects of Methylmercury, Board on Environmental Studies and Toxicology, National Research Council.

[5] Mercury Study Report to Congress, December 1997; EPA–HQ–OAR–2009–0234–3054.

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engaged in two extensive external peer reviews of the document.

On December 20, 2000, the EPA issued a finding pursuant to CAA section 112(n)(1)(A) that it was appropriate and necessary to regulate coal- and oil-fired EGUs under CAA section 112 and added such units to the list of source categories subject to regulation under CAA section 112(d). In making that finding, the EPA considered the Utility Study, the Mercury Study, the NAS Study, and certain additional information, including information about Hg emissions from coal-fired EGUs that the EPA obtained pursuant to an information collection request (ICR) under the authority of CAA section 114. 65 FR 79826–27.

B. What is the litigation history of this final rule?

Shortly after issuance of the December 2000 finding, an industry group challenged that finding in the Court of Appeals for the D.C. Circuit (D.C. Circuit). *Utility Air Regulatory Group (UARG)* v. *EPA*, 2001 WL 936363, No. 01–1074 (D.C. Cir. July 26, 2001). The D.C. Circuit dismissed the lawsuit holding that it did not have jurisdiction because CAA section 112(e)(4) provides, in pertinent part, that "no action of the Administrator * * * listing a source category or subcategory under subsection (c) of this section *shall be a final agency action subject to judicial review*, except that any such action may be reviewed under section 7607 of (the CAA) when the Administrator issues emission standards for such pollutant or category." *Id. (emphasis added).*

Pursuant to a settlement agreement, the deadline for issuing emission standards was March 15, 2005. However, instead of issuing emission standards pursuant to CAA section 112(d), on March 29, 2005, the EPA issued the Section 112(n) Revision Rule (2005 Action). That action delisted EGUs after finding that it was neither appropriate nor necessary to regulate such units under CAA section 112. In addition, on May 18, 2005, the EPA issued the Clean Air Mercury Rule (CAMR). 70 FR 28606. That rule established standards of performance for emissions of Hg from new and existing coal-fired EGUs pursuant to CAA section 111.

Environmental groups, states, and tribes challenged the 2005 Action and CAMR. Among other things, the environmental and state petitioners argued that the EPA could not remove EGUs from the CAA section 112(c) source category list without following the requirements of CAA section 112(c)(9).

On February 8, 2008, the D.C. Circuit vacated both the 2005 Action and CAMR. The D.C. Circuit held that the EPA failed to comply with the requirements of CAA section 112(c)(9) for delisting source categories. Specifically, the D.C. Circuit held that CAA section 112(c)(9) applies to the removal of "any source category" from the CAA section 112(c) list, including EGUs. The D.C. Circuit found that, by enacting CAA section 112(c)(9), Congress limited the EPA's discretion to reverse itself and remove source categories from the CAA section 112(c) list. The D.C. Circuit found that the EPA's contrary position would "nullify § 112(c)(9) altogether." *New Jersey* v. *EPA*, 517 F.3d 574, 583 (D.C. Cir. 2008). The D.C. Circuit did not reach the merits of petitioners' arguments on CAMR, but vacated CAMR for existing sources because coal-fired EGUs were already listed sources under CAA section 112. The D.C. Circuit reasoned that even under the EPA's own interpretation of the CAA, regulation of existing sources' Hg emissions under CAA section 111 was prohibited if those sources were a listed source category under CAA section 112.[6] *Id.* The D.C. Circuit vacated and remanded CAMR for new sources because it concluded that the assumptions the EPA made when issuing CAMR for new sources were no longer accurate (*i.e.*, that there would be no CAA section 112 regulation of EGUs and that the CAA section 111 standards would be accompanied by standards for existing sources). *Id.* at 583–84. Thus, CAMR and the 2005 Action became null and void.

On December 18, 2008, several environmental and public health organizations filed a complaint in the U.S. District Court for the District of Columbia.[7] They alleged that the Agency had failed to perform a nondiscretionary duty under CAA section 304(a)(2), by failing to promulgate final CAA section 112(d) standards for HAP from coal- and oil-fired EGUs by the statutorily-mandated deadline, December 20, 2002, 2 years after such sources were listed under CAA section 112(c). The EPA settled that litigation. The consent decree resolving the case requires the EPA to sign a notice of proposed rulemaking setting forth the EPA's proposed CAA section 112(d) emission standards for coal- and oil-fired EGUs by March 16, 2011, and a notice of final rulemaking by December 16, 2011.[8]

C. What is the relationship between this final rule and other combustion rules?

1. CAA Section 111

The EPA promulgated revised NSPS for SO_2, nitrogen oxides (NO_X), and PM under CAA section 111 for EGUs (40 CFR part 60, subpart Da) and industrial boilers (IB) (40 CFR part 60, subparts Db and Dc) on February 27, 2006 (71 FR 9866). As noted elsewhere, in this action we are finalizing certain amendments to 40 CFR part 60, subpart Da. In developing this final rule, we considered the monitoring, testing, and recordkeeping requirements of the existing and revised NSPS to avoid duplicating requirements to the extent possible.

2. CAA Section 112

The EPA has previously developed other non-EGU combustion-related NESHAP under CAA section 112(d). The EPA promulgated final NESHAP for major source industrial, commercial and institutional boilers and process heaters (IB) and area source industrial, commercial and institutional boilers on March 21, 2011 (40 CFR part 63, subpart DDDDD, 76 FR 15608; and subpart JJJJJJ, 76 FR 15249, respectively), and promulgated standards for stationary combustion turbines (CT) on March 5, 2004 (40 CFR part 63 subpart YYYY; 69 FR 10512). In addition to these three NESHAP, on March 21, 2011, the EPA also promulgated final CAA section 129 standards for commercial and institutional solid waste incineration (CISWI) units, including energy recovery units (40 CFR part 60, subparts CCCC (NSPS) and DDDD (emission guidelines); 76 FR 15704); and a definition of non-hazardous secondary materials that are solid waste (Non-hazardous Solid Waste Definition Rule (40 CFR part 241, subpart B; 76 FR 15456)). Electric generating units and IB

[6] In CAMR and the 2005 Action, EPA interpreted section 111(d) of the Act as prohibiting the Agency from establishing an existing source standard of performance under CAA section 111(d) for any HAP emitted from a particular source category, if the source category is regulated under CAA section 112.

[7] American Nurses Association, Chesapeake Bay Foundation, Inc., Conservation Law Foundation, Environment America, Environmental Defense Fund, Izaak Walton League of America, Natural Resources Council of Maine, Natural Resources Defense Council, Physicians for Social Responsibility, Sierra Club, The Ohio Environmental Council, and Waterkeeper Alliance, Inc. (Civ. No. 1:08–cv–02198 (RMC)).

[8] The consent decree originally required EPA to sign a notice of final rulemaking no later than November 16, 2011; however, on October 21, 2011, pursuant to paragraph 6 of the consent decree, the parties agreed to a 30-day extension of the final rule deadline. As stated in the stipulation memorializing the extension, the parties agreed to the extension of 30 days because EPA provided an additional 30 days for public comment and the time was necessary to respond to comments submitted on the proposed rule.

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that combust fossil fuel and solid waste, as that term is defined by the Administrator pursuant to the Resource Conservation and Recovery Act (RCRA), *see* 76 FR 15456, will be subject to standards issued pursuant to CAA section 129 (*e.g.*, CISWI), unless they meet one of the exemptions in CAA section 129(g)(1). Clean Air Act section 129 standards are discussed in more detail below.

The two IB (Boiler) NESHAP, the CT NESHAP, and this final rule will regulate HAP emissions from sources that combust fossil fuels for electrical power, process operations, or heating. The differences among these rules are due to the size of the units (megawatt (MW), megawatt-electric (MWe), or British thermal unit per hour (Btu/hr)), the boiler/furnace technology, and/or the portion of their electrical output (if any) for sale to any utility power distribution systems.

Pursuant to the CAA, an EGU is "any fossil fuel fired combustion unit of more than 25 megawatts that serves a generator that produces electricity for sale. A unit that cogenerates steam and electricity and supplies more than one-third of its potential electric output capacity and more than 25 megawatts electrical output to any utility power distribution system for sale shall be considered an electric utility steam generating unit." CAA section 112(a)(8). We consider all of the MW ratings quoted in the final rule to be the original rated nameplate capacity of the unit. We consider cogeneration to be the simultaneous production of power (electricity) and another form of useful thermal energy (usually steam or hot water) from a single fuel-consuming process.

We consider any combustion unit, regardless of size, that produces steam to serve a generator that produces electricity exclusively for industrial, commercial, or institutional purposes (*i.e.*, makes no sales to the national electrical distribution grid) to be an IB unit. We do not consider a fossil fuel-fired combustion unit that serves a generator that produces electricity for sale to be an EGU under the final rule if the size of the combustion unit is less than or equal to 25 MW. Units that are 25 MW or less are likely subject to one of the two Boiler NESHAP.

Because of the combustion technology of simple-cycle and combined-cycle stationary CTs (with the exception of integrated gasification combined cycle (IGCC) units that burn gasified coal or petroleum coke synthesis gas/syngas), we do not consider these CTs to be EGUs for purposes of this final rule.[9]

The December 2000 listing discussed above did not list natural gas-fired EGUs. Thus, this final rule does not regulate a unit that otherwise meets the CAA section 112(a)(8) definition of an EGU but that combusts natural gas exclusively or natural gas in combination with another fossil fuel where the natural gas constitutes 90.0 percent or more of the average annual heat input during any 3 consecutive calendar years or 85.0 percent or more of the annual heat input in one calendar year. We consider such units to be natural gas-fired EGUs notwithstanding the combustion of some coal or oil (or derivative thereof) and such units are not subject to this final rule.

The CAA does not define the terms "fossil fuel-fired" and "fossil fuel." In this rule, we are finalizing definitions for both terms for purposes of this rule. The definition of "fossil fuel-fired" will help determine the applicability of the final rule to combustion units that sell electricity to the utility power distribution system. The definition of "fossil fuel-fired" establishes the amount of fossil fuel combustion necessary to make a unit "fossil fuel-fired" and hence potentially subject to this final rule. These definitions will help determine applicability of the final rule to units that primarily fire non-fossil fuels (*e.g.*, biomass) but generally start up using either natural gas or distillate oil and may use these fuels (or coal) during normal operation for flame stabilization.

In addition, the EPA is finalizing in the definition of "fossil fuel-fired" that, among other things, an EGU must fire coal or oil for more than 10.0 percent of the average annual heat input during any 3 consecutive calendar years or for more than 15.0 percent of the annual heat input during any one calendar year after the applicable compliance date in order to be considered a fossil fuel-fired EGU subject to this final rule. The EPA has based these threshold percentage values on the definition of "oil-fired" in the Acid Rain Program (ARP) found at 40 CFR 72.2. Though the EPA does not have annual heat input data for, for example, biomass co-fired EGUs because their use is not yet commonplace, we believe this definition accounts for the use of fossil fuels for flame stabilization use without inappropriately subjecting such units to this final rule.

[9] The CT NESHAP regulates HAP emissions from all simple-cycle and combined-cycle stationary CTs producing electricity or steam for any purpose.

Units that do not meet the EGU definition will in most cases be considered IB units subject to one of the two Boiler NESHAP. Thus, for example, a biomass-fired EGU, regardless of size, that utilizes fossil fuels for startup and flame stabilization purposes only (*i.e.*, less than or equal to 10.0 percent of the average annual heat input in any 3 consecutive calendar years or less than or equal to 15.0 percent of the annual heat input during any one calendar year) is not considered to be a fossil fuel-fired EGU under this final rule.

A cogeneration facility that sells electricity to any utility power distribution system equal to more than one-third of its potential electric output capacity and more than 25 MW will be considered an EGU if the facility is fossil fuel-fired as that term is defined in the final rule.

We recognize that different CAA section 112 rules may impact a particular unit at different times. For example, the Boiler NESHAP may cover some cogeneration units. Such a unit may decide to increase or decrease the proportion of production output it supplies to the electric utility grid, thus causing the unit to meet the EGU cogeneration criteria (*i.e.*, greater than one-third of its potential output capacity and greater than 25 MW). A unit subject to one of the Boiler NESHAP that increases its electricity output and meets the definition of an EGU would be subject to the final EGU NESHAP.

Another rule intersection may occur where one or more coal- or oil-fired EGU(s) share an air pollution control device (APCD) and/or an exhaust stack with one or more similarly-fueled IB unit(s). To demonstrate compliance with two different rules, either the emissions would need to be apportioned to the appropriate source or the more stringent emission limit would need to be met. Data needed to apportion emissions are not currently required by this final rule or the final boiler NESHAP and are not otherwise available. Therefore, the EPA is finalizing the requirement to comply with the more stringent emission limit.

3. CAA Section 129

Clean Air Act section 129 regulates units that combust "non-hazardous secondary materials," as that term is defined by the Administrator under the Resource Conservation and Recovery Act (RCRA), that are "solid wastes." On March 21, 2011, the EPA promulgated the final Non-Hazardous Solid Waste Definition Rule (76 FR 15456). Any EGU that combusts any solid waste as defined in that final rule is a solid waste

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incineration unit subject to emissions standards under CAA section 129.

In the Non-Hazardous Solid Waste Definition Rule, the EPA determined that coal refuse from current mining operations is not considered to be a "solid waste" if it is not discarded. Coal refuse that is in legacy coal refuse piles is considered a "solid waste" because it has been discarded. However, if discarded coal refuse is processed in the same manner as currently mined coal refuse, the coal refuse would not be considered a solid waste but instead would be considered a product fossil fuel. Therefore, the combustion of such material by a combustion unit would not subject that unit to regulation under CAA section 129. Instead, the unit would be subject to this final rule if it meets the definition of EGU. In the proposed rule, we assumed that all units that combust coal refuse and otherwise meet the definition of a coal-fired EGU are in fact combusting newly mined coal refuse or coal refuse from legacy piles that has been processed such that it is not a solid waste. We did not receive any information since proposal that would cause us to revise this determination in the final rule.

Further, CAA section 129(g)(1)(B) exempts from regulation

> "* * * qualifying small power production facilities, as defined in section 796(17)(C) of Title 16, or qualifying cogeneration facilities, as defined in section 796(18)(B) of Title 16, which burn homogeneous waste * * * for the production of electric energy or in the case of qualifying cogeneration facilities which burn homogeneous waste for the production of electric energy and steam or forms of useful energy (such as heat) which are used for industrial, commercial, heating or cooling purposes * * *"

If the "homogeneous waste" material that such facilities combust is also a fossil fuel, and those facilities otherwise meet the definition of an EGU under CAA section 112(a)(8), then those facilities are exempt from regulation under CAA section 129 but covered under this final rule. For example, a qualifying small power production facility or cogeneration facility combusting only coal refuse that is a solid waste and a "homogenous waste," as that term is defined in the final CAA section 129 CISWI standards, would be subject to this final rule if the unit also met the definition of EGU.

D. What are the health effects of pollutants emitted from coal- and oil-fired EGUs?

This final rule protects air quality and promotes public health by reducing emissions of some of the HAP listed in CAA section 112(b)(1). Utilities are by far the largest anthropogenic source of Hg in the U.S. In addition, EGUs are the largest source of HCl, hydrogen fluoride (HF), and selenium (Se) emissions, and a major source of metallic HAP emissions including As, chromium (Cr), Ni, and others. The discrepancy is even greater now that almost all other major source categories have been required to control Hg and other HAP under CAA section 112. In 2005, U.S. EGUs emitted 50 percent of total domestic anthropogenic Hg emissions, 62 percent of total As emissions, 39 percent of total cadmium (Cd) emissions, 22 percent of total Cr emissions, 82 percent of total HCl emissions, 62 percent of total HF emissions, 28 percent of total Ni emissions, and 83 percent of total Se emissions.[10] Exposure to these HAP, depending on exposure duration and levels of exposures, is associated with a variety of adverse health effects. These adverse health effects may include chronic health disorders (*e.g.*, irritation of the lung, skin, and mucus membranes; detrimental effects on the central nervous system; damage to the kidneys; and alimentary effects such as nausea and vomiting). Two of the HAP are classified as human carcinogens (As and CrVI) and two as probable human carcinogens (Cd and Ni). *See* 76 FR 25003–25005 for a fuller discussion of the health effects associated with these pollutants.

III. Appropriate and Necessary Finding

A. Overview

In December 2000, the EPA issued a finding pursuant to CAA section 112(n)(1)(A) that it was appropriate and necessary to regulate coal- and oil-fired EGUs under CAA section 112 and added such units to the list of source categories subject to regulation under section 112(d). The EPA found that it was appropriate to regulate HAP emissions from coal- and oil-fired EGUs because, among other reasons, Hg is a hazard to public health, and U.S. EGUs are the largest domestic source of Hg emissions. The EPA also found it appropriate to regulate HAP emissions from EGUs because it had identified certain control options that would effectively reduce HAP emissions from U.S. EGUs. The EPA found that it was necessary to regulate HAP emissions from U.S. EGUs under section 112 because the implementation of other requirements under the CAA will not adequately address the serious public health and environmental hazards arising from HAP emissions from U.S. EGUs and that CAA section 112 is intended to address HAP emissions. *See* 76 FR 24984–20985 (for further discussion of 2000 finding).

Because several years had passed since the 2000 finding, the EPA performed additional technical analyses for the proposed rule, even though those analyses were not required. These analyses included a national-scale Hg risk assessment focused on populations with high levels of self-caught fish consumption, and a set of 16 case studies of inhalation cancer risks for non-Hg HAP. The analyses confirm that it remains appropriate and necessary to regulate U.S. EGUs under section 112.

In the preamble to the proposed rule, the EPA reported the results of those additional technical analyses. Those analyses confirmed the 2000 finding that it is appropriate to regulate U.S. EGUs under section 112 by demonstrating that (1) Hg continues to pose a hazard to public health because up to 28 percent of watersheds were estimated to have Hg deposition attributable to U.S. EGUs that contributes to potential exposures above the reference dose for methylmercury (MeHg RfD), a level above which there is increased risk of neurological effects in children, (2) non-Hg HAP emissions pose a hazard to public health because case studies at 16 facilities demonstrated that lifetime cancer risks at 4 of the facilities exceed 1 in 1 million, and (3) U.S. EGUs remain the largest domestic source of Hg emissions and several HAP (*e.g.*, HF, Se, HCl), and are among the largest contributors for other HAP (*e.g.*, As, Cr, Ni, HCN). Thus, in the preamble to the proposed rule, the EPA found that Hg and non-Hg HAP emissions from U.S. EGUs pose hazards to public health, which confirmed the 2000 finding and demonstrated that it remains appropriate to regulate U.S. EGUs under section 112.

In the preamble to the proposed rule, the EPA also found that it is appropriate to regulate U.S. EGUs because (1) Hg emissions pose a hazard to the environment and wildlife, adversely impacting species of fish-eating birds and mammals, (2) acid gas HAP pose a hazard to the environment because they contribute to aquatic acidification, and (3) effective controls are available to reduce Hg and non-Hg HAP emissions from U.S. EGUs.

The additional analyses reported in the preamble to the proposed rule also confirmed that it remains necessary to regulate U.S. EGU under CAA section 112. These analyses demonstrated that (1) Hg emissions from U.S. EGUs remaining in 2016 are reasonably anticipated to pose a hazard to public health after imposition of other CAA

[10] From 2005 National-Scale Air Toxics Assessment (NATA), available at *http://www.epa.gov/ttn/atw/nata2005/.*

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requirements, such as the Cross-State Air Pollution Rule (CSAPR); (2) U.S. EGUs are reasonably anticipated to remain the largest source of Hg in the U.S. and thus contribute to the risk associated with exposure to MeHg; (3) Hg emissions from U.S. EGUs after imposition of the requirements of the CAA were projected to be 29 tons per year in 2016, similar to levels of Hg emitted today, indicating that further substantial reductions in Hg emissions are not reasonably anticipated without federal regulations on Hg from U.S. EGUs; (4) we cannot be certain that the identified cancer risks attributable to non-Hg emissions from U.S. EGUs will be addressed through imposition of the requirements of the CAA because companies can use compliance strategies for criteria pollutants that do not achieve HAP co-benefits (*e.g.*, purchasing allowances in a trading program); and (5) we cannot ensure that Hg and non-Hg HAP emissions reductions achieved since 2005 would be permanent without federally binding regulations for Hg from U.S. EGUs.

Since issuance of the proposed rule, the EPA has conducted peer reviews of the national-scale Hg risk assessment (Hg Risk TSD) and the approach for estimating chromium and nickel inhalation cancer risk in the case studies.[11] [12] The peer review of the Hg Risk TSD was conducted by EPA's independent Science Advisory Board (SAB). The SAB stated that it "supports the overall design of and approach to the risk assessment and finds that it should provide an objective, reasonable, and credible determination of the potential for a public health hazard from mercury emitted from U.S. EGUs."[13] SAB recommended several improvements to the data, methods and documentation of the analyses, which EPA has fully addressed in the revised Hg Risk TSD.

As described in the revised Hg Risk TSD, after addressing comments from the peer review, the revised results show that up to 29 percent of modeled watersheds are estimated to have Hg deposition attributable to U.S. EGUs that contributes to potential exposures above the MeHg RfD, an increase of one percentage point from the results reported in the proposed rule. We conclude that Hg emissions from EGUs pose a hazard to public health based on the total of 29 percent of modeled watersheds at risk. Our analyses show that of the 29 percent of watersheds with population at-risk, in 10 percent of those watersheds U.S. EGU deposition alone without considering deposition from other sources would lead to potential exposures that exceed the MeHg RfD, and in 24 percent of those watersheds, total potential exposures to MeHg exceed the RfD and U.S. EGUs contribute at least 5 percent to Hg deposition.[14] [15] Each of these results independently supports our conclusion that Hg emissions from EGUs pose hazards to public health.

The peer review of the approach to estimate Ni and Cr cancer risk in the case studies also supported EPA's assessment. The EPA enhanced this analysis in response to the peer review and public comments. The results of those revised analyses show that 6 of 16 modeled facilities have lifetime cancer risks greater than 1 in a million, thus confirming that non-Hg HAP emissions from U.S. EGUs remain a hazard to public health. Given Congress' determination that categories of sources that emit HAP resulting in a lifetime cancer risk greater than 1 in a million should not be removed from the CAA section 112(c) source category list and should continue to be regulated under CAA section 112, the EPA concludes that risk above that level represents a hazard to public health.

Based on our consideration of the peer reviews, public comments, and our updated analyses, we confirm the findings that Hg and non-Hg HAP emissions from U.S. EGUs pose hazards to public health and that it remains appropriate to regulate U.S. EGUs under CAA section 112. We also conclude that it remains appropriate to regulate U.S. EGUs under CAA section 112 because of the magnitude of Hg and non-Hg emissions, environmental effects of Hg and certain non-Hg emissions, and the availability of controls to reduce HAP emissions from EGUs.

In addition, we conclude that the hazards to public health from Hg and non-Hg emissions from U.S. EGUs are reasonably anticipated to remain after imposition of the requirements of the CAA. The same is true for hazards to the environment. Thus, we confirm that it is necessary to regulate U.S. EGUs under CAA section 112.

B. Peer Review of the Hg Risk TSD Supporting the Appropriate and Necessary Finding for Coal and Oil-Fired EGUs and EPA Response

In the preamble to the proposed rule, the EPA stated that "in making the finding that it remains appropriate and necessary to regulate EGUs to address public health and environmental hazards associated with emissions of Hg and Non-Hg HAP from EGUs, the EPA determined that the Hg Risk TSD supporting EPA's 2011 review of U.S. EGU health impacts should be peer-reviewed."[16] We also indicated that due to the court-ordered schedule for the final rule, we planned to conduct the peer review as expeditiously as possible after issuance of the proposed rule, and that the results of the peer review and any EPA response would be published before the final rule. Due to the extension of the public comment period and the volume of public comments received on the analyses supporting the proposed rule, we were unable to publish EPA's response prior to signature of the final rule.

The EPA's response to the peer review the Hg Risk TSD is fully documented in the revised *Technical Support Document (TSD): National-Scale Assessment of Hg Risk to Populations of High Consumption of Self-Caught Fish In Support of the Appropriate and Necessary Finding for Coal and Oil-Fired Electric Generating Units.*[17] The following sections describe the peer review process that we followed, provide the peer review charge questions presented to the peer review panel, summarize the key recommendations from the peer review, and summarize our responses to those recommendations.

[11] U.S. EPA. 2011a. *National-Scale Assessment of Mercury Risk to Populations with High Consumption of Self-caught Freshwater Fish In Support of the Appropriate and Necessary Finding for Coal- and Oil-Fired Electric Generating Units.* Office of Air Quality Planning and Standards. November. EPA–452/R–11–009.

[12] U.S. EPA. 2011b. *Supplement to Nan-mercury Case Study Chronic Inhalation Risk Assessment for the Utility MACT Appropriate and Necessary Analysis.* Office of Air Quality Planning and Standards. November.

[13] U.S. Environmental Protection Agency-Science Advisory Board (U.S. EPA–SAB). 2011. Peer Review of EPA's Draft National-Scale Mercury Risk Assessment. EPA–SAB–11–017. September. Available on the Internet at *http://yosemite.epa.gov/sab/sabproduct.nsf/BCA23C5B7917F5BF8525791A0072CCA1/$File/EPA-SAB-11-017-unsigned.pdf.*

[14] Because some watersheds with exposures sufficient to exceed the RfD with Hg deposition from U.S. EGUs alone without considering deposition from other sources also have U.S. EGU contributions of more than 5 percent of total Hg deposition, there is some overlap between the two risk metrics. This explains why the total percent of watersheds exceeding either risk metric is less than the sum of the individual risk metrics.

[15] Requiring at least a 5 percent EGU contribution is a conservative approach given the increasing risks associated with incremental exposures above the RfD. Because we are finding 24 percent of watersheds with populations potentially at risk even using this conservative approach, we have confidence that emissions of Hg from U.S. EGUs are causing a hazard to public health.

[16] 76 FR 25012.

[17] U.S. EPA, 2011a.

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1. Summary of Peer Review Process

Peer review is consistent with EPA's open and transparent process to ensure that the Agency's scientific assessments and rulemakings are based on the best science available. This regulatory action was supported by the Hg Risk TSD, which is a highly influential scientific assessment. Therefore, the EPA conducted a peer review in accordance with OMB's *Final Information Quality Bulletin for Peer Review*[18] as described below. All the materials related to the peer review, including the SAB's final report, can be found in the docket for this rulemaking.

The EPA commissioned the peer review through EPA's SAB, which provides independent advice and peer review to EPA's Administrator on the scientific and technical aspects of environmental issues. The SAB convened a 22-member peer review committee. The SAB process for selecting the panel began with two **Federal Register** Notices requesting nominations for the *Mercury Review Panel*.[19] Based on nominations received, a list of potential panel members, along with bio-sketches, was posted for public comment on the SAB Web site on April 15, 2011. The members of the *Mercury Review Panel* were announced on May 24, 2011. The membership of the panel included representatives of 16 academic institutions, 4 state health or environmental agencies, 1 federal agency, and 1 utility industry organization.[20] The panel held a public meeting in Research Triangle Park, NC, on June 15–17, 2011, which included the opportunity for public comment on the Hg Risk TSD and the peer review process.[21] At the June 15–17 public meeting, the panel completed a draft peer review report. The minutes of that meeting and the draft peer review report were posted to the SAB public Web site within the public comment period for the proposed rule. The panel discussed the draft report at a public teleconference on July 12, 2011, during which additional opportunities for public comment were provided,[22] and submitted a revised draft for quality review by the Chartered SAB before the end of the public comment period on the rule. The Chartered SAB held a public teleconference on September 7, 2011, to conduct a quality review of the draft report; this teleconference also included a final opportunity for public comment.[23] The SAB submitted its final report to EPA on September 29, 2011.[24] Notice of all the meetings was published in the **Federal Register** and all of the materials discussed at the SAB meetings, including technical documents, presentations, meeting minutes, and draft reports were posted for public access on the SAB Web site[25] and were added to the docket for the final rule on October 14, 2011.

2. Peer Review Charge Questions

The EPA asked the SAB to comment on the Hg Risk TSD, including the overall design and approach and the use of specific models and key assumptions. The EPA also asked the SAB to comment on the extent to which specific facets of the assessment were well characterized in the Hg Risk TSD. The specific charge questions are listed below:

Question 1. Please comment on the scientific credibility of the overall design of the mercury risk assessment as an approach to characterize human health exposure and risk associated with U.S. EGU mercury emissions (with a focus on those more highly exposed).

Question 2. Are there any additional critical health endpoint(s) besides IQ loss, which could be quantitatively estimated with a reasonable degree of confidence to supplement the mercury risk assessment (*see* section 1.2 of the Mercury Risk TSD for an overview of the risk metrics used in the risk assessment)?

Question 3. Please comment on the benchmark used for identifying a potentially significant public health impact in the context of interpreting the IQ loss risk metric (i.e., an IQ loss of 1 to 2 points or more representing a potential public health hazard). Is there any scientifically credible alternate decrement in IQ that should be considered as a benchmark to guide interpretation of the IQ risk estimates (*see* section 1.2 of the Mercury Risk TSD for additional detail on the benchmark used for interpreting the IQ loss estimates)?

Question 4: Please comment on the spatial scale used in defining watersheds that formed the basis for risk estimates generated for the analysis (i.e., use of 12-digit hydrologic unit code classification). To what extent do [Hydrologic Unit Code] HUC12 watersheds capture the appropriate level of spatial resolution in the relationship between changes in mercury deposition and changes in MeHg fish tissue levels? (see section 1.3 and Appendix A of the Mercury Risk TSD for additional detail on specifying the spatial scale of watersheds used in the analysis).

Question 5: Please comment on the extent to which the fish tissue data used as the basis for the risk assessment are appropriate and sufficient given the goals of the analysis. Please comment on the extent to which focusing on data from the period after 1999 increases confidence that the fish tissue data used are more likely to reflect more contemporaneous patterns of Hg deposition and less likely to reflect earlier patterns of Hg deposition. Are there any additional sources of fish tissue MeHg data that would be appropriate for inclusion in the risk assessment?

Question 6: Given the stated goal of estimating potential risks to highly exposed populations, please comment on the use of the 75th percentile fish tissue MeHg value (reflecting targeting of larger but not the largest fish for subsistence consumption) as the basis for estimating risk at each watershed. Are there scientifically credible alternatives to use of the 75th percentile in representing potential population exposures at the watershed level?

Question 7: Please comment on the extent to which characterization of consumption rates and the potential location for fishing activity for high-end self-caught fish consuming populations modeled in the analysis are supported by the available study data cited in the Mercury Risk TSD. In addition, please comment on the extent to which consumption rates documented in Section 1.3 and in Appendix C of the Mercury Risk TSD provide appropriate representation of high-end fish consumption by the subsistence population scenarios used in modeling exposures and risk. Are there additional data on consumption behavior in subsistence populations active at inland freshwater water bodies within the continental U.S.?

Question 8: Please comment on the approach used in the risk assessment of

[18] Office of Management and Budget (OMB). 2004. *Final Information Quality Bulletin for Peer Review.* December. Available on the Internet at *http://www.whitehouse.gov/omb/memoranda_fy2005_m05-03.*

[19] 76 FR 10896 and 76 FR 17649. The first notice requested nominations to a Clean Air Scientific Advisory Committee (CASAC) panel. Upon review of the scope of the CASAC charter (resulting from a public comment received in response to the first notice), the SAB determined that it would be more appropriate to form a panel under the SAB, rather than CASAC. The second notice announced this change and requested nominations for the SAB panel.

[20] The full list of panel members is documented at *http://yosemite.epa.gov/sab/sabproduct.nsf/0/9F048172004D93BB8525783900503486/$File/Determination%20memo%20with%20addendum-05.24.11.pdf.*

[21] 76 FR 29746.

[22] 76 FR 39102.

[23] 76 FR 50729.

[24] U.S. EPA–SAB, 2011. Peer Review of EPA's Draft National-Scale Mercury Risk Assessment.

[25] *See http://yosemite.epa.gov/sab/sabpeople.nsf/WebCommittees/BOARD.*

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assuming that a high-end fish consuming population could be active at a watershed if the "source population" for that fishing population is associated with that watershed (e.g., at least 25 individuals of that population are present in a U.S. Census tract intersecting that watershed). Please identify any additional alternative approaches for identifying the potential for population exposures in watersheds and the strengths and limitations associated with these alternative approaches (additional detail on how EPA assessed where specific high-consuming fisher populations might be active is provided in section 1.3 and Appendix C of the Mercury Risk TSD).

Question 9: Please comment on the draft risk assessment's characterization of the limitations and uncertainty associated with application of the Mercury Maps approach (including the assumption of proportionality between changes in mercury deposition over watersheds and associated changes in fish tissue MeHg levels) in the risk assessment. Please comment on how the output of CMAQ [Community Multiscale Air Quality] modeling has been integrated into the analysis to estimate changes in fish tissue MeHg levels and in the exposures and risks associated with the EGU-related fish tissue MeHg fraction (*e.g.,* matching of spatial and temporal resolution between CMAQ modeling and HUC12 watersheds). Given the national scale of the analysis, are there recommended alternatives to the Mercury Maps approach that could have been used to link modeled estimates of mercury deposition to monitored MeHg fish tissue levels for all the watersheds evaluated? (additional detail on the Mercury Maps approach and its application in the risk assessment is presented in section 1.3 and Appendix E of the Mercury Risk TSD).

Question 10: Please comment on the EPA's approach of excluding watersheds with significant non-air loadings of mercury as a method to reduce uncertainty associated with application of the Mercury Maps approach. Are there additional criteria that should be considered in including or excluding watersheds?

Question 11: Please comment on the specification of the concentration-response function used in modeling IQ loss. Please comment on whether EPA, as part of uncertainty characterization, should consider alternative concentration-response functions in addition to the model used in the risk assessment. Please comment on the extent to which available data and methods support a quantitative treatment of the potential masking effect of fish nutrients (*e.g.,* omega-3 fatty acids and selenium) on the adverse neurological effects associated with mercury exposure, including IQ loss (detail on the concentration-response function used in modeling IQ loss can be found in section 1.3 of the Mercury Risk TSD).

Question 12: Please comment on the degree to which key sources of uncertainty and variability associated with the risk assessment have been identified and the degree to which they are sufficiently characterized.

Question 13: Please comment on the draft Mercury Risk TSD's discussion of analytical results for each component of the analysis. For each of the components below, please comment on the extent to which EPA's observations are supported by the analytical results presented and whether there is a sufficient characterization of uncertainty, variability, and data limitations, taking into account the models and data used: Mercury deposition from U.S. EGUs, fish tissue MeHg concentrations, patterns of Hg deposition with HG fish tissue data, percentile risk estimates, and number and frequency of watersheds with populations potentially at risk due to U.S. EGU mercury emissions.

Question 14: Please comment on the degree to which the final summary of key observations in Section 2.8 is supported by the analytical results presented. In addition, please comment on the degree to which the level of confidence and precision in the overall analysis is sufficient to support use of the risk characterization framework described on page 18.

3. Summary of Peer Review Findings and Recommendations

The SAB was generally supportive of EPA's approach.[26] The SAB concluded, "[i]n summary, based on its review of the draft Technical Support Document and additional information provided by EPA representatives during the public meetings, the SAB supports the overall design of and approach to the risk assessment and finds that it should provide an objective, reasonable, and credible determination of the potential for a public health hazard from mercury emitted from U.S. EGUs."[27] The SAB further concluded, "[t]he SAB regards the design of the risk assessment as suitable for its intended purpose, to inform decision-making regarding an 'appropriate and necessary finding' for regulation of hazardous air pollutants from coal and oil-fired EGUs, provided that our recommendations are fully considered in the revision of the assessment."[28]

The SAB report contained many recommendations for improving the Hg Risk TSD, which the SAB organized into three general themes: (1) Improve the clarity of the Hg Risk TSD regarding methods and presentation of results, (2) expand the discussion of sources of variability and uncertainty, and (3) de-emphasize IQ loss as an endpoint. In the following subsection, we provide EPA's response to these recommendations.

4. The EPA's Responses to Peer Review Recommendations

In response to the peer review, the EPA has substantially revised the Hg Risk TSD. The revised Hg Risk TSD addresses all of the recommendations from the SAB and includes a detailed list of the specific revisions made to the Hg Risk TSD. Revisions in response to the main recommendations are summarized below. Italicized statements are the SAB's recommendations, which are followed by EPA's response.

- *The watershed-focus of the Hg Risk TSD should be clearly stated early in the introduction to the document.* We have stated clearly in the introduction to the revised Hg Risk TSD that the focus of the analysis is on scenarios of high fish consumption by subsistence level fishing populations, assessed at watersheds where there is the potential for such subsistence fishing activity. Specifically, we modeled risk for a set of subsistence fisher scenarios at those watersheds where (a) we have measured fish tissue Hg data and (b) it is reasonable to assume that subsistence-level fishing activity could occur. We emphasize the point that the analysis is not a representative population-weighted assessment of risk. Rather, it is based on evaluating these potential exposure scenarios.
- *Because IQ does not fully capture the range of neurodevelopmental effects associated with Hg exposure, analysis of this endpoint should be deemphasized (and moved to an appendix) and primary focus should be placed on the MeHg RfD-based hazard quotient metric.* We modified the structure of the revised Hg Risk TSD accordingly.
- *Clarify the rationale for using a Hazard Quotient (HQ) at or above 1.5 as the basis for selecting potentially impacted watersheds.* The SAB fully supported using HQ as the risk metric, but we revised the discussion in the Hg Risk TSD to clarify why we selected 1.5

[26] U.S. EPA–SAB, 2011.

[27] *Id.*

[28] *Id.*

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as the benchmark. We clarified that exposures above the RfD (*i.e.,* an HQ above one) represent increasing risk of neurological health effects.[29] We further clarified that the HQ is calculated to only one significant digit, based on the precision in the underlying RfD calculations. As a result, rounding convention requires that any values at or above 1.5 be expressed as an HQ of 2, while any values below 1.5 (*e.g.,* 1.49) be rounded to an HQ of 1. Thus, MeHg exposures leading to an HQ at or above 1.5 for pregnant women are considered above the RfD and are associated with increased risk of neurological health effects in children born to those mothers.

• *Regarding the fish tissue dataset used in the Hg Risk TSD, clarify which species of Hg is reflected in the underlying samples and discuss the implications of differences across states in sampling protocols in introducing bias into the analysis.* We clarified that in most cases, the fish tissue is measured for total Hg. Furthermore, based on the scientific literature,[30] it is reasonable to assume that more than 90 percent of fish tissue Hg is MeHg. Therefore, we incorporated an Hg conversion factor[31] into our exposure calculations to account for the fraction of total Hg that is MeHg in fish. We also expanded the discussion of uncertainty to address the potential for different sampling protocols across states to introduce bias into the Hg Risk TSD.

• *Additional detail should be provided on the characteristics of the fish tissue Hg dataset, including its derivation and the distribution of specific attributes across the dataset (e.g., number of fish tissue samples and number of different waterbodies in a watershed, number of species reflected across watersheds).* We included additional figures and tables describing the derivation of the watershed-level fish tissue Hg dataset, including the filtering steps applied to the original water body level data and the additional steps taken to generate the watershed-level fish tissue Hg percentile estimates. In addition, we included tables summarizing key attributes of the dataset (*e.g.,* distribution of fish tissue sample size and number of species across the watershed-level estimates).

• *Determine whether there is additional (more recent) fish tissue data for key states including Pennsylvania, New Jersey, Kentucky and Illinois where U.S. EGUs Hg deposition may be more significant.* We expanded the fish tissue dataset by incorporating additional fish tissue data from the National Listing of Fish Advisories (NLFA), which included additional data for four states (MI, NJ, PA, and MN). We also obtained additional data for Wisconsin. These additional data expanded the number of watersheds in the analysis from 2,317 to 3,141, an increase of 36 percent. The additional watersheds improve coverage in areas with high levels of U.S. EGU-attributable Hg deposition, and thus increase our confidence in the overall results of the Hg Risk TSD.

• *Include additional discussion of the potential that the low sampling rates reflected across many of the watersheds may low-bias the 75th percentile fish tissue Hg estimates used in estimating potential exposures. In addition, include a sensitivity analysis using the 50th percentile estimates to provide a bound on the risk.* The SAB expressed support for the use of the 75th percentile fish tissue Hg value in the Hg Risk TSD, while recommending additional discussion of the issue. We provided additional description of the fish tissue dataset, including distribution of sample sizes and fish species across the watersheds, and an improved discussion of uncertainty and potential low bias resulting from estimation of the 75th percentile fish tissue levels. We also included a sensitivity analysis that used the 50th percentile watershed-level fish tissue Hg level. This sensitivity analysis showed that using the 50th percentile estimates resulted in a decrease in the number and percentage of modeled watersheds with populations potentially at-risk from U.S. EGU-attributable MeHg exposures, from 29 percent of watersheds exceeding either risk metric (*i.e.,* MeHg exposure from U.S. EGUs alone exceeds the RfD or total MeHg exposure exceeds the RfD and U.S. EGUs contribute at least 5 percent) in the revised Hg Risk TSD to 26 percent in the sensitivity analysis in the revised Hg Risk TSD.

• *Expand the discussion of caveats associated with the fish consumption rates used in the analysis.* The SAB was generally supportive of the consumption rates used, while recommending additional discussion of caveats. We expanded the discussion of uncertainty related to the fish consumption rates to address the caveats identified by the SAB. The uncertainty discussion now explains (1) that high-end consumption rates for South Carolina reflect small sample sizes, and therefore may be more uncertain, (2) that the consumption surveys underlying the studies are older (*i.e.,* mostly based on survey data from the 1990s) and behavior may have changed (*i.e.,* consumption rates may have changed since the surveys were conducted), and (3) that consumption rates used in the Hg Risk TSD are annualized rather than seasonal rates and thus contribute little to overall uncertainty. None of these sources of uncertainty is associated with a particular directional bias (*e.g.,* neither systematically higher nor lower risk).

• *Verify whether the consumption rates are daily values expressed as annual averages and whether they are "as caught" or "as prepared."* We carefully reviewed the studies underlying the fish consumption rates used in the Hg Risk TSD and verified that the rates are annual averages of the daily consumption rates and that they represent as prepared estimates. We also expanded the explanation of the exposure calculations to describe more completely the exposure factors and equation used to generate the average daily MeHg intake estimates for the subsistence scenarios.

• *Explain the criteria for exclusion of fish less than 7 inches in length from analysis.* We provided the rationale for the 7-inch cutoff for edible fish used in the Hg Risk TSD. Seven inches represents a minimum size limit for a number of key edible freshwater fish species established at the state level. For example, Pennsylvania establishes 7 inches as the minimum size limit for both trout and salmon (other edible fish species such as bass, walleye and northern pike have higher minimum size limits). The impact of the 7-inch cutoff is likely to be quite small, as only 6 percent of potential fish samples were excluded due to this criterion.

• *Identify the number of watersheds excluded from the analysis due to the criterion for excluding watersheds with less than 25 members of a source population.* The SAB was generally supportive of the approach used for identifying watersheds with the potential for subsistence activity, while recommending additional information on the results of applying the approach. We added a figure to illustrate the number of watersheds with fish tissue Hg data used to model risk for each of the subsistence fishing scenarios. For all scenarios except the female subsistence fishing scenario, the exposure scenarios significantly limited the number of

[29] As stated in the preamble to the proposal, based on the current literature, exposures above the RfD contribute to risk of adverse effects.

[30] See the literature summary in Chapter 4 of U.S. EPA. 2000. *Guidance for Assessing Chemical Contaminant Data for Use in Fish Advisories.* Office of Science and Technology, Office of Water, Washington, DC EPA 823–B–00–007.

[31] In the Hg Risk TSD accompanying the proposed rule, we assumed that 100 percent of Hg in fish was MeHg. We derived the 0.95 conversion factor for the revised Hg Risk TSD to reflect that most studies show that more than 90 percent of total Hg in fish is MeHg. See Chapter 4 of U.S. EPA, 2000.

watersheds. Because the female subsistence fishing scenario does not differentiate with regard to ethnicity or socio-economic status (SES), we applied this scenario to all regions of the country and to all watersheds with fish tissue Hg data. This reflects our assumption that, given the generalized nature of the female subsistence fishing scenario, it is reasonable to assume that it could potentially occur at any watershed with fish tissue Hg data. The female subsistence fishing scenario included in the revised risk assessment is similar to the high-consuming female scenario included in the Hg Risk TSD.[32] However, the female subsistence fishing scenario is applied to all watersheds, while in the scenario for the high-consuming low-income female angler, we only evaluated watersheds with a population of at least 25 low-income females. The female subsistence fishing scenario provides greater coverage geographically than the high-consuming low-income female scenario. As described in the revised Hg Risk TSD, the EPA made this change in response to SAB's concerns regarding the potential exclusion of watersheds with fewer than 25 individuals and regarding coverage for high-end recreational fish consumption.[33]

• *Enhance the discussion of the assumption of a linear relationship between changes in Hg deposition and changes in fish tissue Hg at the watershed level, including providing citations to more recent studies supporting the proportional relationship between changes in Hg deposition and changes in MeHg fish tissue levels.* The SAB supported the assumption of a linear relationship between changes in Hg deposition and changes in fish tissue Hg at the watershed level, while recommending additional supporting language. We expanded our discussion of the scientific basis for the proportionality assumption and added citations for the more recent studies supporting the assumption. We also expanded the discussion of uncertainties associated with this assumption, including uncertainties related to the potential for sampled fish tissue Hg level to reflect previous Hg deposition, and the potential for non-air sources of Hg to contribute to sampled fish tissue Hg levels. Each of these sources of uncertainty may result in potential bias in the estimate of exposure associated with current deposition. If the fish tissue Hg levels are too high due to either previous Hg deposition or non-air sources of Hg, then the absolute level of exposure attributed to both total Hg deposition and U.S. EGU-attributable Hg deposition will be biased high. However, the percent contribution from U.S. EGUs will not be affected as it depends entirely on deposition. The EPA took steps to minimize the potential for these biases by (1) only using fish tissue Hg samples from after 1999, and (2) screening out watersheds that either contained active gold mines or had other substantial non-U.S. EGU anthropogenic emissions of Hg. The SAB concluded that the EPA's approach to minimizing the potential for these biases to affect the results of the Hg Risk TSD is sound. In addition, we conducted several sensitivity analyses to gauge the impact of excluding watersheds with the potential for non-EGU Hg loading. We found that the estimates of the percent of modeled watersheds with populations potentially at-risk were largely insensitive to these exclusions, suggesting that any potential biases from including watersheds with potential non-air Hg loadings are likely to be small.

• *Additional sources of variability should be discussed in terms of the degree to which they are reflected in the design of the risk assessment and the impact that they might have on risk estimates. These include: (1) The geographic patterns of populations of subsistence fishers, including how this factor interacts with the limited coverage we have for watersheds with our fish tissue Hg data, (2) the protocols used by states in collecting fish tissue Hg data, (3) body weights for subsistence fishing populations and the impact that this might have on exposure estimates, and (4) preparation and cooking methods which affect the conversion of fish tissue Hg levels (as measured) into "as consumed" values.* We expanded the discussion of sources of variability in the revised Hg Risk TSD to more fully address these sources of variability. The Hg Risk TSD quantitatively reflected many aspects of variability, including spatial and temporal variability in Hg emissions, Hg deposition, fish tissue Hg levels, and subsistence behavior. After evaluating the aspects of variability assessed qualitatively in the Hg Risk TSD such as temporal response in fish tissue, we do not believe that quantitatively incorporating any of these aspects would substantially change the risk results given the stated goal of the analysis to identify watersheds where potential exposures to MeHg from self-caught fish consumption could exceed the RfD.

• *Additional sources of uncertainty should be discussed in terms of their potential impact on risk estimates. These include: (1) Emissions inventory used in projecting total and U.S. EGU-attributable Hg deposition, including the projection of reductions in U.S. EGU emissions for the 2016 scenario, (2) air quality modeling with CMAQ including the prediction of future air quality scenarios, (3) ability of the Mercury Maps-based approach for relating Hg deposition to MeHg in fish to capture Hg hotspots, (4) the limited coverage that we have with fish tissue Hg data for watersheds in the U.S. and implications for the Hg Risk TSD, (5) the preparation factor used to estimate "as consumed" fish tissue Hg levels, (6) the proportionality assumption used to relate changes in Hg deposition to changes in fish tissue Hg levels at the watershed-level, (7) characterization of the spatial location of subsistence fisher populations (including the degree to which these provide coverage for high-consuming recreational fishers), and (8) application of the RfD to low SES populations and concerns that this could low-bias the risk estimates.* We expanded the discussion of sources of uncertainty presented in the revised TSD to address more fully these sources of uncertainty and the potential impact on risk estimates. Regarding these eight additional sources of uncertainty, we have (1) evaluated the uncertainties in the emissions and determined that while an important source of uncertainty, we are not able to quantify emissions uncertainty in the risk analysis, but have determined that the emissions inventories and emissions models represent the best available methods for predicting Hg emissions in the U.S., (2) evaluated the uncertainties in the Hg deposition predictions and determined that while an important source of uncertainty, we are not able to quantify uncertainty in Hg deposition in the Hg Risk TSD. Moreover, the CMAQ model used to estimate deposition is based on peer reviewed science and represents the best available method for predicting Hg deposition in the U.S., (3) evaluated the ability of the Mercury Maps-based approach for relating Hg deposition to MeHg in fish to capture Hg hotspots and determined that while finer resolution deposition modeling might reveal additional areas with elevated deposition, the 12 kilometer

[32] In the Revised Hg Risk TSD, this population is also referred to as the "typical female subsistence consumer."

[33] This change led to a very small increase in the number of watersheds with populations potentially at-risk. In the Hg Risk TSD accompanying the proposed rule, approximately 4 percent of modeled watersheds were excluded based on the SES-based filtering criteria.

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(km) deposition modeling matches well with the watershed size selected for the analysis, and thus the use of 12 km deposition estimates with the Mercury Maps based approach will not be a large source of uncertainty, (4) evaluated the limited coverage that we have with fish tissue Hg data for watersheds in the U.S. and implications for the Hg Risk TSD and based on the SAB's recommendations, we supplemented the coverage of watersheds by obtaining additional fish tissue Hg samples for areas heavily impacted by U.S. EGU deposition, thus reducing the uncertainty in the analysis, (5) evaluated the uncertainty in the preparation factor and determined that the level of uncertainty is low, and as such would have minimal impact on the risk estimates, (6) evaluated the uncertainty resulting from the proportionality assumption used to relate changes in Hg deposition to changes in fish tissue Hg levels at the watershed-level, and determined, based both on quantitative sensitivity analyses and qualitative assessments, that this source of uncertainty is not likely to greatly influence the results, and is not likely to have a specific directional bias, (7) evaluated the uncertainty related to characterization of the spatial locations of subsistence populations and determined that uncertainty could be reduced by focusing the risk estimates on female subsistence fishing populations, which are assumed to have the potential to fish in all watersheds, in response to SAB's concerns regarding potential exclusion of watersheds with fewer than 25 individuals and (8) evaluated the potential impact of the uncertainty in application of the RfD to low SES populations. The EPA determined that due to the method used in calculating the RfD, we have confidence that the RfD provides protection for low SES populations.

• *Expand the sensitivity analyses (over those included in the original risk assessment) to address uncertainty related to the use of the 75th percentile fish tissue Hg value (at each watershed) as the core risk estimate.* Based on the SAB's recommendation, we added a sensitivity analysis using the median fish tissue Hg estimate (at the watershed level). This sensitivity analysis showed that use of the median fish tissue Hg concentration instead of the 75th percentile resulted in a relatively small decrease (*i.e.,* 10 percent) in the estimates of watersheds with populations potentially at-risk, and did not substantially change the conclusions of the risk assessment.

C. Summary of Results of Revised Hg Risk TSD of Risks to Populations With High Levels of Self-Caught Fish Consumption

Based on the recommendations we received from the SAB, we revised the quantitative analysis of risk to subsistence fishing populations with high levels of fish consumption. Our revision to the quantitative risk results reflects three key recommendations from the SAB, including (1) addition of 824 watersheds based on additional fish tissue Hg sample data we obtained from states and the National Listing of Fish Advisories, (2) application of a 0.95 adjustment factor to the reported fish tissue Hg concentrations to account for the fraction that is MeHg, and (3) inclusion of all watersheds with fish samples that meet the filtering criteria [34] in representing potential exposures associated with increased risk of neurologic health effects for female subsistence fishing populations.

Based on these revisions, our estimates of the number and percent of modeled watersheds with populations potentially at-risk from exposure to EGU-attributable MeHg changed from those presented in the preamble to the proposed rule.[35] For the 99th percentile consumption scenario, the number of watersheds with fish tissue Hg samples where subsistence fishing populations may be at-risk from exposure to EGU-attributable MeHg increased from 672 to 917 (an increase of 36 percent). For this same scenario, the total percent of modeled watersheds with populations potentially at-risk from either risk metric (*i.e.,* MeHg exposure from U.S. EGUs alone exceeds the RfD or total MeHg exposure exceeds the RfD and U.S. EGUs contribute at least 5 percent) increased from 28 percent estimated at proposal to 29 percent after addressing SAB recommendations. The increase in the total percent of modeled watersheds with populations potentially at-risk using the expanded geographic coverage of watersheds provides additional confidence that emissions of Hg from U.S. EGUs pose a hazard to public health. For the 99th percentile consumption scenario, the percent of modeled watersheds with populations potentially at-risk from total potential exposures to MeHg that exceed the RfD and U.S. EGUs contribute at least 5 percent increased from 22 percent to 24 percent. For the 99th percentile consumption scenario, the percent of modeled watersheds with populations potentially at-risk based on Hg deposition from U.S. EGUs alone decreased from 12 percent to 10 percent.

The additional sensitivity analyses conducted in response to the SAB peer review showed that the estimates of the percent of modeled watersheds with populations potentially at-risk are robust to alternative assumptions about both the watersheds included in the analysis and the selection of the 50th percentile or 75th percentile fish tissue Hg level. Sensitivity analyses excluding entire states with the potential for historical loadings of Hg from non-air sources [36] resulted in an increase from 29 percent to 33 percent in the total percent of modeled watersheds with populations potentially at-risk exceeding either risk metric (*i.e.,* U.S. EGUs alone or total potential exposures to MeHg exceed the RfD and U.S. EGUs contribute at least 5 percent). Including only watersheds in the top 25th percentile of U.S. EGU deposition resulted in an increase in the total percent of modeled watersheds with populations potentially at-risk exceeding either risk metric, from 29 percent to 30 percent. Using the 50th percentile fish tissue Hg level resulted in a decrease in the total percent of modeled watersheds with populations potentially at-risk exceeding either risk metric, from 29 percent to 26 percent. On balance, these sensitivity analyses do not substantially reduce the percent of modeled watersheds with populations potentially at-risk, and thus confirm the finding that Hg emissions from U.S. EGUs pose a hazard to public health. In fact, given the broader coverage of modeled watersheds in the revised analysis, we have even greater confidence in our finding that Hg

[34] The watersheds were filtered to exclude watersheds that: (a) Were not freshwater, (b) did not have fish sampling data since 2000, (c) did not have fish larger than 7 inches in length, (d) contained active gold mines or (e) had substantial non-air Hg loading.

[35] Since the time of the analyses conducted in support of the proposed rule, the EPA updated IPM modeling to reflect the most recently available information, including public comments and the final CSAPR (see IPM Documentation for further details on these updates, which is available in the docket). Compared to the modeling conducted at proposal, these updates are projected to result in greater reductions in criteria pollutants, and also to have a slightly greater impact on U.S. EGU Hg emissions. Based on the revised projection for 2016, the EPA estimates that U.S. EGUs would emit 27 tons of Hg, as compared to the 29 tons we modeled for the Hg Risk TSD. We do not expect this 2 ton difference to substantially change the mercury risks reported in the preamble to the proposed rule, as this represents less than a 10 percent reduction in Hg emissions.

[36] The SAB noted that areas with substantially elevated fish tissue Hg levels could also be characterized by lakes and rivers with high natural methylation rates, and thus some of the states we excluded for this sensitivity analysis might not have fish tissue Hg levels that reflect non-U.S. EGU Hg loadings.

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emissions from U.S. EGUs pose a hazard to public health.

D. Peer Review of the Approach for Estimating Cancer Risks Associated With Cr and Ni Emissions in the U.S. EGU Case Studies of Cancer and Non-Cancer Inhalation Risks for Non-Hg HAP and EPA Response

As explained in the preamble to the proposed rule, the EPA submitted for peer review its characterization of the chemical speciation for the emissions of Cr and Ni used in the non-Hg HAP inhalation risk case studies. The remaining aspects of the non-Hg HAP case study risk assessments used methods that were previously peer reviewed. Specifically, the methodologies used to conduct the non-Hg case studies are consistent with those used to conduct inhalation risk assessments under EPA's Risk and Technology Review (RTR) program. Because the RTR assessments are considered to be highly influential science assessments, the methodologies used to conduct them were subject to a peer review by the SAB in 2009. The SAB issued its peer review report in May 2010.[37] The report endorsed the risk assessment methodologies used in the program, and made a number of technical recommendations for EPA to consider as the RTR program evolves.

The EPA's case studies identified Cr and Ni emissions as the key drivers of the estimated inhalation cancer risks for EGUs. Because these results hinged on specific scientific interpretations of data used to characterize EGU emissions of Cr and Ni, the EPA conducted a letter peer review of its analysis and interpretation of those data relative to the quantification of inhalation risks associated with Cr and Ni emissions from U.S. EGUs. The following sections describe the peer review process, enumerate the peer review charge questions presented to the peer review panel, summarize the key recommendations from the peer review, and summarize our responses to those recommendations.

1. Summary of Peer Review Process

The EPA asked three independent, external peer reviewers representing government, academic and the private sector to review of the methods for developing inhalation cancer risk estimates associated with emissions of Cr and Ni compounds from coal- and oil-fired EGUs in support of the appropriate and necessary finding. The approaches and rationale for the technical and scientific considerations used to derive inhalation cancer risks were summarized in the draft document entitled, "Methods to Develop Inhalation Cancer Risk Estimates for Chromium and Nickel Compounds." The peer reviewers received several charge questions (three questions on Cr and two questions on Ni, which are provided below) on the technical and scientific relevance of the approaches used to develop the inhalation unit risk estimates. The EPA also provided information on Cr speciation profiles for different industrial sources, as well as information on the Ni speciation of PM from oil-fired EGUs.

2. Peer Review Charge Questions

Below, we present the charge questions posed to the peer reviewers to help guide their review and development of recommendations to EPA on key issues relevant to the characterization of risks from EGU emissions containing either Cr or Ni compounds.

The EPA asked three questions regarding Cr and Cr compounds:

Question 1: Do EPA's judgments related to speciated Cr emissions adequately take into account the available Cr speciation data?

Question 2: Has EPA selected the species of Cr (*i.e.*, hexavalent Cr, Cr(VI)) that accurately represents the toxicity of Cr and Cr compounds?

Question 3: Are the assumptions used in past analysis scientifically defensible, and are there alternatives that EPA should consider for future analysis?

The EPA asked two questions regarding Ni and Ni compounds:

Question 1: Do EPA's judgments related to speciated Ni emissions adequately take into account available speciation data, including recent industry spectrometry studies?

Question 2: Based on the speciation information available and on what we know about the health effects of Ni and Ni compounds, and taking into account the existing Unit Risk Estimates (URE) values (*i.e.*, values derived for EPA's Integrated Risk Information System (IRIS), California Environmental Protection Agency (Cal EPA) and Texas Commission on Environmental Quality (TCEQ)), the EPA has provided several approaches[38] to derive unit risk estimates that may be more scientifically defensible than those used in past analyses. Which of the options presented would result in more accurate and defensible characterization of risks from exposure to Ni and Ni compounds? Are there alternative approaches that EPA should consider?

3. Summary of Peer Review Findings and Recommendations

Regarding Cr and Cr compounds, all three reviewers considered Cr(VI) as the species likely to be driving cancer risks based on solid evidence from the health effects database for Cr and Cr compounds. All three authors also considered EPA's use of the average of the range of the available speciation data (*i.e.*, 12 percent and 18 percent Cr(VI) contained in coal- and oil-fired EGUs, respectively) as a reasonable approach for the derivation of default speciation profiles to be used when there is no speciation data available. All reviewers agreed that there is high uncertainty associated with the variability in the speciation data available for Cr (*e.g.*, range of approximately 4 to 23 percent Cr(VI) from coal-fired units). One of the reviewers recommended several additional studies for EPA's consideration; the EPA considered these in finalizing the report.

Regarding Ni and Ni compounds, the reviewers agreed with the views of the international scientific bodies, which consider Ni compounds carcinogenic as a group. One reviewer recommended that the EPA review several additional Ni speciation data that suggests that sulfidic Ni compounds (which the reviewer considered as the most potent carcinogens within the group of all Ni compounds) are present at low levels in emissions from EGUs. In addition, this reviewer pointed out that there is a recently proposed model that may explain the differences in carcinogenic potential across Ni compounds.

4. The EPA's Responses to Peer Review Recommendations

We summarize EPA's basic responses to the peer review comments below, first for Cr-related issues, and second for Ni-related issues, which are reflected in the revised document.[39]

[37] U.S. Environmental Protection Agency—Science Advisory Board (U.S. EPA–SAB). 2010. *Review of EPA's draft entitled, "Risk and Technology Review (RTR) Risk Assessment Methodologies: For Review by the EPA's Science Advisory Board with Case Studies—MACT I Petroleum Refining Sources and Portland Cement Manufacturing". EPA–SAB–10–007. May. Available on-line at: http://yosemite.epa.gov/sab/sabproduct.nsf/4AB3966E263D943A8525771F00668381/$File/EPA-SAB-10-007-unsigned.pdf.*

[38] See section 3.3 of U.S. Environmental Protection Agency (U.S. EPA). 2011c. *Methods to Develop Inhalation Cancer Risk Estimates for Chromium and Nickel Compounds.* Office of Air Quality Planning and Standards. October.

[39] U.S. EPA, 2011c.

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a. Cr and Cr Compounds

In agreement with the peer reviewers and based on the health effects information available for Cr, the EPA assigns high confidence in the assumption that Cr(VI) is the carcinogenic species driving the risk of Cr-emitting facilities. In agreement with the reviews, the EPA considers derivation of default speciation profiles based on the mass of Cr(VI) a reasonable approach. As suggested by one of the reviewers, the EPA reviewed two potentially relevant studies, one of which showed coal combustion emissions containing as much as 43 percent Cr(VI),[40] which suggests that the EPA's quantitative approach could actually underestimate Cr(VI) inhalation risks. However, the other study reviewed by EPA on speciation of Cr in coal combustion showed Cr(VI) percentage levels close to detection limits (*i.e.,* 3 to 5 percent of total Cr, which was close to the limit of detection in this study).[41] Thus, the more recent speciation data available is unlikely to reduce the uncertainty of the Cr speciation analyses used by EPA as the bases for risk characterization analysis.

In agreement with the peer reviewers, the EPA also recognizes that the confidence in the default speciation profiles is low because the profiles are based on a limited data set with a wide range of percentages of Cr(VI) across the different samples.

b. Ni and Ni Compounds

Based on the views of the major scientific bodies mentioned above and the peer reviewers that commented on EPA's approaches to risk characterization of Ni compounds, the EPA considers all Ni compounds to be carcinogenic as a group and the EPA does not consider Ni speciation or Ni solubility to be strong determinants of Ni carcinogenicity. These scientific bodies also recognize that based on the data available, the precise Ni compound(s) responsible for the carcinogenic effects in humans is not always clear, and that there may be differences in the potential toxicity and carcinogenic potential across Ni compounds. Nevertheless, studies in humans indicate that various mixtures of Ni compounds (including Ni sulfate, sulfides and oxides, alone or in combination) encountered in the Ni refining industries may cause cancer in humans, and there is no reason to expect anything different from this for mixtures of Ni compounds from other emission sources. One of the reviewers suggested we consider views by some authors that believe that water soluble Ni, such as Ni sulfate, should not be considered a human carcinogen. This view is based primarily on a negative Ni sulfate 2-year rodent bioassay by the National Toxicology Program (NTP) (which is different from the positive 2-year NTP bioassay for Ni subsulfide).[42] [43] [44] One review article identifies the discrepancies between the animal and human data (*i.e.,* from studies of cancers in workers inhaling certain forms of Ni versus inhalation studies suggesting different carcinogenic potential in rodents with different Ni compounds) and states that the epidemiological data available clearly support an association between Ni and increased cancer risk, although the article acknowledges that the data are weakest regarding water soluble Ni. In addition, the EPA identified a recent review[45] that highlights the robustness and consistency of the epidemiological evidence across several decades showing associations between exposure to Ni and Ni compounds (including Ni sulfate) and cancer.

Regarding the second charge question on Ni compounds, two reviewers suggested using the URE derived by the TCEQ[46] for all Ni compounds as a group, rather than the one derived by the Integrated Risk Information System (IRIS, 1991)[47] specifically for Ni subsulfide. The third reviewer did not comment on an alternative approach. Considering this, to develop our primary risk estimate, the EPA decided to use a health protective approach by applying 100 percent of the current IRIS URE for Ni subsulfide, rather than assuming that 65 percent of the total mass of emitted Ni might be Ni subsulfide, as used in previous analyses. We used the IRIS URE value because IRIS values are preferred given the conceptual consistency with EPA risk assessment guidelines and the level of peer review that such values receive. We used 100 percent of the IRIS value because of the concerns about the potential carcinogenicity of all forms of Ni raised by the major national and international scientific bodies, and recommendations of the peer reviewers. Nevertheless, taking into account that there are potential differences in toxicity and/or carcinogenic potential across the different Ni compounds, and given that two URE values have been derived for exposure to mixtures of Ni compounds that are two to three fold lower than the IRIS URE for Ni subsulfide, the EPA also considers it reasonable to use a value that is 50 percent of the IRIS URE for Ni subsulfide for providing an estimate of the lower end of a plausible range of cancer potency values for different mixtures of Ni compounds.

Although this report focused primarily on cancer risks associated with emissions containing Ni compounds, it is important to note that comparative quantitative analyses of non-cancer toxicity of Ni compounds indicate that Ni sulfate is as toxic or more toxic than Ni subsulfide or Ni oxide which does not support the notion that the solubility of Ni compounds is a strong determinant of its toxicity.[48] [49]

E. Summary of Results of Revised U.S. EGU Case Studies of Cancer and Non-Cancer Inhalation Risks for Non-Hg HAP

Based on the results of the peer review and public comments on the non-Hg case study chronic inhalation risk assessment, we made several changes to the emissions estimates, dispersion modeling, and risk characterization for the modeled case study facilities. Key changes include (1) changes in emissions, (2) changes in stack parameters for some facilities based on new data received during the

[40] Galbreath KC, Zygarlicke CJ. 2004. "Formation and chemical speciation of arsenic-, chromium-, and nickel-bearing coal combustion $PM_{2.5}$," *Fuel Process Technol* 85:701–726.

[41] Huggins FE, Najih M, Huffman GP. 1999. "Direct speciation of chromium in coal combustion by-products by X-ray absorption fine structure spectroscopy," *Fuel Process Technol* 78:233–242.

[42] Oller A. 2002. "Respiratory carcinogenicity assessment of soluble nickel compounds." *Environ Health Perspect.* 110:841–844.

[43] Heller JG, Thornhill PG, Conard BR. 2009. "New views on the hypothesis of respiratory cancer risk from soluble nickel exposure; and reconsideration of this risk's historical sources in nickel refineries." *J Occup Med Toxicol.* 4:23.

[44] Goodman JE, Prueitt RL, Thakali S, and Oller AR. 2011. "The nickel iron bioavailability model of the carcinogenic potential of nickel-containing substances in the lung." *Crit Rev Toxicol* 41:142–174.

[45] Grimsrud TK and Andersen A. "Evidence of carcinogenicity in humans of water-soluble nickel salts." *J Occup Med Toxicol.* 2010. 5:1–7. Available online at *http://www.ossup-med.com/content/5/1/7.*

[46] Texas Commission on Environmental Quality (TCEQ). 2011. *Development Support Document for nickel and inorganic nickel compounds.* Available online at *http://www.tceq.state.tx.us/assets/public/implementation/tox/dsd/final/june11/nickel_&_compounds.pdf.*

[47] U.S. EPA, 1991. *Integrated Risk Information Service (IRIS) assessment for nickel subsulfide.* Available at: *http://www.epa.gov/iris/subst/0273.htm.*

[48] Haber LT, Allen BC, Kimmel CA. 1998. "Non-Cancer Risk Assessment for Nickel Compounds: Issues Associated with Dose-Response Modeling of Inhalation and Oral Exposures." *Toxicol Sci.* 43:213–229.

[49] National Toxicology Program (NTP). 1996. *Technical Report Series No. 454, Toxicology and carcinogenesis studies of nickel sulfate hexahydrate.* July. Available online at *http://ntp.niehs.nih.gov/ntp/htdocs/LT_rpts/tr454.pdf.*

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public comment period, (3) use of updated versions of AERMOD and its input processors (AERMAP, AERMINUTE, and AERMET), and (4) use of 100 percent of the current IRIS URE for Ni subsulfide to calculate Ni-associated inhalation cancer risks (rather than assuming that the Ni might be 65 percent as potent as Ni subsulfide).

Based on estimated actual emissions, the highest estimated individual lifetime cancer risk from any of the 16 case study facilities was 20 in a million, driven by Ni emissions from the one case study facility with oil-fired EGUs. Of the facilities with coal-fired EGUs, five facilities had maximum individual cancer risks greater than one in a million [50] (the highest was five in a million), with the risk from four due to emissions of Cr(VI) and the risk from one due to emissions of Ni.[51] There were also two facilities with coal-fired EGUs that had maximum individual cancer risks equal to one in a million. All of the facilities had non-cancer Target Organ Specific Hazard Index (TOSHI) [52] values less than one, with a maximum TOSHI value of 0.4 (also driven by Ni emissions from the one case study facility with oil-fired EGUs).

Since these case studies do not cover all facilities in the category, and since our assessment does not include the potential for impacts from different EGU facilities to overlap one another (*i.e.,* these case studies only look at facilities in isolation), the maximum risk estimates from the case studies likely underestimates true maximum risks for the source category.

Based on the fact that six U.S. EGUs were estimated to meet or exceed the CAA section 112(c)(9) criterion of one in a million, EGUs cannot be removed from the list of source categories to be regulated under CAA section 112.

[50] A risk level of 1 in a million implies a likelihood that up to one person, out of one million equally exposed people would contract cancer if exposed continuously (24 hours per day) to the specific concentration over 70 years (an assumed lifetime). This would be in addition to those cancer cases that would normally occur in an unexposed population of one million people.

[51] When the lower end of the cancer potency range for Ni was used to develop risk estimates, 5 of the 16 facilities had maximum cancer risks exceeding 1 in a million, and the maximum individual cancer risk for any single facility fell to 10 in a million.

[52] The target-organ-specific hazard index (TOSHI) is a metric used to assess whether there is an appreciable risk of deleterious (noncancer) effects to a specific target organ due to continuous inhalation exposures over a lifetime. If a TOSHI value is less than or equal to one, such effects are unlikely. For TOSHI values greater than one, there is an increased risk of such effects.

F. Public Comments and Responses to the Appropriate and Necessary Finding

1. Legal Aspects of Appropriate and Necessary Finding

a. History of Section 112(n)(1)(A)

Comment: One commenter provided a detailed history of EPA's regulatory actions concerning EGUs and implementation of CAA section 112(n)(1)(A). The same commenter implies that the EPA's 2000 appropriate and necessary finding and listing of EGUs was flawed because the Agency did not comply with CAA section 307(d) rulemaking process. The commenter sought review of the 2000 notice in the U.S. Court of Appeals for the District of Columbia Circuit, which was dismissed by the D.C. Circuit. *Utility Air Regulatory Group* v. *EPA,* No. 01–1074 (D.C. Cir. July 26, 2001). The commenter then characterizes at length the 2005 EPA action that revised the interpretation of CAA section 112(n)(1)(A) and, which the D.C. Circuit concluded illegally removed EGUs from the CAA section 112(c) list of sources that must be regulated under CAA section 112. *See New Jersey* v. *EPA,* 517 F.3d 574 (D.C. Cir. 2008). The commenter notes that the D.C. Circuit did not rule on the legal correctness or the sufficiency of the factual record supporting EPA's 2000 listing decision or on the factual correctness of EPA's later decision to reverse its CAA section 112(n)(1)(A) determination. The commenter noted further that the D.C. Circuit indicated that the listing decision could be challenged when the Agency issued the final CAA section 112(d) standards pursuant to CAA section 112(e)(4). The commenter concluded by asserting that the Agency could not ignore the history associated with the regulation of EGUs under section 112 and that two earlier dockets—Docket ID. No. A–92–55 and Docket ID. No. EPA–HQ–OAR–2002–0056—are also part of this long rulemaking effort and must be accounted for in conjunction with Docket No. EPA–HQ–OAR–2009–0234 if all pertinent material and comments are to be part of the rulemaking record.

Response: The commenter characterizes the regulatory history of the rule EPA proposed on May 3, 2011. To the extent that characterization is inconsistent with the lengthy regulatory history EPA provided in the preamble to the May 3, 2011 rule, we disagree. We address several of the statements in more detail below.

First, the commenter makes much of the fact that the EPA did not go through CAA section 307(d) notice and comment rulemaking when making the appropriate and necessary finding and listing decision in 2000. However, the commenter's complaint is without foundation. The CAA does not require CAA section 307(d) rulemaking for listing decisions. In fact, CAA section 112(e)(4) specifically provides that listing decisions may only be challenged "when the Administrator issues emission standards for such * * * [listed] category." Second, the commenter challenged the listing decision in the U.S. Court of Appeals for the District of Columbia Circuit (Court) and, on July 26, 2001, the Court granted EPA's motion to dismiss that action based on the plain language of CAA section 112(e)(4). Moreover, in addition to the 2000 notice, the EPA clearly articulated its basis for listing EGUs in this proposed rule, which is consistent with CAA section 307(d), and the commenter was provided an ample opportunity to comment. Finally, the commenter asserts that the rulemaking docket for this action is incomplete because the Agency did not include two earlier dockets—Docket ID. No. A–92–55 and Docket ID. No. EPA–HQ–OAR–2002–0056—for the Section 112(n) Revision Rule, 70 FR 15994 (March 29, 2005), and the reconsideration of the Section 112(n) Revision Rule, 71 FR 33388 (June 9, 2006), respectively. The commenter is incorrect because EPA incorporated by reference the two dockets at issue. *See* EPA–HQ–OAR–2009–0234–3056.

Comment: One commenter stated that the EPA has assessed the public health risks posed by HAP emissions from coal- and oil-fired EGUs for the last 40 years. According to the commenter, throughout that time, the EPA has come to a single repeated conclusion that HAP emissions from EGUs pose little or no risk to public health. Based on this conclusion, the EPA has properly chosen not to require EGUs to install expensive, new pollution control equipment to control HAP emissions. The commenter asserts that, in this proposed rule, the EPA shifts its opinion on the health impacts of EGU HAP emissions 180 degrees and now seeks to impose sweeping regulatory requirements on all power plants. According to the commenter, the EPA's newfound concern about HAP emissions from EGUs is not based on new and different assessments of the public health consequences of EGU HAP emissions but instead on health benefits from the reduction of non-hazardous air pollutants, primarily PM, which the Agency is required to regulate under other provisions of the CAA. One

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commenter stated that for decades, the EPA set primary ambient air quality standards that protect public health with an adequate margin of safety, CAA section 109(b)(1), and set secondary standards that are [sic] "requisite to protect the public welfare from any known or anticipated adverse effects associated with the presence of such air pollutant in the ambient air," CAA 109(b)(2). The commenter notes that even if EPA now views those past PM standards as inadequate, the EPA has ongoing regulatory proceedings in which it can address any perceived health concerns. The commenter concludes that regulation of EGU HAP emissions under CAA section 112 is an unlawful way to address those concerns.

Response: The commenter is incorrect in its assertion that the Agency has consistently concluded that HAP emissions from EGUs do not present a hazard to public health. In the 2000 finding, the Agency concluded that HAP emissions from coal- and oil-fired EGUs do pose a hazard to public health and determined that it was appropriate and necessary to regulate such units under CAA section 112. As a result of that finding, the EPA added coal- and oil-fired EGUs to the CAA section 112(c) list of source categories for which emission standards are to be established pursuant to CAA section 112(d). Further, in support of the proposed rule, the EPA conducted additional extensive quantitative and qualitative analyses, which confirm that it remains appropriate and necessary to regulate EGUs under CAA section 112. Among other things, those analyses demonstrate that emissions from coal- and oil-fired EGUs continue to pose a hazard to public health. The commenter also fails to note that the EPA found that HAP emissions from EGUs pose a hazard to the environment as well.

The commenter seems confused about the basis for the Agency's appropriate and necessary finding because it maintains that the EPA made the appropriate and necessary finding based on the health co-benefits attributable to PM reductions that will be achieved as a result of the Agency's regulation of HAP emissions from EGUs. Nowhere in the May 2011 proposal does EPA state that it based the appropriate and necessary finding on hazards to public health attributable to PM emissions. The commenter's allegation lacks foundation. The appropriate and necessary finding unmistakably focuses on the hazards to public health and hazards to the environment associated with HAP emissions from EGUs.

Comment: One commenter stated that CAA section 112 required EPA to make a risk-based determination in order to regulate HAP. According to the commenter, the EPA may regulate substances "reasonably * * * anticipated to result in an increase in mortality or increase in serious illness" to a level that protects public health with an "ample margin of safety." According to the commenter, the EPA has regulated a number of HAP emitted from industrial source categories other than EGUs.

As for EGUs, according to the commenter, the EPA found that the combustion of fossil fuels produces extremely small emissions of a broad variety of substances that are present in trace amounts in fuels and that are removed from the gas stream by control equipment installed to satisfy other CAA requirements. The commenter stated that the EPA, in past reviews, found that these HAP emissions did not pose hazards to public health. *See* 48 FR 15076, 15085 (1983) (radionuclides). the commenter further stated that "[i]n the case of Hg specifically, the EPA found that "coal-fired power plants * * * do not emit mercury in such quantities that they are likely to cause ambient mercury concentration to exceed" a level that "will protect public health with an ample margin of safety." 40 FR 48297–98 (October 19, 1975) (Hg); 52 FR 8724, 8725 (March. 19, 1987) (reaffirming Hg conclusion).

According to the commenter, in the late 1980s, the EPA was concerned that its prior risk assessments of individual HAP emissions from fossil-fuel-fired power plants may not reflect the total risks posed by all HAP emitted by those sources. The commenter states that the EPA modeled the risks posed by all HAP emitted by power plants (very much like the analyses the Agency would conduct for the Utility Study ten years later). The commenter asserts that the modeling again failed to identify threats to public health that warranted regulation under an "ample margin of safety" test.

Response: The commenter's statements concerning the pre-1990 CAA are not relevant to the current action. Congress enacted CAA section 112(n)(1) as part of the 1990 amendments to the Act. That provision requires, among other things, that the Agency evaluate the hazards to public health posed by HAP emissions from fossil-fuel fired EGUs. Had Congress concluded, as commenter appears to assert, that HAP emissions from EGUs did not pose a hazard to public health or the environment, it defies reason that Congress would have required EPA to conduct the three studies at issue in CAA section 112(n)(1) (titled "Electric utility steam generating units") and regulate EGUs under section 112 if the Administrator determined in her discretion that it was appropriate and necessary to do so. The Agency complied with the statutory mandates in CAA section 112(n)(1) in conducting the studies and reasonably exercised its discretion in making the appropriate and necessary finding.

We acknowledge that Congress treated radionuclide emissions from EGUs differently. For radionuclides from EGUs (and certain other sources), Congress included CAA section 112(q)(3), which authorizes but does not require the Agency to maintain the regulations of radionuclides in effect prior to the 1990 amendments. The fact that Congress made an exception for radionuclides and no other HAP from EGUs further demonstrates that the HAP-related actions EPA took with regard to EGUs prior to the 1990 amendments to the CAA are not germane.

As for the commenter's statements about Hg emissions from EGUs, we find their conclusions wholly inconsistent with CAA section 112(n)(1). That provision is titled "Electric utility steam generating units," and it directs EPA to conduct two Hg-specific studies. *See* CAA sections 112(n)(1)(B) and 112(n)(1)(C). The commenter's suggestion that the EPA could or should rely on assessments of Hg from EGUs conducted prior to the 1990 amendments is not tenable.

Finally, the commenter stated that the EPA conducted a risk assessment of all HAP from EGUs prior to the 1990 amendments and that the Agency did not identify any HAP that failed the "ample margin of safety" test. The commenter did not cite the study or provide any information to support the statements so we are unable to respond to the alleged study directly; however, the risk assessments conducted in support of the appropriate and necessary finding, as well as the 2000 finding, demonstrate that HAP emissions from EGUs pose hazards to public health and the environment.

b. Interpretation of "Appropriate" and "Necessary"

Comment: One commenter stated that in the preamble to the proposed rule, the EPA sets out its "interpretation of the critical terms in CAA section 112(n)(1)," arguing that this latest interpretation is "wholly consistent with the CAA" and with the Agency's earlier "2000 finding." *See* 76 FR 24976, 24986 (May 3, 2011). The commenter stated that throughout the proposal EPA tries to suggest that it is returning to

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some earlier, "correct" interpretation of CAA section 112(n)(1) set forth in its 2000 action. *See, e.g.,* 76 FR 24989 ("The Agency's interpretation of the term 'appropriate' * * * is wholly consistent with the Agency's appropriate finding in 2000"); id. at 24992 ("Our interpretation of the necessary finding is reasonable and consistent with the 2000 finding"). According to the commenter, the EPA did not provide in 2000 any interpretation of what it now characterizes as the "critical terms" of section 112(n)(1). *See, e.g.,* 70 FR 15999 n.13 (the "2000 finding does not provide an interpretation of the phrase 'after imposition of the requirements of the Act' "); id. at 16000/2 (in 2000, the EPA "did not provide an interpretation of the term 'appropriate' "); 76 FR 24992 (the "Agency did not expressly interpret the term necessary in the 2000 finding"). The commenter believes that for that reason alone, it is impossible to credit EPA's assertion that it "appropriately concluded that it was appropriate and necessary to regulate hazardous air pollutants * * * from EGUs" in 2000, and that it is today merely "confirm[ing] that finding and conclud[ing] that it remains appropriate and necessary to regulate these emissions.* * *" [53]

Response: The commenter disagrees with certain statements in the preamble to the proposed rule that provide that the Agency's interpretation of CAA section 112(n)(1) is reasonable and consistent with the 2000 finding. It is difficult to decipher the exact complaint that the commenter has with EPA's proposed rule in this regard, but the commenter does assert that "the Agency did not provide in 2000 any interpretation of what it now characterizes as the "critical terms" of CAA section 112(n)(1)." The commenter's assertion lacks foundation. Although the 2000 finding did not provide detailed interpretations of the regulatory terms at issue, it discussed the types of considerations relevant to the appropriate and necessary inquiry. For example, it is clear that in 2000, the Agency was concerned with the then current hazards to public health and the environment when assessing whether it was appropriate to regulate EGUs under section 112.[54] In addition, when evaluating whether it was necessary to regulate utilities, the Agency stated that it was necessary to regulate HAP emissions from U.S. EGUs under section 112 because the implementation of the other requirements of the Act would not adequately address the serious public health and environmental hazards arising from HAP emissions from EGUs. The Agency also specifically noted that "section 112 is the authority intended to address" hazards to public health and the environment posed by HAP emissions. *Id.*

The detailed interpretation set forth in the preamble to the proposed rule is consistent with the 2000 finding, but EPA does not assert that the interpretation is in any way necessary to support the factual conclusions reached in the 2000 finding. Instead, we noted in the preamble to the proposed rule that our interpretation is consistent with the 2000 finding because in 2005 we interpreted the statute in a manner that was not consistent with the 2000 finding. The commenter has provided no legal support for its position that the Agency erred in interpreting the statute in a manner that is consistent with a prior factual finding.

Comment: Several commenters assert that in the 1990 amendments to the Clean Air Act, Congress directed the EPA to base its determination regarding regulation of fossil-fuel-fired generating units on consideration of any adverse public health effects identified in the study mandated by the first sentence of section 112(n)(1)(A) and that Congress did not dictate in section 112(n)(1)(A) that the EPA must regulate electric utility steam generating units under section 112.

According to the commenters the sponsor of the House bill that became section 112(n)(1)(A) provides an explanation that contradicts the EPA's approach to regulating EGUs:

> Pursuant to section 112(n), the Administrator may regulate fossil fuel fired electric utility steam generating units only if the studies described in section 112(n) clearly establish that emissions of any pollutant, or aggregate of pollutants, from such units cause a significant risk of serious adverse effects on the public health. Thus, * * * he may regulate only those units that he determines—after taking into account compliance with all provisions of the act and any other Federal, State, or local regulation and voluntary emission reductions—have been demonstrated to cause a significant threat of serious adverse effects on the public health.

136 Cong. Rec. H12,934 (daily ed. Oct. 26, 1990) (statement of Rep. Michael Oxley).

The commenters stated that the EPA position is premised on the assumption that "regulation under section 112" necessarily means "regulation under 112(d)" and falsely premised on the assumption that source categories listed by operation of section 112(n)(1)(A) cannot be regulated differently. The commenters conclude that the language of section 112(n)(1)(a) reflects Congress' intent that "regulation of HAP from EGUs was not intended to operate under section 112(d) but was instead intended to be tailored to the findings of the utility study mandated by section 112(n)(1)(A)."

Response: The commenters maintain that the Agency's interpretation of CAA section 112(n)(1) is flawed in many respects. The primary support for one commenter's arguments against EPA's interpretation, including in the comment above, is legislative history in the form of statements from one Congressman, Representative Oxley. The Supreme Court has repeatedly stated that the statements of one legislator alone should not be given much weight. *See Brock* v. *Pierce County,* 476 U.S. 253, 263 (1986) (finding that "statements by individual legislators should not be given controlling effect, but *when they are consistent with the statutory language and other legislative history, they provide evidence of Congress' intent.*") (*emphasis added*) (citation omitted); *Garcia, et al.,* v. *U.S.,* 469 U.S. 70, 78 (1984), citing *Zuber* v. *Allen,* 396 U.S. 168, 187 (1969) (reiterating its prior findings, the Court indicated that isolated statements "are 'not impressive legislative history.' "); *Weinberger, et al.,* v. *Rossi et al.,* 456 U.S. 25, 35 (declining to make a ruling based on "one isolated remark by a single Senator"); *Consumer Product Safety Comm., et al.* v. *GTE Sylvania, Inc., et al.,* 447 U.S. 102, 117–118 (1980) (declining to give much weight to isolated remarks of one Representative); *Chrysler Corp.* v. *Brown, et al.,* 441 U.S. 281, 311 (1979) (finding that "[t]he remarks of a single legislator, even the sponsor, are not controlling in analyzing legislative history."); *Zuber,* 396 U.S. at 186 (concluding that "[f]loor debates reflect at best the understanding of individual Congressmen."); and *U.S.* v. *O'Brien,* 391 U.S. 367, 384 (1968) (in evaluating the statements of a handful of Congressmen, the Court concluded that "[w]hat motivates one legislator to make a speech about a statute is not necessarily what motivates scores of others to enact it. * * *."). As these cases show, the Supreme Court does not give weight to the statements of an individual legislator, except when the statements are supported by other legislative history and the clear intent of the statute. The commenters cited no case law that would support reliance on such limited legislative history.

The commenter has not cited any other legislative history to support

[53] *Id.* at 24,977/3.

[54] 65 FR 79830.

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Representative Oxley's statement, and the lack of additional support makes the statement of little utility or import under the case law. In fact, there does not appear to be anything in the House, Senate, or Committee Reports that supports Oxley's statement. The lack of support for Oxley's statement in the Committee Report is particularly telling since, as the commenter notes, the House and Senate bills required different approaches to regulating EGUs under section 112, with the Senate bill requiring EGUs be regulated prior to the Utility Study. In fact, legislative statements from Senator Durenberger, a supporter of the Senate version, demonstrate that others would almost certainly not have agreed with Oxley's interpretation. For example, Senator Durenberger stated, "It seems to me inequitable to impose a regulatory regime on every industry in America and then exempt one category, especially a category like power plants which are a significant part of the air toxics problem."

Senator Durenberger discussed the negotiations with the Administration and the industry push to avoid regulation, including industry arguments for not regulating Hg from U.S. EGUs:

> The utility industry continued to adamantly oppose [regulation under section 112]. First, they argued that mercury isn't much of an environmental problem. But as the evidence mounted over the summer and it became clear that mercury is a substantial threat to the health of our lakes, rivers and estuaries and that power plants are among the principal culprits, they changed their tactic. Now they are arguing that mercury is a global problem so severe that just cleaning up U.S. power plants won't make enough of a difference to be worth it. They've gone from 'we're not a problem' to 'you can't regulate us until you address the whole global problem.' Recasting an issue that way is not new around here. So, it is not a surprise. But it does suggest the direction in which this debate will be heading in the next few years.

136 Cong. Rec. 36062 (October 27, 1990).

Senator Durenberger also explained why the House version was adopted:

> Given that a resolution of the difficult issues in the conference were necessary to conclude work on this bill, the Senate proposed to recede to the House provision which was taken from the original administration bill. It provides for a 3-year study of utility emissions followed by regulation to the extent that the Administrator finds them necessary.

Id.

Senator Durenberger's statements indicate that it is unlikely that he would agree with Oxley's interpretation of CAA section 112(n)(1), a provision that provides the Agency with considerable discretion, and nothing indicates that others in the Senate (or for that matter anyone else in the House) would agree with that interpretation. Given the Supreme Court's views on the use of such limited legislative history, the EPA reasonably declined to consider (or even discuss) the legislative history in the preamble to the proposed rule and we believe it would be improper to ascribe Representative Oxley's statements to the entire Congress.

Moreover, Representative Oxley's statement directly conflicts with the statutory text. Representative Oxley stated that "[the Administrator may regulate only those units that he determines—*after taking into account compliance with all provisions of the act and any other Federal, State, or local regulation and voluntary emission reductions*—have been demonstrated to cause a significant threat of serious adverse effects on the public health." 136 Cong. Rec. H12934 (daily ed. Oct. 26, 1990), reprinted in 1 1990 Legis. Hist. at 1416–17 *(emphasis added).* However, the Utility Study required under CAA section 112(n)(1)(A) directs the Agency to consider the hazards to public health reasonably anticipated to occur after "imposition of the requirements of [the Clean Air Act]." EPA was not required to consider state or local regulations or voluntary emission reduction programs in the Utility Study, and that study is the only condition precedent to making the appropriate and necessary finding.[55]

The legislative history the commenters rely on is not controlling. The Agency believes that it has reasonably interpreted section 112(n)(1)(A), for all the reasons described herein and in the proposal. The commenters also cite Representative Oxley's statements as support for alternative interpretations of CAA section 112(n)(1). We believe that any arguments that rely on such limited legislative history are without merit.

Comment: One commenter stated that the EPA does acknowledge that, in many significant respects, its new interpretation of CAA section 112(n)(1) "differs from that set forth" in the Agency's 2005 rulemaking, but argues that its change of position is permissible. *See* 76 FR 24988/1 ("[T]o the extent our interpretation differs from that set forth in the 2005 Action, we explain the basis for that difference and why the interpretation, as set forth in this preamble, is reasonable."). In support, commenters note that the EPA cites *National Cable & Telecommunication Ass'n* v. *Brand X Internet Services,* 545 U.S. 967 (2005). The commenters agree that it is true that, in *Brand X Internet Services,* the Supreme Court explained that, if an agency "adequately explains the reasons for a reversal of policy," such change is "not invalidating," since the "whole point of Chevron is to leave the discretion provided by the ambiguities of a statute with the implementing agency." 545 U.S. at 981 (internal quotations omitted). The commenters maintain that all Brand X Internet Services was saying is that "[a]gency inconsistency is not a basis for declining to analyze the agency's interpretation under the *Chevron* framework." *Id.*

According to the commenter, it is not enough that the EPA has purported to "explain" why it has abandoned the interpretation of CAA section 112(n)(1) adopted in 2005. The commenter states that under the first step of *Chevron,* the Agency's latest interpretation must still be consistent with congressional intent. *See Chevron* v. *NRDC,* 467 U.S. at 842–43. The commenters state that under the second step of Chevron, if there is discretion for EPA to exercise in interpreting the "critical terms" of CAA section 112(n)(1), the Agency must properly define the range of that discretion and then act reasonably in exercising that discretion. *See Chevron,* 467 U.S. at 843; *see also Village of Barrington, Ill.* v. *Surface Transportation Bd.,* No. 09–1002 (D.C. Cir. Mar. 15, 2011).The commenters allege that the EPA failed to properly define and exercise the scope of its discretion. In each instance, the commenter maintains that the Agency has departed from the correct interpretation of CAA section 112(n)(1) that it adopted in 2005, seizing instead upon a new approach that is contrary to the plain language of the CAA itself, as interpreted after considering the statements of Representative Oxley.

Response: The commenter appears to argue that the EPA's interpretation of CAA section 112(n)(1) is not consistent with the plain language of the statute, implying that the statute is clear and must be evaluated under step one of Chevron. *See Chevron* v. *NRDC,* 467 U.S. 837 842–42 (1984) (finding that when the legislative intent is clear no additional analysis is required).

[55] In addition, the EPA only considered CAA requirements in the Utility Study and this was the correct approach because Congress knew how to require consideration of non-Federal requirements when directing EPA to conduct a study or assessment. See CAA section 112(n)(5) (Congress required EPA to conduct an assessment of hydrogen sulfide from oil and gas extraction activities and provided that the assessment "shall include review of existing State and industry control standards, techniques and enforcement.").

However, as noted above, much of the commenter's argument that the plain language of the statute precludes EPA's interpretation is based on the unpersuasive legislative history discussed above. As explained in the preamble to the proposed rule, the statute directs the Agency to determine whether it is appropriate and necessary to regulate EGUs under section 112. As the D.C. Circuit has held, the terms "appropriate" and "necessary" are very broad terms. Because these terms are broad they are susceptible to different interpretations. We believe we have reasonably interpreted the appropriate and necessary language in section 112(n)(1)(A). To the extent that interpretation differs from the one set forth in 2005, we have fully explained the basis for such changes. *See* 76 FR 24986–24993 (setting forth the Agency's interpretation of section 112(n)(1)).

Furthermore, we properly considered the scope of our discretion in interpreting the statute as explained in detail in the preamble to the proposed rule. We believe the interpretation set forth in the preamble to the proposed rule is consistent with the Act and, therefore, the Agency should be afforded deference pursuant to *National Cable & Telecommunication Ass'n* v. *Brand X Internet Services,* 545 U.S. 967 (2005).

Comment: A number of commenters agreed with the Agency's interpretation of section 112(n)(1) and the terms appropriate and necessary. The commenters also agreed that the EPA's interpretation of that provision was reasonable and consistent with the statute.

Response: We agree with the commenters and appreciate their support.

Comment: One commenter asserts that the EPA's ultimate motivation for rejecting its prior interpretation of CAA section 112(n)(1) and embracing this flawed new approach is made clear from the very outset of the proposal. According to the commenter, the EPA touts the fact that "one consequence" of the MACT rule would be that the "market for electricity in the U.S. will be more level" and "no longer skewed in favor of the higher polluting units that were exempted from the CAA at its inception on Congress' assumption that their useful life was near an end." *See* 76 FR 24979/2. The MACT rule would "require companies to make a decision—control HAP emissions from virtually uncontrolled sources" or else "retire these sometimes 60 year old units and shift their emphasis to more efficient, cleaner modern methods of generation, including modern coal-fired generation." Id.

The commenter stated that this remarkably forthright statement establishes that the underlying basis for EPA's proposal to regulate EGUs under CAA section 112 is not to address any "hazards to public health" that might be attributed to the emission by EGUs of HAP listed under CAA section 112(b). Rather, according to commenter, the EPA is utilizing the regulation of EGUs under CAA section 112 as a means to an entirely different end: To force the imposition of controls that will also have the result of reducing non-HAP emissions (primarily PM) or force the shutdown of those units for which the cost of such controls would be prohibitive. At the same time, according to commenter, the EPA tacitly acknowledges that it cannot hope to make out a case that the regulation of EGU HAP emissions is "appropriate and necessary" within the meaning of CAA section 112(n)(1). The commenter asserts that the only HAP whose health-related benefits EPA quantifies is Hg. Elsewhere, the commenter stated that the EPA contends there are "additional health and environmental effects" attributable to HAP other than Hg, but admits that it has "not quantified" those risks due supposedly to "insufficient information." *See* 76 FR 24999/2. With respect to Hg the commenter stated that the benefits are so questionable and miniscule, some $4 million to $6 million (given a 3 percent discount rate), that compared to the total social costs of the rule (*i.e.,* nearly $11 billion) the rule cannot be justified were EPA properly to interpret CAA section 112(n)(1) and undertake the sort of regulatory analysis Congress intended. The commenter stated that the reason that the EPA touts in this rulemaking the health benefits EPA attributes to the reduction of non-hazardous air pollutants (again, primarily PM), the regulation of which is authorized under provisions of the CAA apart from CAA section 112, is to elide the inconvenient truth regarding the truly trivial nature of the benefits attributable to HAP regulation itself. The commenter concludes that the EPA distorts CAA section 112(n)(1)(A) "beyond all recognition."

One commenter stated that the EPA is directed by CAA section 112(n)(1)(A) to study the "hazards to public health anticipated to occur as a result of emissions" by EGUs of "pollutants listed under subsection (b) of this section"—*i.e.,* HAP and HAP alone. Thereafter, the EPA is authorized to regulate EGU HAP emissions if, and only if, they determine that "such regulation" of HAP emissions is "appropriate and necessary" to address the "hazards to public health" that may be attributable to HAP emissions. According to the commenter, by contrast, in this rulemaking, the EPA has seized upon the fact that the control of EGU HAP emissions will also control non-HAP (such as PM), and then seeks to justify the regulation of HAP emissions based almost entirely on the health benefits of the reductions in non-HAP emissions that would be coincidentally achieved. The commenter believes that this "regulatory sleight-of-hand" runs afoul of congressional intent and is unlawful.

Response: The commenter alleges that the health-related benefits to regulating HAP emissions from EGUs are "questionable and miniscule," and that the only real benefits stem from non-HAP emissions, such as PM. The commenter also implies that regulation of HAP is nothing more than a straw man and that the Agency's ultimate goal is to regulate other pollutants, and specifically PM. These allegations are wholly without merit. The Agency has conducted comprehensive technical analyses that confirm that HAP emissions from EGUs pose a hazard to public health. The analyses are discussed at length elsewhere in this final rule, and a review of the proposed and final rules utterly refutes commenter's assertion that PM reductions form the basis for the appropriate and necessary finding. In addition, the commenter appears to ignore the Agency's findings concerning the hazards to public health and the environment posed by HAP emissions simply because the Agency is not able to quantify many of the benefits associated with reductions of HAP emissions from EGUs or because the estimated HAP benefits that are quantified are small in relation to the co-benefits achieved through reductions in non-HAP air pollutants, such as PM and SO_2, which are surrogates for certain HAP. The Agency is regulating EGUs pursuant to section 112(d) for all of the reasons explained in the preamble and discussed elsewhere in this response to comments. The commenter fails to recognize that the statute neither requires a cost-benefit analysis prior to finding it appropriate and necessary to regulate EGUs, nor requires such analysis prior to setting emission standards. Indeed, Congress expressly precluded consideration of costs when setting MACT floors. As explained below, the EPA does not believe that it is appropriate to consider costs when

determining whether to regulate EGUs under CAA section 112.

Comment: One commenter stated that the EPA has ignored the language and intent of CAA section 112(n)(1)(A), as interpreted based on Representative Oxley's statements, and that the Agency's interpretation of this provision violates step one of Chevron. Under Chevron where the "intent of Congress is clear," that is the "end of the matter," for both the implementing agency and a reviewing court "must give effect to the unambiguously expressed intent of Congress." Chevron, 467 U.S. at 842–43. The commenter asserts that the legislative history of CAA section 112(n)(1)(A) "sheds considerable light on Congress' unique approach to regulation of EGUs under CAA § 112." According to the commenter, on April 3, 1990, the Senate passed S. 1630. The Senate bill would have required EPA to list EGUs under CAA section 112(c) and to regulate them under the MACT provisions of CAA section 112(d). *See* S. 1630 section 301, 3 1990 Legis. Hist. at 4407. Thereafter, the House of Representatives passed a modified version of S. 1630 on May 23, 1990. This House version substantially changed the provisions of CAA section 112 as they applied to EGUs. *See* 1 1990 Legis. Hist. at 572–73. The House version was virtually identical to the current CAA section 112(n)(1)(A), and was ultimately adopted by the conference committee, enacted by Congress and signed into law. According to the commenter, Congress expressly rejected the "list-under-(c)-and-regulate-under-(d)" approach that S. 1630 would have applied to EGUs, and that Congress did choose to apply to other source categories. The commenter stated that the EPA's interpretation that the Agency is "required to establish emission standards for EGUs consistent with the requirements set forth in section 112(d)" (Id. at 24,993/3) fails to take the legislative history into account, and in a footnote, the commenter states that the Agency erred by not addressing the legislative history as it did in the 2005 action.

Response: For the reasons stated above, we believe commenter's reliance on the single statement of one legislator is flawed. In addition, in a footnote the commenter stated that the EPA recognized "that it had to address" the legislative history in its 2005 action, and that the EPA erred in this case because we did not address the legislative history. The commenter cites no case law to support its contention that an Agency must "address" unpersuasive legislative history. Further, in the 2005 action, the EPA relegated to a footnote the Oxley statement that commenter relies on so heavily even though the statement supported the interpretation we provided in that rule. We recognized then what the commenter fails to recognize now, which is that the Agency cannot argue that the meaning of CAA section 112(n)(1)(A) is clear based on the statements of one legislator.

Furthermore, the Agency's interpretation does not violate Chevron Step 1. The terms "appropriate" and "necessary" are ambiguous. The statements of a lone legislator do not transform those ambiguous words into a Chevron Step 1 situation.

Moreover, the commenter's assertion that Congress unambiguously defined the factors to consider in making the appropriate determination is without merit. We fully explain in the preamble to the proposed rule the basis for the Agency's interpretation, and we are not revising that interpretation based on the comments received.

Finally, the EPA notes that the sentence concerning regulation under CAA section 112(d) that the commenter quotes from the preamble states, in full: "Congress did not exempt EGUs from the other requirements of section 112 and, *once listed*, the EPA is required to establish emission standards for EGUs consistent with the requirements set forth in section 112(d), as described above." 76 FR 24993 (*emphasis added*). The EPA discusses requirements to regulate section 112(c) listed sources under section 112(d) in response to other comments.

c. Consideration of Both Environmental Effects and Health Effects From Other Sources

Comment: Several commenters stated that the EPA acts contrary to congressional intent when the Agency considers itself "thereby authorized to consider 'environmental effects' and the effects of HAP emissions from non-EGU sources, in making its 'appropriate and necessary' finding under subparagraph (n)(1)(A)."

Commenters assert that the EPA misreads CAA section 112(n)(1)(B) and (C) to inject environmental effects in the CAA section 112(n)(1)(A) determination. According to one commenter the plain language of CAA section 112(n)(1) establishes that regulation of EGUs is to be predicated solely on "hazards to public health" attributable to HAP emissions. The legislative history providing that the EPA "may regulate [EGUs] only if the studies described in section 112(n) clearly establish that emissions of any pollutant * * * from such units cause a significant risk of serious adverse risk to the public health" confirms that plain language. *See* Oxley Statement at 1416–17. The commenter further stated that nothing on the face of CAA section 112(n)(1)(A) indicates that Congress intended that the EPA should (or must) take into account any additional information that might be developed through the other studies mentioned in subparagraphs (n)(1)(B) and (C) (*i.e.*, the Mercury Study [56] and the NAS Study [57]), such as HAP emissions from non-EGU sources. The commenter also identified other provisions of section 112 that specifically require consideration of environmental effects and states that Congress would have requires such consideration in CAA section 112(n)(1) if it had wanted EPA to consider environmental effects.

The commenter makes a related assertion that the EPA acts contrary to congressional intent by assuming authority to assess the "'hazard to public health or the environment [from] HAP emissions from EGUs alone' or the 'result of HAP emissions from EGUs in conjunction with HAP emissions from other sources'" (citing 76 FR at 24,988/1). According to the commenter, the only evident basis for the Agency's interpretation that, in making its "appropriate and necessary" finding, the EPA can (and should) take into account HAP emissions from sources other than EGUs, is that the Mercury Study authorized by CAA 112(n)(1)(B) references "mercury emissions from * * * municipal waste combustion units, and other sources, including area sources," in addition to EGUs. The commenter asserts, however, that subparagraph (n)(1)(A) identifies the Utility Study as the sole study to inform EPA's "appropriate and necessary" finding. The commenter states that if Congress had intended that the EPA take into account information developed through the Mercury Study, Congress "would not have specified that the EPA was to predicate its 'appropriate and necessary' finding on the 'results of the study required by this subparagraph' (n)(1)(A)."

Commenter also cites to a number of other section 112 provisions that expressly address environmental effects and the commenter states the only conclusion to draw from the inclusion in those provisions and the absence of such language in section 112(n)(1)(A) is that Congress intended public health to be the only basis for the appropriate and necessary finding.

[56] U.S. EPA. 1997. *Mercury Study Report to Congress.* EPA–452/R–97–003. December.

[57] NAS, 2000.

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Response: The commenter again relies in part on the statements of one legislator to attack EPA's reasoned interpretation of an ambiguous statute. To the extent the commenter's arguments rely on this limited evidence, we refer to the response above. As we stated above, CAA section 112(n)(1) is an ambiguous statutory provision; thus, the EPA's interpretation, not commenter's, is entitled to considerable deference if it is a reasonable reading of the statute. *Chevron,* 467 U.S. at 843–44. For the reasons described herein and in the proposal, we believe that we have reasonably interpreted the statutory terms at issue here. The Agency directs attention to section III.A. of the proposed rule, which includes a thorough discussion of the Agency's interpretation of the relevant statutory terms. To the extent the commenters disagree with EPA's interpretations, the EPA refers back to its discussion in the proposal and responds to the comments as follows.

The commenter appears to maintain that the EPA must interpret the scope of the appropriate and necessary finding solely in the context of the CAA section 112(n)(1)(A) Utility Study, such that only hazards to public health and only EGU HAP emissions may be considered. The commenter incorrectly conflates the requirements for the Utility Study with the requirement to regulate EGUs under CAA section 112 if EPA determines it is appropriate and necessary to do so. The commenter concedes that the Agency may consider information other than that contained in the Utility Study, but only to the extent it relates specifically to hazards to public health directly attributable to HAP emissions from EGUs. We agree that we may consider additional information other than that contained in the Utility Study, as we stated in the preamble to the proposed rule, because courts do not interpret phrases like "after considering the results of" in a manner that precludes the consideration of other information. *See United States* v. *United Technologies Corp.,* 985 F.2d 1148, 1158 (2nd Cir. 1993) ("based upon" does not mean "solely);[58] *see also* 76 FR 24988. We further explained in the preamble to the proposed rule that it was reasonable to interpret the scope of the appropriate and necessary finding in the context of all three studies required under CAA section 112(n)(1) because the provision is title "Electric utility steam generating units."[59] The commenter has provided little more than unpersuasive legislative history to support its restrictive interpretation of our authority. *Id.*

The commenter also argues that the statute clearly prohibits the Agency from considering adverse environmental effects or the cumulative effects of HAP emissions from EGUs and other sources based on its claim that the statute is clear when one *properly* considers the legislative history. Again, the commenter has provided no support for its contention other than the statements of one Representative and the improper conflation of the CAA section 112(n)(1)(A) direction on the conduct of the Utility Study and the appropriate and necessary finding. Congress left it to the Agency to determine whether it is appropriate and necessary to regulate EGUs under CAA section 112 and the statute does not limit the Agency to considering only hazards to public health and only harms directly and solely attributable to EGUs.

The commenter stated that Congress specifically told EPA when it wanted EPA to consider adverse environmental effects in CAA section 112 and cites to several provisions of the Act that require consideration of adverse environmental effects. The commenter ignores CAA section 112(n)(1)(B), which directs the Agency to consider adverse environmental effect. In any event, even were we to view section 112(n)(1)(A) in isolation, as the commenter suggests, we still maintain that we can consider adverse environmental effects under 112(n)(1)(A). Nothing in section 112(n)(1)(A) precludes consideration of environmental effects. Congress required the Agency to assess whether it is appropriate and necessary to regulate EGUs under section 112. We believe that adverse environmental effects can be considered in the appropriate analysis. Congress specifically directed the Agency to consider adverse environmental effects when delisting source categories pursuant to section 112(c)(9), and thus we believe it is reasonable to consider such effects when determining whether it is appropriate to regulate such units under section 112, especially given that Congress did not limit our appropriate and necessary inquiry to the Utility Study. See CAA section 112(c)(9)(B)(ii).

Moreover, the other provisions of CAA section 112 that specifically discuss environmental effects have purposes that are distinguishable from CAA section 112(n)(1), and we do not believe one can reasonably draw the conclusion that the commenter does when comparing those provisions to CAA section 112(n)(1)(A). The lack of a requirement to consider environmental effects in CAA section 112(n)(1)(A) does not equate to a prohibition on the consideration of environmental effects as the commenter concludes. The EPA maintains that it reasonably concluded that we should protect against identified or potential adverse environmental effects absent clear direction to the contrary.

Concerning the consideration of the cumulative effect of HAP emissions from EGUs and other sources, we provided a reasonable interpretation of the statute and noted that our interpretation, unlike commenters, does not "ignore the manner in which public health and the environment are affected by air pollution. An individual that suffers adverse health effects as the result of the combined HAP emissions from EGUs and other sources is harmed, irrespective of whether HAP emissions from EGUs alone would cause the harm."[60]

d. Finding for All HAP To Be Regulated

Comment: Several commenters stated that for those EGU HAP for which the Agency makes no CAA section 112(n)(1)(A) determination, their regulation under CAA section 112 is not authorized. For example, one commenter maintains that the Agency could regulate HAP emissions from EGUs under CAA section 112(n). Accordingly, to the extent that the EPA reads CAA section 112, as construed by *National Lime Ass'n,* as compelling it to regulate all HAP emitted by EGUs, should the Agency make an "appropriate and necessary" determination under CAA section 112(n)(1)(A) with respect to a single HAP (*e.g.,* Hg), the EPA stands poised to commit a fundamental legal error that will condemn the final rule on review. Cf., *e.g., PDK Laboratories, Inc.,* 362 F.3d at 797–98; *Holland* v. *Nat'l Mining Ass'n,* 309 F.3d at 817 (where an agency applies a Court of Appeals "interpretation * * * because it believed that it had no choice" and that it "was effectively 'coerced' to do so," then the agency "cannot be deemed to have exercised its reasoned judgment").

Response: We do not agree with the commenter's assertion that Congress intended EPA to regulate only those EGU HAP emissions for which an appropriate and necessary finding is

[58] Several commenters have taken issue with our citation to *United States* v. *United Technologies Corp.* because the language at issue in that case was "based upon" and the language of section 112(n)(1)(A) is "after considering the results of." We believe that, if anything, "based upon" is more prescriptive than "after considering the results of" such that the case supports the Agency's interpretation that additional information other than the Utility Study may be considered in making the appropriate and necessary finding.

[59] 76 FR 24986–87.

[60] 76 FR 24988.

made, and the commenter has cited no provision of the statute that states a contrary position. The EPA reasonably concluded that we must find it "appropriate" to regulate EGUs under CAA section 112 if we determine that a single HAP emitted from EGUs poses a hazard to public health or the environment. If we also find that regulation is necessary, the Agency is authorized to list EGUs pursuant to CAA section 112(c) because listing is the logical first step in regulating source categories that satisfy the statutory criteria for listing under the statutory framework of CAA section 112. *See New Jersey,* 517 F.3d at 582 (stating that "[s]ection 112(n)(1) governs how the Administrator decides whether to list EGUs. * * *"). As we noted in the preamble to the proposed rule, D.C. Circuit precedent requires the Agency to regulate all HAP from major sources of HAP emissions once a source category is added to the list of categories under CAA section 112(c). *National Lime Ass'n* v. *EPA,* 233 F.3d 625, 633 (D.C. Cir. 2000). 76 FR 24989.

The commenter does not explain its issues with our interpretation of how regulation under section 112 works—*i.e.* making a determination that a source category should be listed under CAA section 112(c), listing the source category under CAA section 112(c), regulating the source category under CAA section 112(d), and conducting the residual risk review for sources subject to MACT standards pursuant to CAA section 112(f). Instead, it asserts that our decision is flawed because the interpretation we provided does not account for all the alternatives for regulating EGUs under section 112, and that we have not properly exercised our discretion leading to a fatal flaw in our rulemaking.

The commenter also ignores the language of section 112(n)(1)(A). As explained in the proposed rule, the use of the terms section, subsection, and subparagraph in section 112(n)(1)(A) demonstrates that Congress was consciously distinguishing the various provisions of section 112 in directing EPA's action under section 112(n)(1)(A). Congress directed the Agency to regulate utilities "under this section," not "under this subparagraph," and accordingly EGUs should be regulated under section 112 in the same manner as other categories for which the statute requires regulation. Furthermore, the D.C. Circuit Court found that section 112(n)(1) "governs how the Administrator decides whether to list EGUs" and that once listed, EGUs are subject to the requirements of section 112. *New Jersey,* 517 F.3d at 583. Indeed, the D.C. Circuit Court expressly noted that "where Congress wished to exempt EGUs from specific requirements of section 112, it said so explicitly," noting that "section 112(c)(6) expressly exempts EGUs from the strict deadlines imposed on other sources of certain pollutants." *Id.* Congress did not exempt EGUs from the other requirements of section 112, and once listed, the EPA is reasonably regulating EGUs pursuant to the standard-setting provisions in section 112(d), as it does for all other listed source categories.

The commenter provided no alternative theory for regulating EGUs under CAA section 112, other than to state that the EPA could regulate under CAA section 112(n)(1). However, even assuming for the sake of argument, that we could issue standards pursuant to CAA section 112(n)(1), we would decline to do because there is nothing in section 112(n)(1)(A) that provides any guidance as to how such standards should be developed. Any mechanism we devised, absent explicit statutory support, would likely receive less deference than a CAA section 112(d) standard issued in the same manner in which the Agency issues standards for other listed source categories. We would also decline to establish standards under section 112(n)(1) because Congress did provide a mechanism under CAA sections 112(d) and (f) for establishing emission standards for HAP emissions from stationary sources and it is reasonable to use that mechanism to regulate HAP emissions from EGUs.

e. Considering Costs in Finding

Comment: Several commenters assert that the EPA must consider costs in assessing whether regulation of EGUs is appropriate under CAA section 112(n)(1)(A). Commenters posit that the EPA's position that "the term 'appropriate' * * * does not allow for the consideration of costs in assessing whether hazards * * * are reasonably anticipated to occur based on EGU emissions," 76 FR at 24,989/1, does not withstand scrutiny. According to the commenters, the treatment of "costs" under section 112(c) does not support the Agency's position, and the process by which sources may be "delisted" under section 112(c)(9), including no consideration of costs, sheds no light on the circumstances under which it may be "appropriate" to regulate EGUs under section 112(n)(1)(A).

Commenters characterize as "unintelligible" the EPA's position that it is "reasonable to conclude that costs may not be considered in determining whether to regulate EGUs" when "hazards to public health and the environmental are at issue (citing 76 FR at 24989). "Two commenters stated that a natural reading of the term "appropriate" would include the consideration of costs. According to the commenters, something may be found to be "appropriate" where it is "specially suitable," "fit," or "proper." *See* Webster's Third New International Dictionary at 106 (1993). The term "appropriate" carries with it the connotation of something that is "suitable or proper in the circumstances." *See* New Oxford American Dictionary (2d Ed. 2005). Considering the costs associated with undertaking a particular action is inextricably linked with any determination as to whether that action is "specially suitable" or "proper in the circumstances." One commenter notes that in 2005 (70 FR 15994, 16000; March 29, 2005) the EPA used the dictionary definition of "appropriate," as being "especially suitable or compatible" and that it would be difficult to fathom how a regulatory program could be either "suitable" or "compatible" for a given public health objective without consideration of cost.

One commenter asserts that on the face of CAA section 112(n)(1)(A), it is clear that the EPA is expected to consider costs. According to the commenter, that Congress intended that the EPA investigate and consider "alternative control strategies" for emissions as part of the section 112 (n)(1) Utility Study when making the "appropriate and necessary" determination refutes the notion that the Agency can, and indeed must, disregard the cost of regulation in making that determination, because the cost of a given emission "control strategy" is a central factor in any evaluation of "alternative" controls.

Further, according to commenters, it is well-settled that CAA regulatory provisions should be read with a presumption in favor of considering costs (citing *Michigan* v. *EPA,* 213 F.3d 663, 678 (D.C. Cir. 2000)), and the legislative history of section 112(n)(1)(A) confirms that Congress intended EPA to consider costs (citing Oxley Statement at 1417).

Commenters also assert that the EPA falsely represents that it "did not consider costs when making the "appropriate" determination in the EPA's December 2000 notice (76 FR at 24,989/2).

Response: The commenters first take issue with EPA's explanation of why the Agency determined that costs should not be considered in making the appropriate determination. What

commenters do not identify is an express statutory requirement that the Agency consider costs in making the appropriate determination. Congress treated the regulation of HAP emissions differently in the 1990 CAA amendments because the Agency was not acting quickly enough to address these air pollutants with the potential to adversely affect human health and the environment. *See New Jersey,* 517 F.3d at 578. Specifically, following the 1990 CAA amendments, the CAA required the Agency to list source categories and nothing in the statute required us to consider costs in those listing decision, and we have not done so when listing other source categories. Thus, it is reasonable to make the listing decision, including the appropriate determination, without considering costs.

The commenters next argue that the Agency is compelled by the statute to consider costs based on a dictionary definition of "appropriate" and the CAA section 112(n)(1)(A) direction to consider alternative control strategies for regulating HAP emissions in the Utility Study.

Concerning the definition of "appropriate", commenters stated:

> Not only is it "reasonable" for EPA to consider costs in determining whether it is "appropriate" to regulate EGU HAP emissions, a natural reading of the term indicates that excluding the consideration of costs would be entirely unreasonable. Something may be found to be "appropriate" where it is "specially suitable," "fit," or "proper." *See* Webster's Third New International Dictionary at 106 (1993). The term "appropriate" carries with it the connotation of something that is "suitable or proper in the circumstances." *See* New Oxford American Dictionary (2d Ed. 2005) at 76. Considering the costs associated with undertaking a particular action is inextricably linked with any determination as to whether that action is "specially suitable" or "proper in the circumstances."

The EPA believes the definition of "appropriate" that the commenters provide wholly support its interpretation and nothing about the definition compels a consideration of costs. It is appropriate to regulate EGUs under CAA section 112 because EPA has determined that HAP emissions from EGUs pose hazards to public health and the environment, and section 112 is "specially suitable" for regulating HAP emissions, and Congress specifically designated CAA section 112 as the "proper" authority for regulating HAP emissions from stationary sources, including EGUs. Section 112 of the CAA is "suitable [and] proper in the circumstances" because EPA has identified a hazard to public health and the environment from HAP emissions from EGUs and Congress directed the Agency to regulate HAP emissions from EGUs under that provision if we make such a finding. Cost does not have to be read into the definition of "appropriate" as commenter suggests. In addition, as stated elsewhere in response to comments, the Agency does not consider costs in any listing or delisting determinations, and the EPA maintains that it is reasonable to assess whether to list EGUs (*i.e.* the appropriate and necessary finding) without considering costs.

The commenters' argument that costs must be considered based on the CAA section 112(n)(1)(A) requirement to "develop and describe alternative control strategies" in the Utility Study is equally flawed. The argument is flawed because Congress did not direct the Agency to consider in the Utility Study the costs of the controls when evaluating the alternative control strategies. In addition, the EPA did not consider the costs of the alternative controls in the Utility Study, as implied by the commenter. Thus, even viewing section 112(n)(1)(A) in isolation, there is nothing in that section that compels EPA to consider costs. For the reasons described herein, we do not believe that it is appropriate to consider costs in determining whether to regulate EGUs under section 112.

Additionally, one commenter attempts to refute EPA's statement in the preamble to the proposed rule that the EPA did not consider costs in the 2000 finding by pointing to the only two mentions of cost in that notice. However, the EPA did not say that costs were not mentioned in the 2000 finding and a review of the regulatory finding will show that costs were not considered in the regulatory finding. 65 FR 79830 (December 20, 2000) ("Section III. What is EPA's Regulatory Finding?").

f. Considering Requirements of the CAA in "Necessary"

Comment: Several commenters disagree with EPA's position that it need consider "only those requirements that Congress directly imposed on EGUs through the CAA as amended in 1990," for which "EPA could reasonably predict HAP emission reductions at the time of the Utility Study." According to the commenters, the statutory language of CAA section 112(n)(1) requires that the EPA consider the scope and effect of EGU HAP emissions after the imposition of all of the "requirements" of the CAA, not just the Acid Rain program. The commenter maintains that it would have been easy enough for Congress in subparagraph 112(n)(1)(A) to specify "after imposition of the requirements of Title IV of this chapter," but Congress did not. The commenters further add that the legislative history confirms that Congress meant something much broader than that, providing that the EPA is authorized to regulate EGUs under CAA section 112 only after "taking into account compliance with all provisions of the act and any other Federal, State, or local regulation and voluntary emission reductions." The commenters stated that the CAA's "requirements" include the submission by states of ozone and fine PM attainment demonstrations, as well as SIP provisions needed to reach attainment of the NAAQS because such provisions could include controls on EGUs to reduce SO_2 and NO_X, which controls could also result in a reduction in Hg emissions.

Response: The commenter's characterization of the facts is flawed and its reliance on legislative history that is in direct conflict with the express terms of the statute is unpersuasive.

On the facts, the EPA explained in the preamble to the proposed rule its interpretation of the phrase "after imposition of the requirements of [the Act]" as it related to the conduct of the Utility Study.[61] We reasonably concluded that, since Congress only provided 3 years after enactment to conduct the study, the phrase referred to requirements that were directly imposed on EGUs through the CAA amendments and for which the Agency could reasonably predict co-benefit HAP emission reductions. *Id.* The EPA did not state that the phrase only applied to the Acid Rain program, as commenter asserts, and the Utility Study in fact discussed other regulations, including the NSPS for EGUs and revised NAAQS. With regard to the latter, the EPA ultimately determined that it could not sufficiently quantify the reductions that might be attributable to the NAAQS because states are tasked with implementing those standards. *See* Utility Study, pages ES–25, 1–3, 2–32. Conversely, commenter's position is that the EPA must consider implementation of *all* the requirements of the CAA, but it does not indicate how in conducting the Utility Study the Agency could have possibly considered co-benefit HAP reductions attributable to all future CAA requirements. The Agency appropriately considered the other requirements of the Act in the Utility Study and considered those requirements in determining that it was

[61] 76 FR 24990.

necessary to regulate coal- and oil-fired EGUs in December 2000.

Although not required, the Agency in the preamble to the proposed rule conducted further analyses in support of the 2000 finding. In doing so, we considered a number of requirements that far exceed what Congress contemplated when enacting CAA section 112(n)(1)(A)), and our analyses still show that it remains necessary to regulate coal- and oil-fired EGUs under section 112. 76 FR 24991.

We maintain that we have reasonably interpreted the requirement to consider the hazards to public health and the environment reasonably anticipated to occur after imposition of the requirements of the Act as explained in the preamble to the proposed rule.[62] In addition, as stated above, we also believe it would be reasonable to find it necessary to regulate HAP emissions from EGUs based on our finding that such emissions pose a hazard to public health and the environment today without considering future reductions that we currently project to occur as the result of imposition of CAA requirements that are not yet effective (*e.g.,* CSAPR).

Moreover, Representative Oxley's statement cited by the commenter is not consistent with the express terms of CAA section 112(n)(1)(A) on this issue. Representative Oxley stated that the EPA was to take "into account compliance with all the provisions of the act and any other Federal, State, or local regulation and voluntary emission reductions," but CAA section 112(n)(1)(A) directs the Agency to consider "imposition of the requirements of this chapter," which means the CAA. The Agency reasonably focused on the requirements of the Clean Air Act, which are federally enforceable, and declined to include potential future reductions that may be attributable to voluntary emission reduction programs or state and local regulations that have no basis in the Clean Air Act and are not federally enforceable. In addition to the statutory direction not to consider such requirements, the EPA believes it is reasonable not to include potential reductions attributable to such requirements because the Agency cannot assure that such requirements and the attendant HAP reductions will remain absent regulation under section 112. Finally, the commenter implies that EPA's position is that the Agency will only consider requirements of the Act that directly regulate HAP emissions. The EPA never stated or suggested that interpretation and a fair reading of the proposed rule will demonstrate that EPA considered requirements that achieve co-benefit HAP emission reductions, for example the Transport Rule (known as CSAPR).

Comment: One commenter stated that, under CAA section 112, regulating EGUs is permissible only insofar as it is focused, targeted, and predicated on concrete findings by the Agency that such regulation is indeed "necessary." According to the commenter, the EPA construes CAA section 112(n)(1)(A) as permitting it to find that it is "necessary" to regulate EGUs even where the Agency does not actually know whether it is "necessary" to regulate EGUs. Citing the D.C. Circuit, the EPA suggests that "'there are many situations in which the use of the word 'necessary,' in context, means something that is done, regardless of whether it is indispensible,'" in order to "'achieve a particular end.'" 76 FR 24990, quoting *Cellular Telecommunications* v. *FCC,* 330 F.3d 502, 510 (D.C. Cir. 2003). The commenter stated that in the "context" of CAA section 112(n)(1)(A), as informed by the relevant legislative history from Representative Oxley, it is clear that regulation of EGU HAP emissions can be considered "necessary" only if EPA were to "clearly establish" that such regulation was effectively "indispensible" to address the identified harm. As EPA concedes that it has made no such determination here, its proposal is fatally flawed for that reason alone.

The commenter further asserts that the EPA erred when it concluded that it may " 'determine it is necessary to regulate under section 112' when the Agency is 'uncertain whether imposition of the requirements of the CAA will address the identified hazards'" (citing 76 FR at 24,991/3). According to the commenter, the EPA "cannot take refuge in its own 'uncertainty' to support a finding that it is 'necessary' to regulate EGUs under section 112, and the Act precludes the EPA from "'err[ing] on the side of regulation'" in face of uncertainty (*id.*). The commenter also implies that the finding was based on non-HAP emissions.

Response: The commenter again relies on the legislative statements of one Representative and asserts that the statements are controlling. The EPA disagrees with commenter and maintains that its interpretation of the term "necessary" is reasonable. 76 FR 24990–92 (Section III.A.2.b of the preamble to the proposed rule contains the EPA's interpretation of the term "necessary".) 76 FR 24990–92 (Section III.A.2.b of the proposed rule contains EPA's interpretation of the term "necessary".) The commenter also, in a footnote, implies that EPA based the appropriate and necessary finding on non-HAP air pollution. The commenter is wrong as explained in more detail above.

As an initial matter, this comment is only addressing one aspect of the Agency's interpretation of the term necessary. As EPA stated at proposal:

> If we determine that the imposition of the requirements of the CAA will not address the identified hazards, EPA must find it necessary to regulate EGUs under section 112. Section 112 is the authority Congress provided to address hazards to public health and the environment posed by HAP emissions and section 112(n)(1)(A) requires the Agency to regulate under section 112 if we find regulation is "appropriate and necessary." If we conclude that HAP emissions from EGUs pose a hazard today, such that it is appropriate, and we further conclude based on our scientific and technical expertise that the identified hazards will not be resolved through imposition of the requirements of the CAA, we believe there is no justification in the statute to conclude that it is not necessary to regulate EGUs under section 112.

76 FR 24991.

The EPA has determined that the imposition of the requirements of the CAA will not address the hazards to public health or hazards to the environment that EPA has identified; therefore, it is necessary to regulate EGUs under CAA section 112.

The EPA further interpreted the statute to allow the Agency to find that it is necessary to regulate EGUs under other circumstances, and it is with one of our additional interpretations that commenter takes issue. Specifically, the commenter argues that EPA's interpretation authorizes the Agency to find it necessary to regulate EGUs when we are uncertain it is necessary, but that misconstrues our interpretation and the record. At proposal, the EPA stated:

> In addition, we may determine it is necessary to regulate under section 112 even if we are uncertain whether the imposition of the requirements of the CAA will address the identified hazards. Congress left it to EPA to determine whether regulation of EGUs under section 112 is necessary. We believe it is reasonable to err on the side of regulation of such highly toxic pollutants in the face of uncertainty. Further, if we are unsure whether the other requirements of the CAA will address an identified hazard, it is reasonable to exercise our discretion in a manner that assures adequate protection of public health and the environment. Moreover, we must be particularly mindful of CAA regulations we include in our modeled estimates of future emissions if they are not

[62] 76 FR 24990.

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final or are still subject to judicial review ([*e.g.*], the Transport Rule). If such rules are either not finalized or upheld by the Courts, the level of risk would potentially increase. *Id.*

The CAA requires EPA to exercise its discretion in determining whether regulation under section 112 is necessary, and the D.C. Circuit has stated that "there are many situations in which the use of the word 'necessary,' in context, means something that is done, regardless of whether it is indispensible, to achieve a particular end." *See Cellular Telecommunications & Internet Association, et al.* v. *FCC,* 330 F.3d 502, 510 (D.C. Cir. 2003). The EPA's interpretation of "necessary" is reasonable in the context of CAA section 112(n)(1)(A).

The commenter stated that EPA concedes that the Agency has not "clearly established" that regulation of HAP emissions under CAA section 112 is "indispensible." The EPA has conceded nothing but, more importantly, the supposed standard that the commenter presents for evaluating whether it is necessary to regulate HAP emissions from EGUs is not required by the statute. Even the limited legislative history on which the commenter incorrectly relies does not espouse such a standard. The commenter specifically takes issue with EPA's statement that the Agency may find it is necessary to regulate EGUs under CAA section 112 if we are "uncertain whether imposition of the other requirements of the CAA will sufficiently address the identified hazards." 76 FR at 24990. The commenter has again misinterpreted the Agency's position by stating that "EPA construes CAA section 112(n)(1)(A) as permitting it to find that it is "necessary" to regulate EGUs even where the Agency does not actually know whether it is "necessary" to regulate EGUs." Instead, the EPA maintains that it may be necessary to regulate EGUs under CAA section 112 if we identify a hazard to public health or the environment that is appropriate to regulate today and our projections into the future do not clearly establish that the imposition of the requirements of the CAA will address the identified hazard in the future. Making a prediction about future emission reductions from a source category is difficult for statutory provisions that do not mandate direct control of the given source category or pollutants of concern. We maintain that erring on the side of caution is appropriate when the protection of public health and the environment from HAP emissions is not assured based on our modeling of future emissions.

Furthermore, as we stated in the preamble to the proposed rule, we believe it would be reasonable to find it appropriate *and* necessary to regulate EGUs under section 112 today based on a determination that HAP emissions from EGUs pose a hazard to public health and the environment without considering future HAP emission reductions. 76 FR 24991, n.14. We maintain this is reasonable because "Congress could not have contemplated in 1990 that EPA would have failed in 2011 to have regulated HAP emissions from EGU's where hazards to public health and the environment remain." *Id.* The phrase "after imposition of the requirements of [the Act]" as contemplated CAA section 112(n)(1)(A) could be read to apply only to those requirements clearly and directly applicable to EGUs under the 1990 CAA amendments, all of which have been implemented and still hazards to public health and the environment from HAP emissions from EGUs remain.

g. Listing EGUs Under 112

Comment: One commenter stated that even if EPA were to establish under CAA section 112(n)(1)(A) that it is "appropriate and necessary" to regulate HAP emissions from EGUs, regulating those emissions in the form of a MACT standard established pursuant to CAA section 112(d) is contrary to the plain language of the Act. According to the commenter, if EPA proceeds to finalize the proposal and adopts such a standard, the rule will for this reason alone be "dead-on-arrival". According to the commenter, the EPA apparently believes that its only option in regulating EGU HAP emissions is establishing a MACT standard under CAA section 112(d). In the preamble to its proposal, the commenter states that EPA contends that, "once the appropriate and necessary finding is made," EGUs are then "subject to section 112 in the same manner as other sources of HAP emissions"—*i.e.,* by "listing" EGUs under CAA section 112(c) and adopting a MACT standard under CAA section 112(d). *See* 76 FR 24993/2 (emphasis added). The commenter further stated that, given that Congress "directed the Agency to regulate utilities 'under this section' [*i.e.,* CAA section 112]," EPA continues, it follows that "EGUs should be regulated in the same manner as other categories for which the statute requires regulation." Id. (emphasis added). The commenter asserts that as EPA sees it, because "Congress did not exempt EGUs from the other requirements of section 112," once EGUs were "listed" under CAA section 112(c), the Agency was "required to establish emission standards for EGUs consistent with the requirements set forth in section 112(d)." Id. at 24,993/3 (emphasis added).

The commenter stated that, in support of this reading of the CAA, the EPA invokes the decision of the U.S. Court of Appeals for the D.C. Circuit in *New Jersey* v. *EPA,* 517 F.3d 574 (D.C. Cir. 2008). The commenter further alleged that, according to EPA, the D.C. Circuit has "already held that section 112(n)(1) 'governs how the Administrator decides whether to list EGUs.'" *See* 76 FR 24993/2–3, quoting 517 F.3d at 583. The commenter stated that EPA construes that holding as indicating that, "once listed, EGUs are subject to the requirements of section 112"—including, the EPA presumes, CAA section 112(d). Id. The commenter stated that elsewhere, the EPA construes CAA section 112(n)(1) (A) as "govern[ing] how the Administrator decides whether to list EGUs for regulation under section 112," and quotes the D.C. Circuit's observation in *New Jersey* that "Section 112(n)(1) governs how the Administrator decides whether to list EGUs; it says nothing about delisting EGUs." *See* 76 FR 24981/2, quoting 517 F.2d at 582.

The commenter asserts that EPA misinterprets the "under this section" language of CAA section 112(n)(1); overstates the significance of the *New Jersey* decision; and, as a consequence, misapprehends the scope of its own discretion to formulate regulatory standards for EGUs under CAA section 112. In light of these errors, the commenter maintains that EPA should withdraw the proposed MACT rule.

One commenter stated that if Congress had intended that EPA regulate EGU HAP emissions only through a MACT standard, Congress could have—and presumably would have—directed the Agency to regulate EGU emissions "under CAA section 112(d)." Thus, the commenter maintained that EPA's authority to regulate EGU HAP emissions is not derived from any particular subsection of CAA section 112. Rather, the commenter stated that EPA is authorized to regulate "under this section"—*i.e.,* CAA section 112 generally—as may be "appropriate and necessary." The commenter stated that there is nothing on the face of CAA section 112(n)(1)(A) that specifies that regulation of EGUs must occur under CAA section 112(d). To the contrary, according to the commenter, a plain reading of CAA section 112(n)(1)(A), as interpreted based on the Oxley statement, indicates that establishing a

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MACT standard for EGUs under CAA section 112(d) is not what Congress had in mind at all.

Response: We do not agree with the commenter. The EPA interpreted CAA section 112(n)(1)(A) in a manner that gives meaning to all the words used in the provision. *See NRDC* v. *EPA,* 489 F.3d 1364, 1373 (D.C. Cir. 2007) (admonishing EPA for an interpretation of CAA section 112(c)(9) that ignored certain words and the context in which they were used. The Court stated that "EPA's interpretation would make the words redundant and one of them 'mere surplusage,' which is inconsistent with a court's duty to give meaning to each word used by Congress.") (*citing TRW Inc.* v. *Andrews, 534 U.S. 19, 31, 122 S. Ct. 441, 151 L. Ed. 2d 339 (2001)).* Specifically, in the preamble to the proposed rule, we stated:

> The statute directs the Agency to regulate EGUs under section 112 if the Agency finds such regulation is appropriate and necessary. Once the appropriate and necessary finding is made, EGUs are subject to section 112 in the same manner as other sources of HAP emissions. Section 112(n)(1)(A) provision provides, in part, that: '[t]he Administrator shall perform a study of the hazards to public health reasonably anticipated to occur as a result of emissions by electric utility steam generating units of pollutants listed under subsection (b) of this section after imposition of the requirements of this chapter. * * * The Administrator shall regulate electric utility steam generating units *under this section,* if the Administrator finds such regulation is appropriate and necessary after considering the results of the study required *by this subparagraph.*" *Emphasis added.*

In the first sentence, Congress described the study and directed the Agency to evaluate the hazards to public health posed by HAP emissions listed *under subsection* (b) (*i.e.,* CAA section 112(b)). The last sentence requires the Agency to regulate *under this section* (*i.e.,* CAA section 112) if the Agency finds such regulation is appropriate and necessary after considering the results of the study required by this subparagraph (i.e., CAA section 112(n)(1)(A)). The use of the terms "section", "subsection", and "subparagraph" demonstrates that Congress was consciously distinguishing the various provisions of CAA section 112 in directing the conduct of the study and the manner in which the Agency must regulate EGUs if the Agency finds it appropriate and necessary to do so. Congress directed the Agency to regulate utilities "under this section," and accordingly EGUs should be regulated in the same manner as other categories for which the statute requires regulation. *See* 76 FR 24993.

We maintain that our interpretation of the statute gives meaning to all the words, and the commenter's interpretation does not give any particular meaning to the requirement to "regulate under this section [112]". The commenter is correct that Congress could have in CAA section 112(n)(1)(A) directed EPA to regulate HAP from EGUs under CAA section 112(d) after making the appropriate and necessary finding, but the commenter presumes too much when it stated that Congress would have directed the Agency to regulate HAP emissions from EGUs in such a manner if that is what Congress wanted, simply by including the phrase "regulate under this paragraph" or "regulate under this subparagraph" instead of directing the Agency to "regulate under this section". It did not do so.

As we explained in the section II.A. of the proposed rule, CAA section 112 establishes a mechanism to list and regulate stationary sources of HAP emissions. 76 FR 24980–81. Regulation under CAA section 112 generally requires listing under CAA section 112(c), regulation under CAA section 112(d), and, for sources subjected to MACT standards, residual risk regulations under CAA section 112(f) (as necessary to protect human health and the environment with an ample margin of safety). A determination that EGUs should be listed once the prerequisite appropriate and necessary finding is made is wholly consistent with the language of section 112(n)(1)(A), and listed sources must be regulated under CAA section 112(d). *See* CAA section 112(c)(2); *see also New Jersey,* 517 F.3d at 583 (112(n)(1)(A) "governs how the Administrator decides whether to list EGUs").

As noted above, Congress used the terms section, subsection, and subparagraph in section 112(n)(1)(A). The use of these three terms demonstrates that Congress was consciously distinguishing between the various provisions of section 112. Congress directed the Agency to regulate utilities "under this section," and accordingly EGUs should be regulated in the same manner as other categories for which the statute requires regulation.

Furthermore, the flaws in the commenter's interpretation are highlighted by other CAA section 112 provisions wherein Congress provided specific direction as to the manner of regulation. For example, CAA section 112(m)(6) requires the Administrator to determine "whether the other provisions of *this section* [112] are adequate" and also indicates that "[a]ny requirements promulgated pursuant to this *paragraph* * * * shall only apply to the coastal waters of the States which are subject to [section 328 of the CAA]." (*emphasis added*).

In addition, CAA section 112(n)(3) provides that when the Agency is "promulgating any standard under this section [112] applicable to publicly owned treatment works, the Administrator may provide for control measures that include pretreatment of discharges causing emissions of hazardous air pollutants and process or product substitutions or limitations that may be effective in reducing such emissions." Finally, CAA section 112(n)(5) directs the Agency to assess hydrogen sulfide emissions from oil and gas extraction and "develop and implement a control strategy for emissions of hydrogen sulfide to protect human health and the environment * * * *using authorities under [the CAA] including [section 111] of this title and this section [112].*" (*emphasis added*). We believe these provisions provide ample evidence that Congress knew how to alter or caveat regulation under CAA section 112 when that was its intent. For these reasons, we believe commenter's argument is without merit.

Comment: Two commenters stated that CAA section 112(n)(1)(A) does not specify that regulation of EGUs must proceed under CAA section 112(d). According to the commenter, an argument could be made, therefore, that the CAA accords EPA with the discretion to regulate EGUs using strategies other than emission standards in CAA section 112(d). The commenters also state that section 112(n)(1)(A) of the CAA requires that EPA "develop and describe" alternative control strategies for emissions which may warrant regulation under CAA section 112. According to the commenters if Congress meant for EPA to have one sole regulatory option, i.e., regulation of EGUs only under CAA section 112(d), then the development of alternative control strategies would be rendered meaningless because under CAA section 112(d)(3), the EPA is required to determine the level of control that is achieved by the best performing existing units for which it has data and then to impose that level of control on all existing units. The commenter further states that the development of "alternative control strategies" has no role to play in this process. One commenter does note that the consideration of "alternative" controls becomes relevant, if at all, only in those circumstances where EPA might seek to establish a "Beyond-the-Floor" MACT standard pursuant to CAA section 112(d)(2).

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Response: The commenters are correct that CAA section 112(n)(1)(A) directed the Agency to develop and describe in the Utility Study report to Congress alternative control strategies for HAP emissions from EGUs that may warrant regulation in the Utility Study, but the commenters' interpretation of and conclusion based on that language are both factually and legally inaccurate.

The commenters appear to interpret the word "alternative control strategies" to mean something other than the traditional control technologies and control measures that are used to control HAP emissions from EGUs. We do not believe that is a reasonable interpretation of the statute, and the Agency did not interpret the statute in that manner when it conducted the Utility Study. In Chapter 13 of the Utility Study, the EPA considered a range of control measures that would reduce the different types of HAP emitted from EGUs. *http://www.epa.gov/ttn/atw/combust/utiltox/eurtc1.pdf.* The EPA considered pre-combustion controls such as coal washing, fuel switching, and gasification; combustion controls such as boiler design; post-combustion controls such as fabric filters, scrubbers, and carbon absorption; and alternative controls strategies such as demand-side management, energy conservation, and use of alternative fuels (*e.g.*, biomass) or renewable energy. The options discussed in the Utility Study for controlling HAP emissions from EGUs are almost universally available to comply with a CAA section 112(d) standard.

Given the manner in which the Agency conducted the Utility Study, the EPA interpreted the statutory direction as a requirement to set forth the potential alternative control options available to EGUs to comply with CAA section 112 standards in the event the Agency determined regulation under section 112 was appropriate and necessary. The EPA's development and discussion in the Utility Study of alternative control strategies for complying with the standards would help prepare EGUs to comply with the standards if promulgated. Thus, the EPA interpreted the direction to address control strategies in the Utility Study as a request to identify the controls available to EGUs for addressing HAP emissions, and such information would, of course, be relevant if EPA determined that such emissions warranted regulation under section 112.

Furthermore, the EPA establishes CAA section 112(d) standards for stationary sources and it is the responsibility of the sources to comply with the standards using any mechanism available, including pre-combustion and post-combustion measures. Also, the establishment of a MACT standard under CAA section 112(d)(2) and (3) is a two-step process. In the first step, the Agency establishes a floor based on the performance of the best controlled unit or units. *See* CAA section 112(d)(3). In the second step, the Agency must consider additional measures that may reduce HAP emissions and adopt such measures if reasonable after considering costs and non-air quality health and environmental effects. *See* CAA section 112(d)(2). Under the second step, the Agency can consider any measure that reduces HAP emissions even if no source in the category is employing the option under consideration. So, even under the commenter's flawed interpretation of "alternative control strategies", the direction in CAA section 112(n)(1)(A) is not a "pointless exercise" for the development of CAA section 112(d) standards as the Agency considers relevant technologies and HAP emission reduction approaches in evaluating whether to set a more stringent beyond the floor standard.

Comment: One commenter points to CAA section 307(d)(1)(C) and notes that CAA section 112(n) is listed among the provision for which the rulemaking requirements of CAA 307(d) apply. Commenter maintains that this inclusion creates an expectation under the statute that EPA may establish regulatory standards under CAA 112(n). The commenter points to CAA sections 112 (n)(1), (n)(3), and (n)(5) and states that those provisions specifically discuss regulation under CAA section 112 and that EPA must explain why CAA 307(d)(1)(C) states "any regulation under" CAA 112(n) to defend regulation of utilities under section 112(d). The commenter then implies that EPA erred by not even mentioning this provision at proposal.

The commenter also takes issue with EPA's statement in the proposed rule that "use of the terms section, subsection, and subparagraph" "demonstrates that Congress was consciously distinguishing the various provisions of section 112 in directing the conduct of the study and the manner in which the Agency must regulate EGUs," if EPA determines that it is appropriate and necessary to regulate EGUs. See 76 FR at 24,993/2.

One commenter does not agree with the EPA's finding that the word "subsection" in the first sentence of CAA section 112(n)(1)(A) demonstrates that Congress was consciously distinguishing between the various provisions of CAA section 112 in directing the conduct of the study and the manner in which the Agency must regulate EGUs," were the EPA to "find[ ] it appropriate and necessary to do so." *See* 76 FR 24993/2. According to the commenter, the only evident reason that the word "subsection" is used in the first sentence of CAA section 112(n)(1)(A) is because the reference is made to the "pollutants" which the Utility Study is to address—*i.e.*, the "pollutants" that are emitted by EGUs and which are "listed under subsection (b)" of CAA section 112. Similarly, the word "subparagraph" is used in the last sentence of CAA section 112(n)(1)(A) to identify "the study" which the EPA is directed to undertake by subparagraph (A) of CAA section 112(n)(1)—*i.e.*, the Utility Study. That the last sentence of subparagraph (n)(1)(A) also states that EPA "shall regulate electric utility steam generating units under this section" does not even imply—much less expressly communicate—that regulation "under this section" must mean "regulation under section 112(d)." The commenter stated that Congress was "consciously distinguishing" between the "various provisions of section 112" for the sake of clarity in the drafting of CAA section 112(n).

The commenter also asserts that the EPA mistakenly relies on section 112(c)(6) when the EPA states that "'where Congress wished to exempt EGUs from specific requirements of section 112, it said so explicitly. Congress did not exempt EGUs from the other requirements of section 112,'" and thus the Agency is "'required to establish emission standards for EGUs consistent with the requirements set forth in section 112(d)'" (citing 76 FR at 24,993 (internal quotation omitted)).

According to the commenter, nothing in section 112(c)(6) indicates how (or even whether) EGU HAP emissions should be regulated under section 112; paragraph (c)(6) serves only to reiterate that the regulation of such emissions is to occur (if at all) as is provided by section 112(n)(1). The commenter also asserts that the EPA mistakenly relies on *New Jersey*. According to the commenter, the D.C. Circuit in that case did not indicate that the language of section 112(c)(6) should, or could, be construed to mean that EGUs must be regulated under a MACT standard adopted pursuant to section 112(d).

Response: The commenter makes a number of arguments that appear to take issue with the EPA's determination that EGUs should be regulated under CAA section 112(d) if the Agency determines that regulation of HAP emissions from such units is appropriate and necessary.

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The commenter implies that the EPA erred because alternative mechanisms for regulation of EGUs under CAA section 112 might exist. We do not agree.

The commenter's argument that the EPA erred because we did not explain why section CAA section 307(d)(1)(C) contemplates regulations under CAA section 112(n) is without merit. It is correct that the Agency believes EGUs should be regulated in the same manner as other sources if the appropriate and necessary finding is made because of the structure of CAA section 112. Nothing in CAA section 112(n)(1) requires or implies that the Agency should or must establish standards for EGUs under that provision. Furthermore, unlike CAA sections 112(n)(3) and 112(n)(5) that commenter cites, CAA section 112(n)(1)(A) does not provide any guidance concerning the manner in which EPA is authorized or required to regulate sources under CAA section 112. *See* CAA section 112(n)(3) (specifically authorizing identified control measures and other requirements for consideration in issuing standards under CAA section 112); see also CAA section 112(n)(5) (directing the Agency to develop and implement a control strategy for emissions of hydrogen sulfide using any authority available under the CAA, including sections 112 and 111, if regulation is appropriate). For these reasons, we disagree that any error occurred because we did not specifically discuss in this proposed rule whether we could or should regulate EGUs under CAA section 112(n)(1) instead of CAA section 112(d).[63] The Agency validly listed EGUs in 2000 and listed sources must be regulated pursuant to CAA section 112(d).

Even if we agreed that regulation under CAA section 112(n)(1) was a viable option for EGUs, we would still have listed and regulated EGUs like other sources because CAA section 112(d) provides a statutory framework for regulating HAP emissions from sources and CAA section 112(n)(1) does not. We believe that even if CAA section 112(n)(1) were available to regulate EGUs, there would be sufficient uncertainty about the legal vulnerability of such an approach to caution against employing it. This legal uncertainty would be particularly troubling in light of the fact that we have identified hazards to public health and the environment from HAP emissions from EGUs that warrant regulation, and these regulations are long overdue.

The commenter also takes issue with our statement in the preamble to the proposed rule that the use of the words "section", "subsection", and "subparagraph" in CAA section 112(n)(1)(A) "demonstrates that Congress was consciously distinguishing the various provisions of section 112 in directing the conduct of the study and the manner in which the Agency must regulate EGUs." *See* 76 FR 24993. The commenter appears to make much of our use of the word "must" in that sentence and also states that our interpretation of the significance of the use of the three terms in CAA section 112(n)(1)(A) is flawed because Congress only used the three terms for purposes of clarity. The commenter is incorrect on both points. With respect to the commenter's concern regarding the use of the word "must" in the sentence quoted above, we note that in the next sentence we stated that "Congress directed the Agency to regulate utilities 'under this section,' and accordingly EGUs *should* be regulated in the same manner as other categories for which the statute requires regulation." Id. (*emphasis added*). We were not foreclosing the possibility of any alternative interpretation and our use of the term "must" should not detract from the point we were trying to make. Specifically, we believe that Congress would have directed us to regulate EGUs under CAA section 112(n)(1)(A) if that was its intent and, absent that mandate, the better reading of the statute is the one provided in the preamble to the proposed rule, which is that EGUs should be listed pursuant to CAA section 112(c) and subject to CAA section 112(d) emission standards.

The commenter also stated that the EPA relied on CAA section 112(c)(6) to support a conclusion that EGUs must be regulated under CAA section 112(d). The commenter takes the EPA's statements out of context. The statement in whole read:

> Furthermore, the D.C. Circuit Court has already held that section 112(n)(1) "governs how the Administrator decides whether to list EGUs" and that once listed, EGUs are subject to the requirements of CAA section 112. *New Jersey*, 517 F.3d at 583. Indeed, the D.C. Circuit Court expressly noted that "where Congress wished to exempt EGUs from specific requirements of section 112, it said so explicitly," noting that "section 112(c)(6) expressly exempts EGUs from the strict deadlines imposed on other sources of certain pollutants." *Id.* Congress did not exempt EGUs from the other requirements of CAA section 112, and once listed, EPA is required to establish emission standards for EGUs consistent with the requirements set forth in CAA section 112(d), as described below. *See* 76 FR 24993.

As can be seen from this passage, the Court cited section 112(c)(6) as an example of Congress' intent regarding regulating EGUs under CAA section 112. The commenter cited the last clause of the last sentence of the paragraph quoted above without including the prefatory clause "once listed," and, without that clause, the statement is not fairly characterized. The point the EPA was making in that paragraph is that EGUs are a listed source category and listed sources must be regulated under CAA section 112(d) unless the EPA delists the source category.

Comment: One commenter stated that EPA overstates the significance of the D.C. Circuit's holding in *New Jersey* by suggesting that the decision mandates EGU regulation under CAA section 112(d) because EGUs "remain listed" under CAA section 112(c), *See New Jersey*, 517 F.3d at 582. According to the commenter, the court declined to address the lawfulness of EPA's having "listed" EGUs under CAA section 112(c), leaving that matter to be decided if and when EPA adopted standards for EGUs under CAA section 112. Nowhere in the decision did the D.C. Circuit indicate that EPA must regulate EGUs under CAA section 112(d).

According to the commenter, the EPA must consider both whether the regulation of EGUs is "appropriate and necessary" under section 112(n)(1) and address anew whether the Agency is authorized by section 112 to list EGUs under section 112(c) at all. The commenter asserts that on the face of the proposal, the EPA has not revisited the question whether the "listing" of EGUs under section 112(c) is consistent with congressional intent.

Response: The commenter's arguments are circular and it is difficult to fully determine exactly what its issue is with EPA's listing; however, it appears that the commenter believes that EPA incorrectly relied on the *New Jersey* decision to justify the listing of EGUs. The commenter also appears to argue that the Agency has never explained why it has the authority to list EGUs at all. We disagree.

As stated in the preamble to the proposed rule, CAA section 112(n)(1)(A)

[63] We note that in our January 2004 proposed rule, we solicited comment on whether section 112(n)(1)(A) provided independent authority to regulate EGUs. We received several comments on this issue, and we rejected the concept after reviewing the comments and further considering the language of section 112(n)(1)(A) and the structure of section 112. As such, we proposed and are finalizing that once the Agency determines that it is appropriate and necessary to regulate EGUs under section 112, those sources are listed pursuant to subsection 112(c), as we did in December 2000, and the Agency must set standards for those sources pursuant to section 112(d). See section 112(c) and (d)(1) (requiring establishment of 112(d) standards for listed source categories).

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requires EPA to conduct a study of HAP emissions from EGUs and regulate EGUs under CAA section 112 if we determine that regulation is appropriate and necessary, after considering the results of the study. 76 FR 24981, 24986, and 24998. The only condition precedent to regulating EGUs under CAA section 112 is a finding that such regulation is appropriate and necessary (after conducting and considering the Utility Study), and once that finding is made the Agency has the authority to list EGUs under CAA section 112(c) as the first step in the process of establishing regulations under section 112. The D.C. Circuit agrees with that interpretation of the statute as evidenced by its statement in *New Jersey* that "section 112(n)(1)(A) governs how the Administrator decides whether to list EGUs for regulation under section 112," 517 F.3d at 582, and the Court's statement directly contradicts the commenter's position.

The EPA did not rely on the *New Jersey* decision to justify the appropriate and necessary finding as the commenter suggests. We based the finding in 2000 on the extensive information available to the Agency at the time, and we confirmed the finding in the preamble to the proposed rule based on new information. The commenter had ample opportunity to comment on the appropriate and necessary finding, and it may challenge the basis of the listing (*i.e.* the appropriate and necessary finding) when EPA issues the final standards.

Comment: One commenter believes that the D.C. Circuit will condemn the final rule as a result of EPA's "misapprehension" that upon making an "appropriate and necessary" finding, the Agency is compelled by the CAA to adopt a regulatory standard for EGUs under CAA section 112(d). According to the commenter, a regulation will be invalid if the regulation " 'was not based on the [agency's] own judgment' " but " 'rather on the unjustified assumption that it was Congress' judgment that such [a regulation] is desirable' or required." *See Transitional Hospitals Corp.* v. *Shalala*, 222 F.3d 1019, 1029 (D.C. Cir. 2000), quoting *Prill* v. *NLRB*, 755 F.2d 941, 948 (D.C. Cir. 1985). The commenter further notes that the D.C. Circuit has held that, where an agency wrongly construes a judicial decision as compelling a particular statutory interpretation, and thereby unduly limits the scope of its own discretion, the agency's action cannot be sustained. *See, e.g., Phillips Petroleum Co.* v. *FERC*, 792 F.2d 1165, 1171 (D.C. Cir. 1986). The commenter believes the rule is bound to be rejected and that the EPA should "reconsider the legal interpretations on which it purports to base its rule."

Response: We do not agree that we have improperly interpreted the statute as limiting our discretion in the manner suggested by the commenter. The commenter makes only one specific allegation in this comment and that concerns the Agency's conclusion that it must establish CAA section 112(d) standards for EGUs in light of the *New Jersey* decision. The commenter does not explain why that conclusion is incorrect. As we state above and in the preamble to the proposed rule, because EGUs are a CAA section 112(c) listed source category, the Agency must establish CAA section 112(d) standards or delist EGUs pursuant to CAA section 112(c)(9). *See New Jersey*, 517 F.3d at 582–83 (holding that EGUs remain listed under section 112(c)); *see also* CAA section 112(c)(2) (requiring the Agency to "establish emission standards under subsection [112] (d)" for listed source categories and subcategories); 76 FR 24998–99. We concluded in the preamble to the proposed rule that we could not delist EGUs because our appropriate and necessary analysis showed that EGUs did not satisfy the CAA section 112(c)(9)(B)(i) delisting criteria. *Id.* We did not address in the preamble to the proposed rule whether EGUs satisfied the CAA section 112(c)(9)(B)(ii) criteria because EGUs failed the first prong of the delisting provisions. *Id.* We reach the same conclusion in the final rule and also address the delisting petition submitted by this commenter. Because we cannot delist EGUs, we must regulate them under CAA section 112(d). The commenter has provided no legitimate argument to rebut this conclusion. *See also* previous responses regarding regulation under section 112(n)(1)(A).

Comment: One commenter alleges that EPA impermissibly relied on CAA section 112(c)(9) to interpret "hazards to public health", and argues that the "residual risk" provisions in CAA section 112(f)(2) are more appropriate for the establishment of standards for EGUs. The commenter stated that by using CAA section 112(c)(9)(B)(i) in defining "hazards to public health", the Agency has seized on the one interpretation of the phrase that is surely contrary to congressional intent and, thus, falls outside the permissible range of its interpretative discretion. The commenter maintains that the "delisting" criteria of CAA section 112(c)(9) are simply irrelevant to the decision whether EGU HAP emissions will present any "hazards to public health" sufficient to warrant regulation of those emissions under CAA section 112.

The commenter also argues that Congress intended that EGUs be treated differently from all other "major sources" to which the "delisting" provisions of CAA section 112(c)(9), and the standard-setting provisions of CAA section 112(d) necessarily and automatically apply. Therefore, according to the commenter, the EPA's proposal to utilize the criteria of CAA section 112(c)(9) to inform its findings under CAA section 112(n)(1)(A) treats EGUs exactly the same as all other major source categories, is contrary to congressional intent, and thus unlawful. The commenter goes on to state that in exercising its discretion to define "hazards to public health" as the phrase is used in CAA section 112(n)(1)(A), the EPA would be better served to consider the "residual health risk" provisions of CAA section 112(f)(2). Those provisions provide a better analogy to the establishment of standards for EGUs under CAA section 112 than do the "delisting" criteria of CAA section 112(c)(9).

The commenter believes the category-specific criteria of paragraph (c)(9) are a poor fit for an evaluation of "hazards to public health" that should reasonably include such factors as the affected population, the characteristics of exposure, the nature of the health effects, and the uncertainties associated with the data. The commenter states that, while CAA section 112(n)(1)(A) does not expressly include any requirement that EGU emissions be regulated with an "ample margin of safety," that standard is more appropriate than the "one-in-a-million" cancer risk standard of CAA section 112(c)(9)(B)(i) that EPA proposes to employ.

Response: The commenter acknowledges that EPA has broad discretion to interpret the phrase "hazard to public health" but argues that the one thing we cannot do is use the CAA section 112(c)(9)(B) delisting provisions as a benchmark in making that interpretation. The commenter asserts that the use of the delisting standard is clearly contrary to Congressional intent but it does not provide any substantive rebuttal to our conclusion that the CAA section 112(c)(9) standards reflects the level of hazard which Congress concluded warranted continued regulation. Instead, the commenter reverted to its argument that the statute treated EGUs differently. The EPA views the disparate treatment of EGUs in a different light than commenter. While it is true that Congress established a different

statutory provision governing whether to add EGUs as a regulated source category under section 112, we do not interpret CAA section 112(n)(1)(A) as providing Congressional license to ignore risks that Congress determined warranted regulation for all other source categories. Because CAA section 112(c)(9) defines that level of risk, it is reasonable to consider it when evaluating whether EGU HAP emissions pose hazards to public health.

The commenter also suggests that the "ample margin of safety standard" of CAA section 112(f)(2) is a better fit than the one-in-a-million standard set forth in CAA section 112(c)(9)(B)(1) for evaluating hazards to public health. The commenter asserts that an evaluation of "hazards to public health" should include such factors as the affected population, the characteristics of exposure, the nature of the health effects, and the uncertainties associated with the data. However, the EPA did not rely solely on the delisting provisions for evaluating hazards to public health as commenter suggests. In fact, the EPA considered all of the factors the commenter suggests in making our finding.[64] Thus, we decline to adjust our approach to evaluating hazards to public health and the environment based on the comments.

h. 2000 Finding (and 2005 Delisting)

Comment: Several commenters generally support EPA's 2000 finding that regulating HAP emissions from EGUs under CAA section 112 is "appropriate and necessary." According to the commenters, the 2000 finding was proper under the CAA and within EPA's discretion, well-supported based on sound science available to the Agency at the time on the harm from HAP emitted by EGUs, and no additional information makes the finding invalid. Several commenters cited the conclusions of the Utility Study[65] and Mercury Study,[66] which they assert supported the finding and satisfied the only prerequisite for the finding. One commenter specifically asserted that the 2000 finding was well-supported by the Utility Study's conclusions that (1) there was a link between anthropogenic Hg emissions and MeHg found in freshwater fish, (2) Hg emissions from coal-fired utilities were expected to worsen by 2010, and (3) MeHg in fish presents a threat to public health from fish consumption. One commenter noted that the CAA does not require a conclusive link between HAP emissions and harm. One commenter stated that the CAA grants the Administrator discretion in her finding, and that discretionary decision should not be overly scrutinized, citing court opinion.[67] In support of the finding, one commenter stated that it would not make sense for Congress to limit HAP emissions from small businesses such as dry cleaners but to exempt U.S. EGUs, which are the largest sources of many HAP emissions. One commenter agreed that finding was further supported because numerous control options were available to reduce HAP emissions. One commenter agreed with the 2000 finding that the Agency lacked sufficient evidence to conclude that non-Hg HAP from EGUs posed no hazard.

The commenters who generally supported the 2000 finding also commented on specific aspects of the finding. Several commenters asserted that while the evidence on Hg alone supports the finding, the potential harm from non-Hg HAP further supported the 2000 finding. Several commenters noted that new science continues to support the 2000 finding. Several commenters also stated that the "appropriate" finding was further supported because numerous control options were available at the time of the finding that would reduce HAP emissions. One commenter concurred with EPA that regulating natural gas-fired EGUs was not appropriate and necessary because the impacts due to HAP emissions from such units are negligible based on the results of the Utility Study.

Several commenters addressed the 2005 reversal of the 2000 finding. Several commenters specifically supported the vacatur of the 2005 action. Other commenters asserted that the 2005 action was proper, and that EPA reverted back to the 2000 finding in the proposed rule without adequate explanation or support. Several commenters cited the 2005 action as invalidating the 2000 finding, specifically noting that EPA concluded that "no hazards to public health" remained after accounting for emission reductions under CAIR. These commenters assert that EPA's current position is illegal because EPA took the exact opposite position on the interpretation of the term "necessary" in its 2005 reversal, and, thus, deserves no judicial deference. One commenter stated that in 2005 EPA recognized the potential for excessive regulation created by CAA section 112 and determined that the 2000 finding lacked foundation.

Several commenters generally disagreed with the 2000 finding, with two commenters stating that EPA did not have a rational justification for it and another claiming that it was fraught with misinformation and overestimating assumptions. One commenter claimed that EPA did not explain the terms "appropriate" and "necessary" in the 2000 finding and that the emission control analysis was inadequate. Two commenters stated that the 2000 finding was based on data that was more than 10 years old, which causes serious concern regarding the validity of the findings because technology, the regulatory environment, and the economic climate have evolved. Furthermore, because the Utility Report underestimated emissions controls that EGUs would install by 2010 and additional controls that would be later required by the CSAPR, the basis for EPA's 2000 finding has changed. Several commenters stated that a "plausible link" between anthropogenic Hg and MeHg in fish is not an adequate reason for the 2000 finding. Several commenters claim that EPA only identified health concerns for Hg (and potentially Ni) but not other HAP from coal-fired EGUs in the 2000 finding, and, thus, cannot regulate HAP other than Hg because the 2000 finding authorizes only the regulation of Hg. One commenter questioned the Hg emissions underlying the 2000 finding, specifically the fraction of total deposition attributable to U.S. EGUS and the fact that EPA projected an increase in U.S. EGU emissions from 1990 to 2010 though emissions actually declined.

Several commenters raised procedural issues related to the 2000 finding. Several commenters stated that the 2000 finding failed to provide public notice and comment. According to the commenters, the CAA requires that any decision made under CAA section 112(n) must go through public notice and comment. The commenters further stated that the failure to provide public notice and comment means that this MACT is outside EPA's statutory authority. One commenter stated that because the 2000 finding was never "fully ventilated" in front of the D.C. Circuit, the EPA's authority to regulate EGUs under CAA section 112(d) is directly at issue. The commenters claim that specific issues did not undergo

[64] 76 FR 24992.

[65] U.S. EPA 1998. Study of Hazardous Air Pollutant Emissions from Electric Utility Steam Generating Units—Final Report to Congress. EPA–453/R–98–004a. February.

[66] U.S. EPA, 1997.

[67] "Where a statute is precautionary in nature, the evidence difficult to come by, uncertain, or conflicting because it is on the frontiers of scientific knowledge, the regulations designed to protect the public health, and the decision that of an expert administrator, [courts] will not demand rigorous step-by-step proof of cause and effect." *Ethyl Corp. v. EPA*, 541 F.2d 1, 28 (Ct. App. D.C. Circ. 1978).

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public notice and comment, including least-cost regulatory options, the impact of regulation on electricity reliability, and EPA's interpretation of the requirements under CAA section 112(n)(1)(A). One commenter claims that EPA attempted to provide after-the-fact support for its 2000 finding with new legal analysis and new factual information, contrary to *New Jersey* v. *EPA* that held that EPA may not revisit its 2000 finding except through delisting under CAA section 112(c)(9). One commenter stated that EPA's 2000 finding should be reviewed when EPA issues the actual NESHAP.[68] One commenter stated that the 2000 finding ignored EO 12866.

Response: EPA agrees with the commenters that the 2000 finding was reasonable and disagrees with the commenters asserting that the 2000 finding was unreasonable or failed to follow proper procedural requirements.

The EPA agrees that reviewing courts defer to the reasoned scientific and technical decisions of an Agency charged with implementing complex statutory provisions such as those at issue in this case. As EPA stated in the preamble to the proposed rule, the EPA maintains that the 2000 finding was reasonable and based on well-supported evidence available at the time, including the Utility Study, the Mercury Study,[69] and the NAS study,[70] which all showed the hazards to public health and the environment from HAP emitted from EGUs. New technical analyses conducted by EPA confirm that it remains appropriate and necessary to regulate HAP emissions from EGUs. Furthermore, the EPA agrees with the commenters on several points raised, specifically that EGUs were and remain the largest anthropogenic source of several HAP in the U.S., that risk assessments supporting the 2000 finding indicated potential concern for several non-Hg HAP, and that several available control options would effectively reduce HAP emissions from U.S. EGUs.

The EPA agrees with the commenters that Congress did not exempt EGUs from section 112(d) HAP emission limits while simultaneously limiting emissions at other sources with less HAP emissions. Congress simply provided EPA with a separate path for listing EGUs by requiring that the Agency evaluate HAP emissions from EGUs and determine whether regulation under CAA section 112 was appropriate and necessary. Since 1990, the EPA has promulgated regulations requiring the use of available control technology and other practices to reduce HAP emissions for more than 170 source categories. U.S. EGUs are the most significant source of HAP in the country that remains unaddressed by Congress's air toxics program. The EPA listed EGUs in 2000 because the considerable amount of available data supported the conclusion that regulation of EGUs under CAA section 112 was appropriate and necessary. That finding was valid at the time, and EPA reasonably added EGUs to the CAA section 112(c) list of sources that must be regulated under CAA section 112.

The EPA acknowledges that we did not expressly define the terms appropriate and necessary in the 2000 finding, but the finding is instructive in that it shows that EPA considered whether HAP emissions from EGUs posed a hazard to public health and the environment and whether there were control strategies available to reduce HAP emissions from EGUs when determining whether it was appropriate to regulated EGUs.[71] When concluding it was necessary, the Agency stated that imposition of the requirements of the Act would not address the identified hazards to public health or environment from HAP emissions and that section 112 was the proper authority to address HAP emissions.[72] The EPA explained in the preamble to the proposed rule its conclusion that the 2000 finding was fully supported by the information available at the time,[73] and EPA stands by the conclusions in that notice. Furthermore, the EPA provided an interpretation of the terms appropriate and necessary that is wholly consistent with the 2000 finding. The EPA does not agree with the commenters that a quantification of emissions reductions or a specific identification of the available controls was necessary to support the 2000 finding and listing. The EPA considered the Utility Study when making the finding, and that study clearly articulated the various alternative control strategies that EGUs could employ to control HAP emissions.[74] As to emission reductions, the EPA cannot estimate the level of HAP emission reductions until the Agency proposes a CAA section 112(d) standard after a source category is listed.

The EPA disagrees with commenters that suggest it was not "rational" to determine that it was appropriate to regulate HAP emissions from EGUs due to the cancer risks identified in the Utility Study or the potential concerns associated with other HAP emissions from EGUs. Nothing in CAA section 112(n)(1)(A) suggests that EPA must determine that every HAP emitted by EGUs poses a hazard to public health or the environment before EPA can find it appropriate to regulate EGUs under CAA section 112. In fact, the EPA maintains that it must find it appropriate and necessary to regulate EGUs under CAA section 112 if it determines that any one HAP emitted from EGUs poses a hazard to public health or the environment that will not be addressed through imposition of the requirements of the Act. The EPA disputes the commenters' conclusion that the 2000 finding was limited to Hg and Ni emissions, but, even if it were, the EPA reasonably concluded that EGUs should be listed pursuant to CAA section 112(c) based on the Hg and Ni finding. As stated in the 2000 finding, cancer risks from some non-Hg metal HAP (including As, Cr, Ni, and Cd) were not low enough to be to eliminate as potential concern.[75] Source categories listed for regulation under CAA section 112(c) must be regulated under CAA section 112(d), and the D.C. Circuit has stated that EPA has a "clear statutory obligation to set emission standards for each listed HAP". *See Sierra Club* v. *EPA*, 479 F.3d 875, 883 (D.C. Cir. 2007), *quoting National Lime Association* v. *EPA*, 233 F.3d 625, 634 (D.C. Cir. 2000). Therefore, even if EPA concluded that CAA section 112(n)(1) authorized a different approach for regulating HAP emissions from EGUs, the chosen course which is supported by the CAA (*i.e.*, listing under CAA section 112(c)) requires the Agency to regulate under CAA section 112(d) consistent with the statute and case law interpreting that provision.

The EPA disagrees that there is any concern regarding the validity of the 2000 finding or that the emissions information provided in the 2000 finding makes the finding "questionable" as stated by some of the commenters. The EPA maintains that the 2000 finding was sound and fully supported by the record available at the time, including the future year emissions projections. Therefore, the listing of EGUs is valid based on that finding alone. Even though Hg emissions have decreased since the 2000 finding instead of increasing as projected, the new technical analyses confirm that Hg emissions from EGUs continue to pose hazards to public

[68] *See UARG* v. *EPA*, 2001 WL 936363, No. 01–1074 (D.C. Cir. July 26, 2001).

[69] U.S. EPA, 1997.

[70] NAS, 2000.

[71] 65 FR 79830.

[72] *Id.*

[73] 65 FR 24994–24996.

[74] *See* Chapter 13 of the Utility Study (U.S. EPA, 1998).

[75] 76 FR 79827.

health and the environment. The EPA also indicated potential concern for several non-Hg HAP in the 2000 finding. It is well established that even small amounts of HAP can cause significant harm to human health and the environment.

The EPA agrees with the commenters who assert that the 2005 action was in error and disagrees with the commenters that the 2005 action invalidated the 2000 finding. As fully described in the preamble to the proposal, the EPA erred in the 2005 action by concluding that the 2000 finding lacked foundation. The 2005 action improperly conflated the "appropriate" and "necessary" analyses by addressing the "after imposition of the requirements of the Act" in the appropriate finding as well as the necessary finding. The EPA also indicated that it was not reasonable to interpret the necessary prong of the finding as a requirement to scour the CAA for alternative authorities to regulate HAP emissions from stationary sources, including EGUs, when Congress provided section 112 for that purpose. The EPA asserts that the 2000 finding was sound and fully supported by the record available at the time for all the reasons stated in this final rule and the proposed rule. The 2005 action interpreted the statute in a manner inconsistent with the 2000 finding and attempted to delist EGUs without complying with the mandates of CAA section 112(c)(9)(B). *See New Jersey*, 517 F.3d at 583 (vacating the 2005 "delisting" action). In the preamble to the proposed rule, the EPA set forth a revised interpretation of CAA section 112(n)(1) that is consistent with the statute and the 2000 finding. The EPA also explained in the preamble to the proposed rule why the 2005 action was not technically or scientifically sound. The EPA specifically addressed the errors associated with the 2005 action in the preamble to the proposed rule, and commenters' assertions do not cause us to revisit these issues. The commenter is also incorrect in suggesting that a change in interpretation is per se invalid and provided no support for that position. *See National Cable & Telecommunications Ass'n, et al.*, v. *Brand X Internet Services, et al.*, 545 U.S. 967, 981 (discussing the deference provided to an Agency changing interpretations, the Court stated "change is not invalidating, since the whole point of *Chevron* deference is to leave the discretion provided by ambiguities of a statute with the implementing Agency.") (Internal citations and quotations omitted).

The EPA disagrees with the commenters who raise concerns about the validity of the 2000 finding because the data on which that finding was based were more than 10 years old. The EPA made the finding at that time based on the scientific and technical information available, and the finding is wholly supported by that information. In addition, even though not required to do so, the EPA has since conducted new technical analyses utilizing the best information available in 2010 as several years have passed since the 2000 finding. These new analyses confirm that HAP emissions from EGUs continue to pose a hazard to public health and the environment, even after taking into account emission reductions that have occurred since 2000 from promulgated rules, settlements, and consent decrees. *See* 76 FR 24991.

Contrary to the commenter's assertion, the EPA did not violate CAA section 307(d) by not providing a notice and comment opportunity before making the December 2000 appropriate and necessary finding. One commenter challenged EPA's 2000 finding and listing on the same grounds, and the D.C. Circuit dismissed the case because CAA section 112(e)(4) clearly states that listing decisions cannot be challenged until the Agency issues final emission standards for the listed source category. *See UARG* v. *EPA*, 2001 WL 936363, No. 01–1074 (D.C. Cir. July 26, 2001). The EPA has provided the public an opportunity to comment on both the 2000 finding and the 2011 analyses that support the appropriate and necessary determination as part of the proposed rule, and anyone may challenge the listing in the D.C. Circuit in conjunction with a challenge to this final rule. The commenters could have also commented on the CAA section 112(n)(1) (*e.g.*, the Utility Study and the Mercury Study) studies in 2000 as they were included in the docket, but EPA is not aware of any comments on those studies. In any case, these studies were peer reviewed and considered the best information available at that time. The EPA has fully complied with the rulemaking requirements of CAA section 307(d).

The EPA also disagrees with the commenters' characterization of the *New Jersey* case. The D.C. Circuit did not say, as one commenter suggested, that EPA is not able to consider additional information that is collected after the 2000 finding; instead, the Court stated that EPA could not revise its appropriate and necessary finding and remove EGUs from the CAA section 112(c) list without complying with the delisting provisions of CAA section 112(c)(9). *See New Jersey*, 517 F.3d at 582–83. The EPA also disagrees with the commenter's assertion that EPA disregarded EO 12866 when making the 2000 finding. As stated in the Federal Register notice, the 2000 finding did not impose regulatory requirements or costs and was reviewed by the Office of Management and Budget (OMB) in accordance with the EO.[76]

2. New Technical Analyses

a. General Comments on New Technical Analyses

Comment: Several commenters stated that the new analyses, including the risk assessments and technology assessments, confirm that it remains appropriate and necessary to regulate U.S. EGU HAP under CAA section 112. These commenters stated that the new analyses provide even more support than the risk and technology information available at the time the 2000 finding was made, including information on further developed emissions control technology, proven and cost-effective control of acid gases using trona and dry sorbent injection, stabilized natural gas prices that makes fuel switching and switching dispatch to underutilized combined cycle plants more feasible, more information on ecosystem impacts from HAP, "hotspots" from the deposition of Hg around EGUs, the potential for re-emission of Hg, updated emissions data and future projections of HAP emissions, and modern air pollution modeling tools. One commenter states affordable control technology has been in use in this sector for 10 to 40 years, and studies on EGU-attributable Hg hazard has undergone two in-depth EPA reviews, as well as a review by the NAS. Several commenters claimed that regulating U.S. EGUs is appropriate and necessary to protect public health based on information provided in the new technical analyses. These commenters acknowledged the substantial reductions in HAP from recent regulations and new studies that confirm serious health risks from HAP exposure. One commenter stated that new studies show higher risks to fetuses than previously estimated, increasing the potential for neurodevelopmental effects in newborns. One commenter noted that EGUs are a major source of HAP, including HCl, HF, As, antimony, Cr, Ni, and selenium, all of which adversely affect human health. The commenter stated that because of these health effects, the EPA has ample evidence to support a determination

[76] 65 FR 79831.

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that non-Hg HAP emissions present a risk to human health.

Other commenters disagreed that the new analyses confirm that it remains appropriate and necessary to regulate U.S. EGUs. One commenter claims that EPA tried to use the new technical analyses to provide retroactive justification for the 2000 finding, which only found "plausible links" of health effects and "potential concerns" of health effects of certain metal emissions, dioxins and acid based aerosols. The commenter also asserted that none of these new analyses demonstrate that EGU regulation under section 112 is necessary and appropriate.

One commenter agreed that EPA may supplement its finding with new information, analyses and arguments to reaffirm the 2000 finding up until EPA issues final emissions standards. The commenter noted that the CAA does not freeze the finding. However, another commenter argued that EPA does not have the authority to rely on new technical analyses because the CAA requires EPA to make the finding on the basis of the Utility Study alone. According to that commenter, the EPA unreasonably stretched the language of CAA section 112 by considering new technical analyses.

Citing a report from Dr. Willie Soon that was submitted to the SAB, one commenter stated that the new technical analyses supporting the proposed rule do not conform to the Information Quality Act, which requires that information relied on by EPA be accurate, reliable, unbiased, and presented in a complete and unbiased manner.

Response: The EPA agrees with the commenters that state that the new technical analyses (*e.g.*, the risk assessments and technology assessment) confirm the 2000 finding and disagrees with the commenters that state otherwise. The EPA also agrees with the commenters that the 2000 finding was valid at the time it was made based on the CAA section 112(n)(1) studies and other information available to the Agency at that time. Furthermore, the EPA agrees with commenters that the final rule will lead to substantial reductions in HAP emissions from EGUs, that control of the HAP is estimated to lead to public health and environmental benefits as discussed in the RIA, that Hg emissions from U.S. EGUs pose a hazard to public health, and that non-Hg HAP emissions from EGUs pose a hazard to public health.

Although these new analyses were not required, the EPA agrees with the commenters that stated that EPA is authorized to conduct additional analyses to confirm the 2000 finding. The EPA disagrees with the commenter's assertion that the Agency is not authorized to consider new information and at the same time unable to use the information available in 2000 because, according to the commenter, that information is "stale." Under this theory, the Agency could not ever make an appropriate and necessary finding prospectively, thereby excusing the Agency from its obligations to protect public health and the environment because it did not diligently act in undertaking its statutory responsibility to establish CAA section 112(d) standards within two years of listing EGUs. *See* CAA section 112(c)(5). This is an illogical result that finds no basis in the statute. The EPA also disagrees with the commenter's assertion that EPA may not consider new analyses conducted after the Utility Study in determining whether it is appropriate and necessary to regulate EGUs under section 112 for the reasons set forth in the preamble to the proposed rule.[77]

The EPA disagrees with the commenter's implication that EPA conducted the new analyses because of alleged flaws in the 2000 finding. As explained in detail in the preamble to the proposed rule, the 2000 finding was wholly valid and reasonable based on the information available to the Agency at that time, including the Utility Study. Further, the EPA maintains that had it complied with the statutory mandate to issue CAA section 112(d) standards within two years of listing EGUs, the EPA would likely have declined to conduct new analyses. The EPA conducted new analyses because over 10 years had passed since the 2000 finding, and EPA wanted to evaluate HAP emissions from U.S. EGUs based on the most accurate information available, though the Agency was not required to reevaluate the 2000 finding. In conducting the new analyses, the EPA used this updated information to further support the finding.

The EPA strongly disagrees with the commenter that stated that EPA failed to conform to the Information Quality Act. The EPA used peer reviewed information and quality-assured data in all aspects of the technical analyses used to support the appropriate and necessary finding supporting this regulation. In addition, the EPA submitted the Hg Risk TSD to the SAB for peer review, which "supports the overall design of and approach to the risk assessment and finds that it should provide an objective, reasonable, and credible determination of the potential for a public health hazard from mercury emitted from U.S. EGUs."[78] The SAB received the comments from Dr. Willie Soon, and had those comments available for consideration in their deliberations regarding the Hg risk analysis. The SAB specifically supported elements of the analysis criticized by Dr. Willie Soon regarding the use of the EPA RfD as a benchmark for risk and the connection between Hg emissions from U.S. EGUs and MeHg concentrations in fish. In addition, the risk assessment methodology for the non-Hg case studies is consistent with the methodology that EPA uses for assessments performed for Risk and Technology Review rulemakings, which underwent peer review by the SAB in 2009.[79] During the public comment period, the EPA also completed a letter peer review of the methods used to develop inhalation cancer risk estimates for Cr and Ni compounds, and those reviews were generally supportive. See above description of this peer review. For the final rulemaking, the EPA revised both risk assessments consistent with recommendations from the peer reviewers. The EPA relies on the SAB's review of the quality of the information supporting the analytical results. Accordingly, contrary to the commenters' assertions, the EPA acted consistently with the Information Quality Act as well as EPA's and OMB's peer review requirements.

b. Hg Emissions Estimates

1. Hg Emissions From EGUs

Comment: The commenters addressed the 2005 and 2016 emissions estimates for Hg and expressed concern that inaccuracies in these emissions estimates result in overestimates of risks from Hg deposition. Further, commenters compared EPA's 2010 estimate and 2016 estimate, and stated that it is not possible for 29 tons to be a correct inventory total for Hg emissions in both years given expected reductions from CSAPR. In addition, commenters specifically commented on assumptions included in the Integrated Planning Modeling (IPM), including a concern that Hg speciation factors used by IPM overestimate emissions in 2016. Other commenters noted that EGU sources are the predominant source of U.S. anthropogenic Hg emissions, particularly the oxidized and particulate forms of Hg that are of primary concern for Hg deposition.

Response: The EPA disagrees with commenters' assertions that the EPA's

[77] 76 FR 24988.

[78] U.S. EPA–SAB, 2011.

[79] U.S. EPA–SAB, 2010.

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emissions estimates overestimate risk. While EPA agrees that the 2005 Hg emissions may be overestimated, such an overestimate in 2005 would actually lead to an underestimate of risk in 2016 and not an overestimate of risk, as claimed by the commenter, because the ratio approach used by EPA to scale fish tissue data would underestimate risk if 2005 Hg estimates were overestimated. Since the 2005 emissions are not used as a starting point for 2016 emissions from IPM, any 2005 overestimate does not affect the 2016 emissions levels. The 2016 emissions are computed by IPM based on forecasts of demand, fuel type, Hg content of the fuel, and the emissions reductions resulting from each unit's configurations. *See* IPM Documentation for further information, which is available in the docket. No commenter has provided any evidence that the IPM 2016 emissions projection methodology resulted in an overestimate.

The EPA acknowledges that the current Hg emissions estimate would not be the same as the 2016 Hg emissions estimate given that compliance with CSAPR is anticipated to have some Hg co-benefits. For this reason, the EPA reflected emission reductions anticipated from CSAPR in the Hg deposition modeling for 2016 in the Hg Risk TSD. In the final rule, the EPA revised the estimate of Hg emissions remaining from U.S. EGUs in 2016, which includes additional emission reductions anticipated from the final CSAPR. The revised estimate shows that U.S. EGUs would emit 27 tons of Hg in 2016. Although EPA does not use the current Hg emissions estimates in any of the risk calculations, the EPA estimates that current Hg emissions are 29 tons. Conclusions about the trend between current emissions and emissions in 2016 are limited by the fact that different methods were used to compute the two estimates, as fully explained in the revised Emissions Overview memo in the docket.

The EPA disagrees with the commenter's assertion that incorrect Hg emission factors result in incorrect 2016 emissions. The 2016 projected Hg emissions are not based on emissions factors. The 2016 Hg emissions are computed by the IPM based on forecasts of demand, fuel type, Hg content of the fuel, and the emissions reductions resulting from each unit's configurations. The speciation factors referenced by the commenter provide a basis for the speciation of total projected Hg emissions into particulate, divalent gaseous, and elemental species, and do not impact the total amount of Hg emissions.

The EPA agrees with commenters who noted that EGU sources are the predominant source of U.S. anthropogenic Hg emissions, and in particular the oxidized and particulate forms of Hg that are of primary concern for Hg deposition.

2. Global Hg Emissions

Comment: Several commenters stated that predicted Hg deposition relies heavily on the amount of gaseous elemental Hg used to define the boundary and initial conditions of a model, e.g., the Hg that enters the U.S. from outside the U.S. boundaries. The commenters asserted that this is especially important because Hg emissions from Asia—the region immediately upwind of North America that affects U.S. Hg deposition significantly and also affects it the most compared to other regions—are expected to continue to increase.[80] [81] [82] [83] [84] [85] According to the commenter, this would affect the amount of Hg in the boundary and initial conditions. The commenters claim that EPA's modeling did not account for these emission changes, thus leading to an overestimate of U.S. EGU-attributable deposition in 2016.

Several commenters noted that Hg emissions from U.S. EGUs are small when compared to global Hg emissions totals and natural sources within the U.S. These commenters used a variety of information to support alternative conclusions about the necessity to control U.S. EGU emissions to reduce Hg risk: global Hg emissions inventories, global and regional photochemical modeling research, and observation-based assessments. A commenter stated that EPA has not acknowledged the dramatic decline in Hg emissions from U.S. EGUs since the late 1990s (approximately 50 percent) to the current level or consider the relative magnitude of Hg emissions from U.S. EGUs compared to other sources, natural (such as fires) and human-caused.

Response: The EPA disagrees that boundary and initial conditions used in modeling Hg deposition need adjustment for several reasons. First, the EPA does not use the first 10 days of the modeling simulation in the analysis, which is more than sufficient to remove the influence of initial conditions on Hg deposition estimates.[86] Second, it is difficult to accurately characterize the speciation of Hg that flows into the U.S. from other countries due to the lack of data near the boundaries of the modeling domain. Third, the boundary inflow for the CMAQ Hg modeling used in the Hg deposition modeling are based on a global model GEOS–CHEM simulation using a 2000 based global inventory.[87] A recently published comparison of global Hg emissions by continent for 2000 and 2006 found that total Hg emissions from Asia (and Oceania) total 1,306 Mg/yr in 2000 and 1,317 Mg/yr in 2006.[88] The EPA has determined that because the Asian Hg emissions estimated in this study are nearly constant between 2005 and 2006, any adjustments to the boundary conditions or adjustments to modeled Hg deposition would be invalid and inappropriate. Recent research has shown that ambient Hg concentrations have been decreasing in the northern hemisphere since 2000.[89] Because emissions from Asia have not appreciably changed between 2000 and 2006 and ambient Hg concentrations have been decreasing, ENVIRON's analysis contains incorrect assumptions and we need not address them further. For these reasons and the large uncertainties surrounding projected Hg

[80] Jaffe D., Prestbo E., Swartzendruber P., Weiss-Penzias P., Kato S., Takami A., Hatakeyama S., Kajii Y., 2005. "Export of Atmospheric Mercury From Asia," *Atmospheric Environment*, 39, 3029–3038.

[81] Jaffe D., Strode S., 2008. "Fate and Transport of Atmospheric Mercury From Asia," *Environmental Chemistry*, 5, 121.

[82] Pacyna E.G., Pacyna J.M., Sundseth K., Munthe J., Kindbom K., Wilson S., Steenhuisen F., Maxson P., 2010. "Global Emission of Mercury to the Atmosphere From Anthropogenic Sources in 2005 and Projections to 2020," *Atmospheric Environment*, 44, 2487–2499.

[83] Pirrone N., Cinnirella S., Feng X., Finkelman R.B., Friedli H.R., Leaner J., Mason R., Mukherjee A.B., Stracher G.B., Streets D. G., Telmer K., 2010. "Global Mercury Emissions to the Atmosphere From Anthropogenic and Natural Sources," *Atmospheric Chemistry and Physics*, 10, 5951–5964.

[84] Streets, D.G., Zhang, Q., Wu, Y., 2009. "Projections of Global Mercury Emissions in 2050." *Environmental Science & Technology* 43, 2983–2988.

[85] Weiss-Penzias P., Jaffe D., Swartzendruber P., Dennison J.B., Chand D., Hafner W., Prestbo E., 2006. "Observations of Asian Air Pollution in the Free Troposphere at Mt. Bachelor Observatory in the Spring of 2004," *Journal of Geophysical Research*, 110, D10304.

[86] Pongprueksa, P., Lin, C.J., Lindberg, SE., Jang, C., Braverman, T., Bullock, O.R., Ho, T.C., Chu, H.W., 2008. "Scientific Uncertainties in Atmospheric Mercury Models III: Boundary and Initial Conditions, Model Grid Resolution, and Hg (II) Reduction Mechanism." *Atmospheric Environment* 42, 1828–1845.

[87] Selin, NE., Jacob, D.J., Park, R.J., Yantosca, R.M., Strode, S., Jaegle, L., Jaffe, D. 2007. "Chemical Cycling and Deposition of Atmospheric Mercury: Global Constraints From Observations." *Journal of Geophysical Research-Atmospheres* 112.

[88] Streets *et al.*, 2009.

[89] Slemr, F., Brunke, E.G., Ebinghaus, R., Kuss, J., 2011. "Worldwide Trend of Atmospheric Mercury Since 1995." *Atmospheric Chemistry and Physics* 11, 4779–4787.

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global inventories, the EPA concludes that the most appropriate technical choice is to keep the Hg boundary conditions the same between the 2005 and 2016 simulations.

The EPA also disagrees with the commenters' assertion that EPA has not acknowledged the decline in Hg emissions for the U.S. EGUs since the late 1990s. The EPA analyzed historical, current, and future projected Hg emissions from the power generation sector, as cited in the preamble to the proposed rule. The EPA also disagrees with the commenters' assertions that EPA failed to consider the relative magnitude of Hg emissions from U.S. EGUs compared to other sources. As noted in the Hg Risk TSD, the EPA modeled Hg emissions from U.S. and non-U.S. anthropogenic and natural sources to estimate Hg deposition across the country. The EPA also determined the contribution of Hg emissions from U.S. EGUs to total Hg deposition in the U.S. by running modeling simulations for 2005 and 2016 with Hg emissions from U.S. EGUs set to zero. Based on the Hg Risk TSD, Hg emissions from U.S. EGUs pose a hazard to public health based on the total of 29 percent of modeled watersheds potentially at-risk. Our analyses show that of the 29 percent of watersheds with population at-risk, in 10 percent of those watersheds U.S. EGU deposition alone leads to potential exposures that exceed the MeHg RfD, and in 24 percent of those watersheds, total potential exposures to MeHg exceed the RfD and U.S. EGUs contribute at least 5 percent to Hg deposition.

The commenters suggest that Hg emissions from U.S. EGUs represent a limited portion of the total Hg emitted worldwide, including anthropogenic and natural sources. While EPA acknowledges that Hg emissions from U.S. EGUs are a small fraction of the total Hg emitted globally, it views the environmental significance of Hg emissions from U.S. EGUs and other domestic sources as a more germane consideration. Mercury is emitted from EGUs in three forms. Each form of Hg has specific physical and chemical properties that determine how far it travels in the atmosphere before depositing to the landscape. Although gaseous oxidized Hg and particle-bound Hg are generally local/regional Hg deposition concerns, all forms of Hg may deposit to local or regional watersheds. U.S. coal-fired power plants account for over half of the U.S. controllable emissions of the quickly depositing forms of Hg. Although emissions from international Hg sources contribute to Hg deposition in the U.S., the peer reviewed scientific literature shows that Hg emissions from U.S. EGUs in the U.S. significantly enhance Hg deposition and the response of ecosystems in the U.S. [90] [91] [92] [93]

c. Hg Deposition Modeling

1. General Comments on Deposition Modeling

Comment: Several commenters stated that according to the ENVIRON report, the EPA overestimated U.S. EGU-attributable Hg deposition by 10 percent on average (and up to 41 percent in some areas). The commenters claim this overestimation is the result of boundary condition treatment, the exclusion of U.S. fire emissions,[94] and Hg plume chemistry approach. In addition, one commenter referenced the same ENVIRON report and stated that before implementation of controls required by the proposed rule, areas with relatively high EGU-attributable Hg deposition (one-fifth or more of total deposition) in 2016 constitute less than 0.25 percent of the continental U.S. area, and only three grid cells have EGU contributions exceeding half of total deposition.

Another commenter suggested that current research shows that models of Hg atmospheric fate and transport overestimate the local and regional impacts of some anthropogenic sources, such as U.S. EGUs. Thus, according to the commenter, calculated contributions to Hg deposition and fish tissue MeHg levels from these sources represent upper bounds of actual contributions,[95] [96] and EPA should present results as estimates of lower and upper bound limits.

Response: The EPA disagrees with the information presented by ENVIRON. The ENVIRON report is based on the misapplication of multiple incommensurate modeling studies and false premises which include the incorrect notion that the boundary conditions are over-estimated and the idea that EPA should use in-plume chemistry that has not been explicitly characterized and peer reviewed. Reactions that may reduce gas phase oxidized Hg in plumes have not been explicitly identified in literature. Recent studies in central Wisconsin and central California suggest the opposite may happen; elemental Hg may be oxidized to Hg(II) in plumes.[97] [98] Better field study measurements and specific reaction mechanisms need to be identified before making conclusions about potential Hg in-plume chemistry or applying surrogate reactions in regulatory modeling. The possibility that Hg(0) is oxidized to Hg(II) in plumes suggests coal-fired power plant Hg contribution inside the U.S. may be underestimated in EPA modeling.

The EPA asserts that the numbers suggested by the commenter are inaccurate, as it is not appropriate to adjust EPA's deposition estimates based on previous Hg modeling done with older Hg chemistry, in-plume reactions that have not been explicitly identified, and erroneous adjustments to Hg boundary inflow. Recent research has shown that ambient Hg concentrations have been decreasing in the northern hemisphere since 2000.[99] The EPA declines to revise this analysis as commenter suggests for several reasons, including available evidence indicates that emissions from China have not appreciably changed between 2000 and 2006 [100] and ambient Hg concentrations have decreased, the commenter inappropriately comingled out–of-date Hg modeling simulations with EPA results, and ENVIRON's analysis has not undergone any scientific peer review and presents information with incorrect assumptions as noted in this response.

The EPA also disagrees with the commenter's interpretation of the applicability of wildfire Hg emissions to

[90] Caffrey *et al.*, 2010.

[91] Driscoll, C. T., Han, Y.-J., Chen, C. Y., Evers, D. C., Lambert, K. F., Holsen, T. M., *et al.*, (2007). "Mercury Contamination in Forest and Freshwater Ecosystems in the Northeastern United States." *BioScience*, 57(1).

[92] Keeler, G.J., Landis, M.S., Norris, G.A., Christianson, E.M., Dvonch, J.T., 2006. "Sources of Mercury Wet Deposition in Eastern Ohio, USA." *Environmental Science & Technology* 40, 5874–5881.

[93] White, E.M., Keeler, G.J., Landis, M.S., 2009. "Spatial Variability of Mercury Wet Deposition in Eastern Ohio: Summertime Meteorological Case Study Analysis of Local Source Influences." *Environmental Science & Technology* 43, 4946–4953.

[94] Finley, B.D., Swartzendruber, P.C., Jaffe, D.A., 2009. "Particulate Mercury Emissions in Regional Wildfire Plumes Observed at the Mount Bachelor Observatory." *Atmospheric Environment* 43, 6074–6083.

[95] Seigneur, C., Lohman, K., Vijayaraghavan, K., Shia, R.L., 2003. "Contributions of global and regional sources to mercury deposition in New York State." Environmental Pollution 123, 365–373.

[96] Seigneur, C., Vijayaraghavan, K., Lohman, K., Karamchandani, P., Scott, C., 2004. "Modeling the atmospheric fate and transport of mercury over North America: power plant emission scenarios." *Fuel Processing Technology* 85, 441–450.

[97] Kolker, A., Olson, M.L., Krabbenhoft, D.P., Tate, M.T., Engle, M.A., 2010. "Patterns of mercury dispersion from local and regional emission sources, rural Central Wisconsin, USA." *Atmospheric Chemistry and Physics* 10, 4467–4476.

[98] Rothenberg, SE., McKee, L., Gilbreath, A., Yee, D., Connor, M., Fu, X.W., 2010. "Wet deposition of mercury within the vicinity of a cement plant before and during cement plant maintenance." *Atmospheric Environment* 44, 1255–1262.

[99] Slemr *et al.*, 2011.

[100] Streets *et al.*, 2009.

[101] Finley *et al.*, 2009.

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this assessment. Finley *et al.*, (2009)[101] suggests caution when using their field data to make assumptions about Hg(p) emissions from wildfires; the estimated particulate Hg emissions from wildfires is based on one field site with a limited sample size, and the assumptions made (such as the observed Hg(p) to carbon monoxide ratios at this location) may not be valid on a broader scale.[102] Mercury emissions from wildfires are a re-volatilization of previously deposited Hg.[103] Given that electrical generating power plants are currently and historically have been among the largest Hg-emitting sources, the inclusion of wildfire emissions in a modeling assessment would necessarily increase the contribution from this emissions sector.

The EPA disagrees with the assertion that EPA failed to consider the relative magnitude of Hg emissions from U.S. EGUs compared to other sources and disagrees with the interpretation of EGU deposition presented in the ENVIRON report. As noted in the Hg Risk TSD, the EPA modeled Hg emissions from U.S. and non-U.S. anthropogenic and natural sources to estimate Hg deposition across the country. The EPA also determined the contribution of Hg emissions from U.S. EGUs to total Hg deposition in the U.S. by running modeling simulations for 2005 and 2016 with Hg emissions from U.S. EGUs set to zero. Hg emissions from U.S. EGUs pose a hazard to public health based on the total of 29 percent of modeled watersheds potentially at-risk. Our analyses show that of the 29 percent of watersheds with population at-risk, in 10 percent of those watersheds U.S. EGU deposition alone leads to potential exposures that exceed the MeHg RfD, and in 24 percent of those watersheds, total potential exposures to MeHg exceed the RfD and U.S. EGUs contribute at least 5 percent to Hg deposition. The ENVIRON report provides no risk analysis of EGU contribution.

The EPA disagrees that research [104] [105] presented by the commenter shows that U.S. EGU impacts are over-estimated. The commenter's references do not support this statement. The references provided by the commenter are based on Hg modeling that uses models that are no longer applied and that are based on out-dated Hg chemistry and deposition assumptions. Given the advances in Hg modeling since the early 2000s, the EPA does not believe an upper and lower bound estimate is necessary.

[100] Streets *et al.*, 2009.

[101] Finley *et al.*, 2009.

[102] *Id.*

2. Chemical Reactions

Comment: Several commenters stated that the CMAQ modeling fails to account for the chemical reduction of gaseous ionic Hg to elemental Hg that may occur in EGU plumes. The commenters noted that EPA did not use the Electric Power Research Institute's (EPRI) Advanced Plume-in-Grid Treatment, which includes a surrogate reaction to reduce gaseous ionic Hg to elemental Hg inside plumes. Multiple commenters claimed that the reduction of reactive gaseous Hg to gaseous elemental Hg has been reported in power plant plumes and that supporting data include atmospheric concentrations of speciated Hg measured downwind of power plant stacks at ground-level monitor sites and dispersion model predictions.[106] [107] A detailed description of various plume measurement studies is provided in EPRI Comments, Section 3.4: Plant Bowen, Georgia, Plant Pleasant, Wisconsin, and Plant Crist, Florida. One commenter believed the impact of grid resolution (12 km sized grid cells) on the CMAQ modeling was not appropriately addressed by EPA. Their concerns due to grid resolution include the notion that a source's emissions will be averaged over the entire grid cell. According to the commenter, such averaging causes an artificially fast dilution that smoothes out areas of high and low deposition, which may limit the ability of the model to simulate smaller areas of localized high deposition. This commenter believed that using the APT would address these issues.

Response: The EPA disagrees with the commenters' claims that oxidized Hg chemically reduces to elemental mercury within the plume. There is no evidence of these chemical reactions in the scientific literature. The references cited by the commenters are from non-peer reviewed reports and conference proceedings. The EPA does not consider information presented at conferences or industry reports to be peer reviewed literature, and consideration of oral presentation material would be inappropriate. Further, even these cited references do not provide sufficient information for incorporating the supposed reactions into the modeling (*e.g.*, specific chemical reactions, reaction rates, etc.); rather, the cited references only suggest that oxidized gas phase Hg could be reduced and postulate a possible pathway.

Recent studies in central Wisconsin and central California suggest the opposite may happen; elemental Hg may be oxidized to Hg(II) in plumes.[108] [109] Better field study measurements and specific reaction mechanisms need to be identified before making conclusions about potential Hg in-plume chemistry or applying surrogate reactions in regulatory modeling. Currently, models such as Advanced Plume Treatment (APT) use a surrogate reaction for the potential reactive gas phase Hg reduction that may or may not occur in plumes.[110] Reactions that may reduce gas phase oxidized Hg in plumes have not been explicitly identified in literature. The application of potentially erroneous in-plume chemistry that is a fundamental component of APT would be inappropriate. In addition, the APT is not available in the most recent version of CMAQ. It would be inappropriate for EPA to apply an out of date photochemical model with in-plume chemistry that has not been shown to exist.

The EPA agrees with the commenter that the CMAQ modeling with 12 km grid resolution may provide a lower bound estimate on EGU contribution as higher impacts using finer grid resolution are possible. The commenter's assertion that EGU impacts are likely higher further supports the final conclusions of the exposure modeling assessment. The EPA notes that the application of a photochemical model at a 12 km grid resolution for the entire continental U.S. is more robust in terms of grid resolution and scale that anything published in literature and represents the most advanced modeling platform used for a national Hg deposition assessment.

3. Modeled Deposition Compared to Measured Deposition

Comment: Multiple commenters expressed dissatisfaction related to EPA's model performance evaluation of CMAQ estimated Hg deposition. The commenters stated that EPA failed to evaluate the CMAQ model against real-world measurements and that EPA fails to provide first-hand information on wet and dry deposition processes. The commenters also stated that EPA needs

[103] Wiedinmyer, C., Friedli, H., 2007. "Mercury emission estimates from fires: An initial inventory for the United States." *Environmental Science & Technology* 41, 8092–8098.

[104] Seigneur *et al.*, 2003.

[105] Seigneur *et al.*, 2004.

[108] Kolker *et al.*, 2010.

[109] Rothenberg *et al.*, 2010.

[110] Vijayaraghavan, K., Seigneur, C., Karamchandani, P., Chen, S.Y., 2007. "Development and application of a multipollutant model for atmospheric mercury deposition." *Journal of Applied Meteorology and Climatology* 46, 1341–1353.

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to assess how predicted values of deposition compare to Mercury Deposition Network (MDN) data and how predicted values of ambient speciated Hg concentrations compare to measurement networks like AMNet and SEARCH. In addition, commenters stated that EPA used highly aggregated performance metrics comparing model estimates to observations that they believe result in a degraded and lenient operational evaluation of the modeling system. A commenter suggested that EPA's model performance provides no confidence for the intended purpose of estimating deposition near point sources. One commenter simply noted that EPA's model over-estimated total Hg wet deposition at MDN monitors. Finally, several commenters noted that EPA presented a negative modeled wet deposition total in the Air Quality Modeling TSD, which is physically impossible.

Response: EPA agrees with the commenters that the negative estimate for wet deposition in the Air Quality Modeling TSD was an error. This error reflected an incorrect calculation in the post-processing of model and observation pairs that only influenced the calculation of model performance metrics. The error has been fixed, and the model performance metrics in the revised Air Quality Modeling TSD have been updated. This error did not affect Hg deposition. In response to comments, the EPA provided additional model performance evaluation by season to the revised Air Quality Modeling TSD. In addition, in response to comments, the EPA also included model performance evaluation for total Hg wet deposition for the 36 km modeling domain in the revised Air Quality Modeling TSD.

The EPA disagrees that it did not conduct an assessment comparing CMAQ total Hg wet deposition estimates to MDN data. The Air Quality Modeling TSD clearly shows a comparison of CMAQ estimated total Hg wet deposition with MDN data for the entire length of the modeling period. The CMAQ wet deposition of Hg has been and will continue to be extensively evaluated against MDN sites.[111] There is no dry deposition monitoring network, which precludes evaluating CMAQ dry deposition processes. The EPA disagrees that an evaluation of ambient speciated Hg against routine monitor networks such as AMNet or SEARCH would be useful for this particular modeling application. The AMNet Hg network did not exist in 2005, which is EPA's baseline model simulation time period, and the SEARCH network started making preliminary measurements of Hg at one or two sites in 2005. In addition, measurement artifacts related to gaseous oxidized Hg are difficult to quantify and make direct comparison to model estimates problematic.[112] Considering the problems associated with TEKRAN measurements of ambient Hg and the sparse nature of routine measurements in the U.S., the EPA did not compare ambient Hg against model estimates.

The EPA disagrees that the model performance presented in the air quality TSD is insufficient. The EPA asserts that the model performance evaluation is generally similar to the level of model performance presented in literature. One commenter presented the results of several Hg modeling studies as providing information that the commenter believes to be relevant for this assessment in terms of model performance metric estimation and the level of model performance evaluation shown for assessments modeling Hg near point sources. For example, one cited study titled "Modeling Mercury in Power Plant Plumes" models near-source Hg chemistry from U.S. EGUs, but provides absolutely no information about model performance evaluation.[113]

Another commenter identified two studies as supposedly having Hg modeling results that are applicable to EPA's analysis.[114] [115] These studies present similar model performance metrics as EPA. The EPA disagrees that the Agency used "highly aggregated performance metrics" that result in degraded and lenient model evaluation. The studies presented [116] [117] as relevant for point source mercury modeling use an approach to aggregate the operational performance metrics across many monitor locations as did EPA; however, these articles calculate long term annual averages of modeled and observed total Hg wet deposition before estimating performance metrics. It is common practice to pair modeled estimates and observations in space and time (weekly in this case) and estimate performance metrics, then average all the metrics together. The latter is the approach taken by the EPA and should have been taken by the studies presented by the commenter. The EPA used a more stringent approach to match observations and predictions and aggregation of operational model performance. The EPA agrees that the commenter accurately restated total wet deposition model performance information provided by the EPA in the Air Quality Modeling TSD. To provide context, other Hg modeling studies show a positive bias for annual total Hg wet deposition.[118] [119] An annual Hg modeling application done by ENVIRON [120] and the Atmospheric and Environmental Research for Lake Michigan Air Directors Consortium show seasonal average normalized bias between 70 and 158 percent and seasonal average normalized error between 72 and 503 percent.[121] These results indicate a very large over-estimation tendency. The model performance shown by EPA is consistent with other long-term Hg modeling applications.

4. Excess Local Deposition From Hg Emissions From U.S. EGUs (Deposition Hotspots)

Comment: One commenter stated that reducing Hg will benefit local environments. The commenter stated that a 2007 study confirmed the presence of Hg "hotspots" downwind from coal-fired power plants and confirmed that coal-fired power plants within the U.S. are the primary source of Hg to the Great Lakes and the Chesapeake Bay.[122] The commenter also stated that the study is consistent with a major Hg deposition study conducted

[111] Bullock, O.R., Atkinson, D., Braverman, T., Civerolo, K., Dastoor, A., Davignon, D., Ku, J.Y., Lohman, K., Myers, T.C., Park, R.J., Seigneur, C., Selin, NE., Sistla, G., Vijayaraghavan, K., 2009. "An analysis of simulated wet deposition of mercury from the North American Mercury Model Intercomparison Study." *Journal of Geophysical Research-Atmospheres* 114.

[112] Lyman, S.N., Jaffe, D.A., Gustin, M.S., 2010. "Release of mercury halides from KCl denuders in the presence of ozone." *Atmospheric Chemistry and Physics* 10, 8197–8204.

[113] Lohman *et al.*, 2006.

[114] Seigneur, C., Lohman, K., Vijayaraghavan, K., Jansen, J., Levin, L., 2006. "Modeling atmospheric mercury deposition in the vicinity of power plants." *Journal of the Air & Waste Management Association* 56, 743–751.

[115] Vijayaraghavan, K., Karamchandani, P., Seigneur, C., Balmori, R., Chen, S.–Y., 2008. "Plume-in-grid modeling of atmospheric mercury." *Journal of Geophysical Research-Atmospheres* 113.

[116] Seigneur, C., Lohman, K., Vijayaraghavan, K., Jansen, J., Levin, L., 2006. "Modeling atmospheric mercury deposition in the vicinity of power plants." *Journal of the Air & Waste Management Association* 56, 743–751.

[117] Vijayaraghavan, K., Karamchandani, P., Seigneur, C., Balmori, R., Chen, S.-Y., 2008. "Plume-in-grid modeling of atmospheric mercury." *Journal of Geophysical Research-Atmospheres* 113.

[118] *Id.*

[119] Vijayaraghavan *et al.*, 2007.

[120] Yarwood, G, Lau, S., Jia, Y., Karamchandani, P., Vijayaraghavan, K. 2003. Final *Report: Modeling Atmospheric Mercury Chemistry and Deposition with CAMx for a 2002 Annual Simulation.* Prepared for Wisconsin Department of Natural Resources. *http://www.gypsymoth.wi.gov/air/toxics/mercury/hg_X97579601_appB.pdf.*

[121] Yarwood *et al.*, 2003.

[122] Evers, David C. *et al.*, 2007. "Biological Mercury Hotspots in the Northeastern United States and Southeastern Canada," *Bioscience.* Vol. 57 No. 1. p. 29.

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by the EPA and the University of Michigan that concluded that approximately 70 percent of Hg wet deposition resulted from local fossil fuel emissions in the region.[123]

One commenter agreed with the Agency's assessment of the potential for deposition "hotspots" that shows that Hg deposition near EGUs can be three times as large as the regional average. The commenter stated that this excess Hg deposition would substantially increase the health and environmental risks associated with emissions at these sites. The same commenter also stated that EPA applied a conservative methodology to quantify near-source Hg deposition. The commenter stated that maximum excess local Hg deposition may be significantly underestimated by averaging high deposition sites downwind of an EGU in the direction of prevailing winds with lower excess deposition at locations close to but frequently upwind of the facility. The same commenter suggests that had EPA used CMAQ and individual 12x12 km^2 grid cells to quantify local deposition, the model could increase the excess Hg deposition at these locations significantly and place them at even greater risk of adverse health and environmental effects of HAP from U.S. EGUs.

One commenter stated that the Hubbard Brook Research Foundation issued a report in 2007 that identified five Hg hotspots, one of which was in the Adirondack Park, along with four suspected hotspots.[124] The commenter stated that this study also provides a good description of the impacts of Hg on the Common Loon, which is a symbol of a healthy Adirondack environment.

One commenter stated that there is there is no evidence of Hg hotspots due to local deposition associated with coal-fired power plants. According to the commenter, the EPA's use of a 50 km radius to calculate hotspots is flawed. The commenter stated that modeling studies show that deposition of Hg emitted from power plants is not confined to a 50-km radius around the plants and that most emissions from power plants travel beyond 50 km.[125]

Several commenters stated that the EPA does not adequately define hotspots in this proposed rule. Those same commenters cited a previous EPA definition of hotspots as "a waterbody that is a source of consumable fish with MeHg tissue concentrations, attributable solely to utilities, greater than EPA's MeHg water quality criterion of 0.3 mg/kg" (milligrams per kilogram).[126] The same commenters stated that it is unclear why EPA changed from defining a hotspot by fish tissue MeHg concentration to defining a hotspot by depositional excess. Two commenters suggested that a Hg hotspot is a specific location that is characterized by elevated concentrations of Hg exceeding a well-established criterion, such as a reference concentration (RfC) when compared to its surroundings. Those same commenters stated that identifying Hg hotspots should not be constrained to locations where concentrations can be attributed to a single source or sector.[127] One of those two commenters noted that others have defined "hotspots as a spatially large region in which environmental concentrations far exceed expected values, with such values (i.e. concentrations) being 2 to three standard deviations above the relevant mean."[128]

One commenter stated that Hg concentrations are not always highest at sites closest to a major source. The commenter referred to a study[129] that demonstrated that concentrations of atmospheric reactive gaseous Hg, gaseous elemental Hg, and fine particulate Hg were lower when measured 25 km from a 1,114 MW coal-fired EGU than when measured 100 km away. The commenter stated that these findings contradict the idea, implicit in EPA's hotspot analysis, that reactive gaseous Hg decreases with distance from a large point source.

One commenter provided information from a non-peer reviewed report with wet Hg deposition measurements downwind from the coal-fired power plant Crist in Pensacola, FL. The commenter stated that using the same data from these same wet deposition sites, one study[130] found that Hg wet deposition and concentrations did not differ in a statistically significant manner among these three sites and that the concentrations values were similar to those from Mercury Deposition Network (MDN) sites that are more than 50 km away from Plant Crist located along the Northern Gulf of Mexico coast.

Another commenter stated that Plant Crist installed a wet scrubber and has operated that scrubber continuously since December 2009. The commenter stated that the scrubber reduces total Hg emissions by about 70 percent and reduces emissions of reactive gaseous Hg by about 85 percent. The commenter cited a non-peer reviewed conference presentation[131] that reported changes in Hg wet deposition relative to historic measurements. The commenter stated that, taken collectively, these findings show that increased local total Hg deposition, possibly due to EGUs, and deposition changes due to changes in EGU emissions, are small.

Two commenters stated that a study by the Department of Energy (DOE) that collected and analyzed soil and vegetation samples for Hg near three U.S. coal-fired power plants—one in North Dakota, one in Illinois, and one in Texas—found no strong evidence of "hotspots" around these three plants.

Two commenters stated that analysis of long-term trends in Hg emissions from coal-fired EGUs and wet deposition in Florida concluded that statistical analysis does not show evidence of a significant relationship between temporal trends in Hg emissions from coal-fired EGUs in Florida and Hg concentrations in precipitation during 1998 to 2010.

Two commenters stated that the Hg Risk TSD presents no information, summary statistics, and/or actual calculations showing how excess deposition within 50 km of an EGU source is obtained. The commenters stated that by assessing only Hg deposition attributable to EGUs, the EPA fails to provide a context for all other sources of Hg deposition. The commenters stated that the Agency does not explain why deposition from the top 10 percent of EGU Hg emitters does not decline, despite substantial reductions in modeled Hg emissions from those sources between 2005 and 2016.

[123] Cohen, *et al.*, 2004. "Modeling the Atmospheric Transport and Deposition of Mercury to the Great Lakes," *Environmental Research 95*, (247–265).

[124] Driscoll, C.T., D. Evers, K.F. Lambert, N. Kamman, T. Holsen, Y-J. Han, C. Chen, W. Goodale, T. Butler, T. Clair, and R. Munson. Mercury Matters: Linking Mercury Science with Public Policy inthe Northeastern United States. 2007. Hubbard Brook Research Foundation. Science Links Publication. Vol. 1, no. 3.

[125] Seigneur *et al.*, 2006.

[126] U.S. EPA, 2005. 40 CFR Part 63 [OAR–2002–0056; FRL–7887–7] RIN 2060–AM96. *Revision of December 2000 Regulatory Finding on the Emissions of Hazardous Air Pollutants From Electric Utility Steam Generating Units and the Removal of Coal- and Oil-Fired Electric Utility Steam Generating Units From the Section 112(c).* Final rule, March 29.

[127] Evers *et al.*, 2007.

[128] Sullivan T., 2005. "The Impacts of Mercury Emissions from coal-fired Power Plants on Local Deposition and Human Health Risk." Presented at the Pennsylvania Mercury Rule Workgroup Meeting, October 28.

[129] Kolker, *et al.*, 2010.

[130] Caffrey, J.M., Landing, W.M., Nolek, S.D., Gosnell, K.J., Bagui, S.S., Bagui, S.C., 2010. "Atmospheric deposition of mercury and major ions to the Pensacola (Florida) watershed: spatial, seasonal, and inter-annual variability." *Atmospheric Chemistry and Physics* 10, 5425–5434.

[131] Krishnamurthy N., Landing W.M, Caffrey J.M., 2011. "Rainfall Deposition of Mercury and Other Trace Elements to the Northern Gulf of Mexico." Presented at the 10th International Conference on Mercury as a Global Pollutant, Halifax, Nova Scotia, Canada, July 27.

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According to the commenters this implies that the top 10 percent EGUs may have approximately as much of a regional effect as a local effect.

Two commenters stated that the CMAQ model has limitations when used to predict local deposition and tends to overestimate local deposition. The commenters stated that modeling studies using either a plume model or an Eulerian model predict that 91 to 96 percent of the Hg emitted by an EGU travels beyond 50 km.[132]

Response: The EPA agrees with the commenters that stated that Hg emissions from EGUs deposit locally and regionally and contribute to excess local deposition near U.S. EGUs. The EPA acknowledges additional studies [133] cited by those commenters that corroborate EPA's conclusions. However, the EPA disagrees with those commenters' characterization of the methodology used to calculate the potential for excess local deposition. In response, the EPA has clarified the methodology in the new TSD entitled "Technical Support Document: Potential for Excess Local Deposition of U.S. EGU Attributable Mercury in Areas near U.S. EGUs," which is available in the docket.

The EPA agrees that there is no generally agreed-upon definition of "hotspot." As discussed in the preamble and TSD, for the purposes of the appropriate and necessary finding, the EPA determined that information on the potential for excess deposition of Hg in areas surrounding power plants would be useful in informing the finding. The EPA disagrees with some commenters who misinterpreted the intent of the Hg deposition hotspot analysis. Specifically, the analysis is not of "Hg hotspots", which are often defined as high Hg concentration in fish, but rather of Hg deposition hotspots, defined as excess local Hg deposition around U.S. EGUs, as clarified in the new Local Deposition TSD. Because EPA did not identify "Hg hotspots" of high Hg concentrations in fish, the EPA's MeHg water quality criterion of 0.3 mg/kg is irrelevant to EPA's analysis of excess local Hg deposition for this rule.

The EPA disagrees that the analysis assumes that deposition of Hg is confined to a 50-km radius around power plants. The purpose of the EPA's analysis was to evaluate whether there existed "excess deposition of Hg in nearby locations within 50 km of EGUs that might result in Hg deposition 'hotspots'." As explained further in the new TSD, the EPA calculated the average EGU-attributable deposition (based on CMAQ modeling of Hg deposition) in the area 500 km around each plant and the average EGU-attributable deposition in the area 50 km around each plant. The difference between those two values is the excess local deposition around the plant. The EPA does not suggest Hg emissions from power plants stop at 50 km from the source. Some portion of EGU emissions deposit before 50 km, and some portion travels beyond 50 km. In addition, Hg disperses as it transports, so the average EGU contribution can be lower in areas beyond 50km relative to areas within 50km even though Hg emissions from EGUs are depositing into U.S. watersheds.

The EPA disagrees with some commenters' interpretation of the analysis as being focused on local deposition from all sources. In fact, the focus was on excess local deposition, rather than all local deposition. The EPA has clarified the purpose of the excess local deposition analysis in the new TSD. The EPA agrees that all EGUs add to local deposition, however, not all EGUs have local deposition that greatly exceeds regional deposition, which is the relevant question. The EPA disagrees that the DOE study referenced by the commenters attempted to assess the same analytical question as EPA's analysis. The DOE study focused on comparisons of total deposition near and far from power plants. The EPA's analysis did not focus on total Hg deposition, because as EPA acknowledges throughout its analysis, global sources of Hg deposition account for a large percentage of total Hg deposition. In addition, including global sources of Hg deposition would obscure the comparison of local and regional U.S. EGU-attributable Hg deposition. Because of regional deposition from both domestic and global sources of Hg, total Hg deposition at any location is unlikely to be highly correlated with local sources. The EPA's analysis focused on U.S. EGU-attributable Hg deposition and demonstrates that for some plants (especially those with high Hg emissions), there is local deposition of Hg that exceeds the average regional deposition around the plant.

The EPA's analysis shows heterogeneity in the amount of excess local deposition around plants. The new Local Deposition TSD shows that some plants can have local deposition that is less than the regional average deposition, suggesting that most of the Hg from those plants is transported regionally or that other EGUs in the vicinity of those plants dominate the deposition of Hg near the plants. This does not detract from the overall finding that around some power plants with high levels of Hg emissions excess local deposition is on average three times the regional EGU-attributable deposition around those plants.

The EPA disagrees that the Hg Risk TSD did not provide sufficient information regarding the excess local deposition calculation. Nonetheless, the EPA has further clarified the methodology in the new Local Deposition TSD, including further descriptions of the method used to calculate the local and regional deposition around power plants along with maps and tables of results.

The EPA disagrees with the commenters that stated that the discussion of local deposition in the Hg Risk TSD did not demonstrate that Hg deposition from the top 10 percent of EGU Hg emitters declines. Table 1 of the new Local Deposition TSD clearly shows that mean local deposition (within 50km of a plant) for the top 10 percent of emitters declines from 4.89 micrograms per cubic meter ($\mu g/m^3$) to 1.18 $\mu g/m^3$. What does not change is the percent local excess for EGU-attributable Hg deposition. This implies that while Hg deposition from EGUs is declining, there is still an excess contribution to local deposition relative to regional deposition; *e.g.*, because of dispersion, the contribution to average deposition outside 50 km from the plant is lower than the contribution to average deposition within 50 km of the plant.

The EPA disagrees that the information [134] provided by the commenter regarding the Crist plant and other coal-fired power plants in Florida is relevant to EPA's analysis of excess local deposition from U.S. EGUs because it is based on measurements of wet Hg deposition without consideration of dry Hg deposition, which can be a significant component of Hg deposition.

The EPA disagrees with the commenter regarding the interpretation of the literature related to the spatial extent of deposition of Hg emitted by U.S. EGUs. The EPA also disagrees that the peer-reviewed CMAQ model has limitations for this application or overestimates local deposition. The commenter does not provide any credible support for the assertion that grid-based models typically overestimate local deposition surrounding EGUs. The EPA maintains that the CMAQ photochemical model represents the best science currently available in simulating atmospheric

[132] Edgerton *et al.*, 2006.

[133] Driscoll *et al.*, 2007.

[134] EPRI, 2010.

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chemistry, transport, and deposition processes.

The study [135] cited by the commenter to support the notion that 91 to 96 percent of Hg emitted from power plants travels beyond 50 km is based on a photochemical transport model (the TEAM model) that does not employ current state-of-the-science and is not actively developed or updated. Furthermore, the modeling is based on grid cells that are 20 km in size, which limits generalizability to EPA modeling performed at 12 km grid resolution using a state of the science photochemical grid model. The cited modeling study ignores dry deposition of elemental Hg from all sources, an assumption that clearly limits the regional impacts from sources.[136] The methodology of this study cited by the commenter is critically flawed in that it presents no results where individual Hg emission sources are removed and the difference between the zero out simulation (where emissions from U.S. EGUs are set to zero) and the baseline model simulations are directly compared. Finally, the modeling study cited by the commenter presents an illustration of gridded total annual Hg deposition from the TEAM model for the eastern U.S. that clearly shows elevated annual total Hg deposition in the vicinity of coal-fired power plants in the Ohio River Valley and northeast Texas.

d. Hg Risk TSD

1. Assumption of Linear Proportionality in Relationship Between Changes in Hg Deposition and Changes in Fish Tissue Hg Concentrations (Mercury Maps)

Comment: Several commenters criticized EPA's assumption that changes in deposition resulting from U.S. EGU emissions of Hg will result in proportional changes in fish tissue Hg concentrations at the watershed level, as supported by the Mercury Maps modeling exercise. According to one commenter, the Mercury Maps model has limited capability to adequately determine bioaccumulation in fish. The same commenter stated that the Mercury Cycling Model (MCM) developed by EPRI is a more rigorous model that was developed expressly to evaluate the relationship between changes in atmospheric Hg deposition to waterbodies and changes in fish tissue MeHg levels.

Several commenters stated that the Mercury Maps model has many deficiencies. Those commenters stated that Mercury Maps is a static model unable to account for the dynamics of ecosystems that affect Hg bioaccumulation in fish, cannot consider non-air Hg inputs to watersheds, and assumes reductions in airborne Hg lead to proportional reductions in fish MeHg concentrations. Another commenter claimed that data that demonstrate a steady-state linear reduction in fish tissue MeHg in response to a reduction in atmospheric Hg deposition within watersheds do not exist and provided several references that they claimed show non-linear responses to changes in Hg deposition.[137] [138]

The same commenter disagreed with EPA's interpretation of Figure 2–17 in the March TSD and stated that a U.S. Geological Survey national waterway study [139] showed that sheet flow and drainage, not deposition, dominated input to the waterbodies it surveyed. The commenter stated that sheet flow and drainage could contain Hg and thus complicate the relationship that EPA asserts is linear and direct. Another commenter cited Figure 2–17 in the Hg Risk TSD as showing that there is no well-defined relationship between Hg deposition and MeHg concentrations in fish tissue on a national basis.

Several commenters provided comments related to the assumption that fish tissue Hg levels used in the analysis represent a steady-state. One commenter stated that given the demonstrated lag time in response to deposition change, it is logical to conclude that a lag time needs to be incorporated in Mercury Maps to adjust the estimation of how much fish tissue MeHg levels decrease in response to decreases in Hg deposition attributable to U.S. EGUs. According to the same commenter, the METAALICUS study shows that there is a lag time (and a non-proportional response) after 3–4 years. The same commenter noted that there are numerous factors that influence lag time including (1) watershed characteristics,[140] (2) the fact that watersheds may act as legacy sources releasing Hg when disturbed,[141] (3) the magnitude of emission reductions and subsequent changes in atmospheric deposition need to be weighed against the amount of Hg already in an ecosystem,[142] (4) the distance of an ecosystem from Hg sources,[143] and (5) the fact that Hg deposited to aquatic ecosystems becomes less available for uptake by biota over time.[144] Another commenter stated that additional Mercury Maps assumptions do not allow for considerations of lag in response to changes in: (1) Deposition, (2) legacy sources of Hg such as mining, (3) historical Hg deposition, (4) natural Hg levels in fish, (5) ecosystem dynamics over time, or (6) the relative source contributions over time. Another commenter stated that lag times need to be included in the modeling and be able to vary from watershed to watershed and sometimes even from waterbody to waterbody within a watershed. Several commenters stated that the emission rates of Hg due to U.S. sources have been decreasing for more than a decade, while emissions due to sources outside the U.S. have been increasing. For this reason, the commenter asserted that the system is not at steady-state, a basic premise of the model. Another commenter stated that while the time lag for deposition to reach a waterbody is mentioned in the Hg Risk TSD, there is no discussion of the fact that a

[135] Seigneur *et al.*, 2006.

[136] *Id.*

[137] Harris., R.C., John W.M. Rudd, Marc Amyot, Christopher L. Babiarz, Ken G. Beaty, Paul J. Blanchfield, R.A. Bodaly, Brian A. Branfireun, Cynthia C. Gilmour, Jennifer A. Graydon, Andrew Heyes, Holger Hintelmann, James P. Hurley, Carol A. Kelly, David P. Krabbenhoft, Steve E. Lindberg, Robert P. Mason, Michael J. Paterson, Cheryl L. Podemski, Art Robinson, Ken A. Sandilands, George R. Southworth, Vincent L. St. Louis, and Michael T. TateRudd, J. W.M., Amyot M., *et al.*, Whole-Ecosystem study Shows Rapid Fish-Mercury Response to Changes in Mercury Deposition. Proceedings of the National Academy of Sciences Early Edition, PNAS 2007 104 (42) pp. 16586–16591; (published ahead of print September 27, 2007).

[138] Orihel D.M., Paterson M.J., Blanchfield P.J., Bodaly R.A., Gilmour C.C., Hintelmann H., 2007. "Temporal Changes in the Distribution, Methylation, and Bioaccumulation of Newly Deposited Mercury in an Aquatic Ecosystem," *Environmental Pollution*, 154, 77–88.

[139] Scudder B.C., Chasar L.C., Wentz D.A., Bauch N.J., Brigham M.E., Moran P.W., Krabbenhoft D.P., 2009. *Mercury in fish, bed sediment, and water from streams across the United States, 1998–2005:* U.S. Geological Survey Scientific Investigations Report 2009–5109, 74 p.

[140] Grigal D.F., 2002. "Inputs and Outputs of Mercury from Terrestrial Watersheds: A Review," *Environmental Review*, 10, 1–39.

[141] Yang H., Rose N.L., Battarbee R.W., Boyle J.F., 2002. "Mercury and Lead Budgets for Lochnagar, a Scottish Mountain Lake and Its Catchment," *Environmental Science & Technology*, 36, 1383–1388.

[142] Krabbenhoft D.P., Engstrom D., Gilmour C., Harris R., Hurley J., Mason R., 2007. Monitoring and Evaluating Trends in Sediment and Water Indicators. In Harris R., Krabbenhoft D., Mason R., Murray M.W., Reash R., Saltman T. (Eds.), *Ecosystem Responses to Mercury Contamination: Indicators of Change.* New York: Society of Environmental Toxicology and Chemistry (SETAC) North America Workshop on Mercury Monitoring and Assessment, CRC, pp. 47–87.

[143] Lindberg S. *et al.* 2007. "A synthesis of progress and uncertainties in attributing the sources of mercury in deposition." Ambio 36(1): 19–32.

[144] Orihel D.M., Paterson M.J., Blanchfield P.J., Bodaly R.A., Hintelmann H., 2008. "Experimental Evidence of a Linear Relationship between Inorganic Mercury Loading and Methylmercury Accumulation by Aquatic Biota," *Environmental Science & Technology*, 41, 4952–4958.

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portion of the deposition is unlikely to reach the water at all.

One commenter believes EPA incorrectly implied that its EGU risk estimates using Mercury Maps are underestimated because they do not account for legacy EGU-attributable deposition, which EPA assumes to be higher.

One commenter stated that while EPA properly screened out watersheds with significant current non-air sources of Hg, the EPA did not adequately screen out watersheds with significant Hg contributions from non-air sources, specifically watersheds with historic Hg or gold mining or other industrial Hg discharges. The same commenter stated that EPA's study was not geographically balanced and was dominated by rivers in the coastal region of the southeast that has numerous wetlands, which are favorable locations for methylation and have conditions that are not typical of much of the rest of the U.S.

Response: The EPA disagrees with the commenters who challenged the assumption of a linear proportional relationship between changes in U.S. EGU deposition and fish tissue Hg levels. The EPA specifically asked the SAB to evaluate EPA's assumption of linear proportionality in the relationship between Hg deposition and fish tissue MeHg concentrations, supported by the Mercury Maps analysis. The SAB peer review committee provided the following overall response, which generally supports EPA's approach:

> The SAB agrees with the Mercury Maps approach used in the analysis and has cited additional work that supports a linear relationship between mercury loading and accumulation in aquatic biota. These studies suggest that mercury deposited directly to aquatic ecosystems can become quickly available to biota and accumulated in fish, and reductions in atmospheric mercury deposition should lead to decreases in methylmercury concentrations in biota. The SAB notes other modeling tools are available to link deposition to fish concentrations, but does not consider them to be superior for this analysis or recommend their use. The integration of Community Multiscale Air Quality Modeling System (CMAQ) deposition modeling to produce estimates of changes in fish tissue concentrations is considered to be sound. Although the SAB is generally satisfied with the presentation of uncertainties and limitations associated with the application of the Mercury Maps approach in qualitative terms, it recommends that the document include quantitative estimates of uncertainty available in the existing literature.[145]

The SAB peer review committee specifically addressed the MCM suggested by the commenter and had the following response:

> The SAB agrees with the application of Mercury Maps in this assessment. There are other modeling tools capable of making a national scale assessment, such as the Regional Mercury Cycling Model (R–MCM). However, the R–MCM is more data intensive and the results produced by the two model approaches should be equivalent.
>
> The R–MCM, a steady-state version of the time-dependent Dynamic Mercury Cycling Model, has been publicly available to and used by the EPA (Region 4, Athens, Environmental Research Laboratory) for a number of years. R–MCM requires more detail on water chemistry, methylation potential, etc., and yields more information as well. Substantial data support the Mercury Maps and the R–MCM steady-state results, so that the results of the sensitivity analysis and the outcomes from using the alternative models would be equivalent between the two modeling approaches. Though running an alternative model framework may provide additional reassurance that the Mercury Maps "base case" approach is a valid one, it is unlikely that substantial additional insight would be gained with the alternative model framework.[146]

In addition, the SAB stated, "Since the Mercury Maps approach was developed, several recent publications have supported the finding of a linear relationship between mercury loading and accumulation in aquatic biota.[147] [148] [149] These studies suggested that mercury deposited directly to aquatic ecosystems can become quickly available to biota and accumulated in fish, and that reductions in atmospheric mercury deposition should lead to decreases in methylmercury concentrations in biota. These results substantiate EPA's assumption that proportionality between air deposition changes and fish tissue methylmercury level changes is sufficiently robust for its application in this risk assessment." [150]

Based on the responses of the SAB peer review committee, the EPA's use of the linear proportionality assumption, supported by the Mercury Maps analysis, is well-supported.

The EPA also disagrees with commenters' interpretation of Figure 2–17. As stated in the Hg Risk TSD, while this figure is useful to demonstrate the lack of correlation across watersheds between total deposition of Hg and MeHg concentrations in fish tissue, it is not indicative of the likely correlation between changes in Hg deposition at a given watershed and changes in MeHg concentrations in fish tissue from that watershed. The SAB agreed with this interpretation, noting the importance of Figure 2–17 demonstrating that "spatial variability of deposition rates is only one major driver of spatial variability of fish methylmercury and that variability of ecosystem factors that control methylation potential (especially wetlands, aqueous organic carbon, pH, and sulfate) also play a key role." [151]

In response to recommendations from the SAB, the EPA expanded the discussion of uncertainties associated with the linearity assumption, including uncertainties related to the potential for sampled fish tissue Hg level to reflect previous Hg deposition and the potential for non-air sources of Hg to contribute to sampled fish tissue Hg levels. Each of these sources of uncertainty may result in potential bias in the estimate of exposure associated with current deposition. The EPA took steps to minimize the potential for these biases by (1) only using fish tissue Hg samples from after 1999, and (2) screening out watersheds that either contained active gold mines or had other substantial non-U.S. EGU anthropogenic emissions of Hg. The SAB commented that EPA's approach to minimizing the potential for these biases to affect the results of the risk analysis appears to be sound and that additional criteria that could be applied are unlikely to substantially change the results. As a result, the EPA disagrees with the commenter that EPA's screening process is inadequate. In addition, we conducted several sensitivity analyses to gauge the impact of excluding watersheds with the potential for non-EGU Hg emissions, and found that the results were robust to these exclusions.

In response to specific comments regarding the use of the Mercury Maps model, the EPA clarifies that the Hg Risk TSD did not directly use the Mercury Maps model. Instead, the EPA applied an assumption of linear proportionality between changes in Hg deposition and changes in MeHg concentrations in fish that is supported by the Mercury Maps modeling. By assuming steady-state conditions in apportioning fish tissue Hg levels and risk, the EPA does not attempt to project lag times. Recent research cited by the SAB [152] [153] [154] identifies relatively rapid response of fish tissue Hg to changes in Hg loading, which suggests that fish tissue Hg levels could react more

[145] U.S. EPA–SAB, 2011.

[146] U.S. EPA–SAB, 2011.

[147] Orihel *et al.*, 2007.

[148] Orihel *et al.*, 2008.

[149] Harris *et al.*, 2007.

[150] U.S. EPA–SAB, 2011.

[151] U.S. EPA–SAB, 2011.

[152] Orihel *et al.*, 2007.

[153] Orihel *et al.*, 2008.

[154] Orihel *et al.*, 2007.

quickly to reductions in Hg deposition than previously thought. This finding reduces concern that fish tissue Hg levels could be linked to older patterns of Hg deposition and strengthens the approach used in the revised Hg Risk TSD. While fish tissue may respond rapidly to changes in Hg loading, this does not change the fact that previously emitted Hg from U.S. EGUs can be re-emitted and re-deposited, and thus affect Hg concentration in fish.

2. Characterization of Subsistence Fishing Populations and Exposure Scenario

Comment: Several commenters stated that EPA provides no clear definition of subsistence, near subsistence, or high-end fish consumption, instead assuming that poverty is a direct indication of subsistence fishing and high-end fish consumption. One commenter stated no documentation exists to supports these assumptions. Another commenter stated that EPA's definitions of subsistence fishers in the Hg Risk TSD are not consistent with earlier EPA documents and are used inconsistently throughout the Hg Risk TSD. Several commenters stated that while subsistence fishing can be associated with poverty, poverty does not indicate subsistence fishing. One commenter stated that by including watersheds with as few as 25 members of individuals living in poverty, the EPA overstates risks.

One commenter stated that it is unclear what literature the Agency says "generally supports the plausibility of high-end subsistence-like fishing * * * to some extent across the watersheds" and stated that if other studies exist, the EPA should provide the values for comparison.

One commenter stated that EPA combined two parameters with differing scales to establish the geographic unit used in the Hg Risk TSD risk assessment. The HUC watersheds are based on average about 35 square miles in size, while U.S. census tracts used to identify watersheds relevant for subpopulations of interest—cover a few tenths to hundreds of square miles. Several commenters stated that it is unclear how the analysis handled differences in geographic resolution between watersheds and census tracts were.

One commenter stated that the procedure for assigning census tracts could bias exposure outcomes. For example, the commenter stated that a single influential census tract in a watershed could drive risk, even if the watershed had only a minimal number of fish samples. The commenter stated that this possibility is a concern in urban areas, which account for the majority of census tracts, because these census tracts are more likely to be included in a risk analysis because they have more than 25 people living in poverty. The commenter stated that these census tracts may drive the extremes of the distribution without regard to the actual number of high-level, self-caught fish consumers within their boundaries. The commenter stated that they could not assess the potential bias and noted that EPA did not test the bias by sensitivity analyses.

Several commenters stated that EPA was not clear whether the poverty criteria were applied in all scenarios or just for the high-end female fish consumer scenario. One commenter stated that EPA should apply the minimum 25 source population criteria only to populations of women of childbearing age. One commenter stated that EPA's assumption would result in any densely populated urban census tract with a single fish tissue sample being assigned to a modeled watershed with populations potentially at-risk, regardless of the actual degree of recreational or subsistence fishing taking place there.

Response: The EPA agrees with the comments that subsistence fish consumption was not clearly defined, and we have provided a clearer definition in the revised Hg Risk TSD, however, this clarification does not result in any changes to the quantitative analysis. In the revised Hg Risk TSD, the EPA clarifies that "subsistence fishers" are defined as individuals who rely on noncommercial fish as a major source of protein.[155] This definition is reflected in the range of fish consumption rates used in estimating risk. The likely presence of this type of subsistence fish consumer is supported by available peer reviewed literature (*see* Table 1–5 of the revised Hg Risk TSD). These studies clearly show that a subset of surveyed fishers consumes self-caught fish at the rates cited in the Hg Risk TSD. The SAB peer review concluded that the consumption rates and locations for fishing activity are supported by the data presented in the Hg Risk TSD, and are generally reasonable and appropriate given the available data.[156]

The EPA notes that there is some confusion in the comments related to the size of the watersheds modeled. Several commenters stated that HUC watersheds are 35 km on a side. The commenters appear to be referring to HUC8 classifications. The HUCs are defined for varying spatial resolutions. The geographic unit used as the basis for generating risk estimates is HUC12, which are watersheds about 10 km on a side, which is comparable with the size of the 12 km^2 grid cells in CMAQ, which are 12 km^2. The EPA has also clarified that the specific unit of analysis for this assessment is at the watershed, not enumerated subpopulations.

The EPA only used the U.S. Census tracts to determine whether there are populations in the vicinity of a given watershed, which could increase the potential for a category of subsistence fishers to be active at that watershed. In the revised Hg Risk TSD, the EPA modified the female subsistence scenario to apply equally to all watersheds with fish tissue Hg data based on the likelihood that these populations have the potential to fish at most watersheds. As described in the revised Hg Risk TSD, the EPA made this change in response to SAB's concerns regarding the potential exclusion of watersheds with fewer than 25 individuals and regarding coverage for high-end recreational fish consumption.[157] Thus, concerns regarding the use of census data to select watersheds with the potential for subsistence fishing no longer apply to this scenario. However, for the remaining subsistence scenarios, the EPA continues to use U.S. Census tract-level data to evaluate the presence of a "source population" in the vicinity of the watershed being modeled for risk. In this context, the EPA uses the U.S. Census data to assess whether a socioeconomic status (SES)-differentiated group similar to the particular type of subsistence fisher being modeled (*e.g.*, poor Hispanics) are located in the vicinity of the watershed. If a source population is nearby, then this increases the potential that subsistence fishing activity could occur for that population scenario.

The EPA continues to model risk for white and black subsistence fishers active in the southeast and for Hispanics assessed nationally. In this case, the EPA links poverty with subsistence fishing, as EPA only modeled locations with poor source populations. However, in modeling these three populations, the

[155] U.S. EPA, U.S. Environmental Protection Agency. 2000. *Guidance for Assessing Chemical Contaminant Data for Use in Fish Advisories,* Volume 3: Overview of Risk Management. Office of Science and Technology, Office of Water, U.S. Environmental Protection Agency, Washington, DC EPA 823–B–00–007.

[156] U.S. EPA–SAB, 2011.

[157] This change led to a very small increase in the number of watersheds with populations potentially at-risk. In the Hg Risk TSD accompanying the proposed rule, approximately 4 percent of modeled watersheds were excluded based on the SES-based filtering criteria.

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EPA asserts that the presence of a poor source population indicates the potential for subsistence fishing activity, rather the presence of such activity. The linkage between poverty and higher rates of subsistence fish consumption is supported by the Burger *et al.* study,[158] which identified substantially higher consumption rates for poor individuals (*see* Table 5 of the study). The EPA acknowledges that subsistence fishing activity by specific subpopulations might only be present across a subset of the watersheds EPA modeled for risk. However, given the stated goal of the analysis to determine the percent of watersheds where the potential exists for exposures to U.S. EGU-attributable Hg to represent a public health hazard, identifying a set of watersheds with the potential for the type of high fish consumption that leads to high Hg exposure is appropriate. The EPA notes that relatively few watersheds (less than 4 percent) have fish tissue Hg data, and, thus, can be included in the risk assessment. Consequently, while there is the potential for including some watersheds in the analysis that may not have currently active subsistence fishing activity, it is likely that EPA excluded other watersheds from the analysis where this type of subsistence fishing activity occurs due to a lack of fish tissue Hg data.

While EPA agrees with the comment that it is likely that exposure to total MeHg through commercial fish consumption represents a more significant risk for the general population than consumption of freshwater fish obtained through self-caught fishing activity, exposure to total MeHg through self-caught fish consumption is the most significant risk for subsistence fishing populations and high-end recreational fishers. For the subset of these populations that focus their fishing activity in freshwater streams and lakes, it is also the case that they will experience a higher fraction of MeHg exposure attributable to U.S. EGU Hg emissions. As a result, the EPA focused the risk assessment on subsistence fishers active at inland freshwater watersheds because they are likely to experience the highest levels of individual risk as a result of exposure to U.S. EGU-attributable Hg.

3. Cooking Loss Adjustment Factor

Comment: Several commenters stated that EPA did not justify the selection of a cooking loss factor of 1.5 that, according to one commenter, increases estimated intake by 50 percent, thus increasing the daily MeHg intake rate by a constant factor of 33 percent and also increasing any resulting (HQ) risk estimate by a similar factor. Several commenters stated that the source of EPA's selected loss factor[159] reported a range of cooking losses from 1.1 to 6. Several commenters cite several studies that report no or highly variable changes in MeHg levels as a result of cooking fish.[160] [161] [162] [163] [164] One commenter suggested that EPA's cooking loss adjustment factor of 1.5 is at the high-end of the values supported by the literature. Another commenter stated that EPA has used other adjustment factors in previous documents, and that the adjustment factor should not be fixed across different populations given potential differences in cooking practices. Several commenters noted that the cooking loss adjustment factor should only be applied to estimates of consumption rates for prepared fish, and that some sources of consumption rates are based on raw fish.

Response: The EPA disagrees with the commenters that the selection of the cooking loss factor of 1.5 is not justified by the literature. The EPA also disagrees with the comment that the cooking loss adjustment factor of 1.5 is at the high-end of the range of values in the literature. The EPA selected the Morgan study[165] as the basis for the food preparation/cooking adjustment factor because it focused on the types of freshwater fish species representative of what might be consumed by subsistence fishing populations (*i.e.,* walleye and lake trout). This study[166] provides a range of adjustment factors for each fish type including 1.1 to 1.5 for walleye and 1.5 to 2.0 for lake trout. Given these two ranges, the EPA determined it to be reasonable to take an intermediate value between the two ranges (*i.e.,* 1.5), rather than focus on either the highest or lowest values, which is not the most conservative assumption that the EPA could have made. This study[167] also explains that preparation/cooking of fish results in an increase in MeHg levels per unit fish because Hg concentrates in the muscle, while preparation/cooking tends to reduce non-muscle elements (*e.g.,* water, bone, fat).

Regarding the alternative studies identified by the commenters, the EPA disagrees that these studies considered collectively contradict the cooking loss factor in the analysis. Specifically, the first study[168] may have included measurement of non-fish components added to dishes (*e.g.,* onions, heavy breading etc.), which could dilute the post-cooking Hg measurements and give the appearance of a cooking loss even as actual fish tissue Hg levels could have increased. In the second study,[169] the fish species are saltwater and not freshwater, and the authors note that the reduction of water and fat could increase in the Hg concentration without changing absolute content. The third study focused on measurement of *bioaccessible Hg* in raw and cooked fish.[170] However, available information currently allows us to specify the risk model in terms of total Hg intake, not bioaccessible Hg, thus, this article is potentially informative for guiding future research and methods development, not the current risk assessment. The fourth study[171] found a modest but statistically insignificant increase in Hg levels for most of the cooking methods assessed, which is directionally consistent with EPA's cooking loss adjustment. The fifth study[172] only addressed the issue qualitatively, thus cannot be used for the cooking loss factor. When considered collectively, the EPA disagrees that the additional studies identified by the commenter contradict the cooking loss factor used in the risk assessment and maintains that the Morgan study[173] remains the most

[158] Burger, J., 2002. "Daily Consumption of Wild Fish and Game: Exposures of High End Recreationists," *International Journal of Environmental Research and Public Health,* 12 (4), 343–54.

[159] Morgan, J.N., M.R. Berry, and R.L. Graves. 1997. "Effects of Commonly Used Cooking Practices on Total Mercury Concentration in Fish and Their Impact on Exposure Assessments." *Journal of Exposure Analysis and Environmental Epidemiology* 7(1):119–133.

[160] Armbruster G., Gerow K.G., Lisk D.J., 1988. "The Effects of Six Methods of Cooking on Residues of Mercury in Striped Bass," *Nutrition Reports International,* 37, 123–126.

[161] Gutenmann, W.H. and Lisk D.J., 1991. "Higher Average Mercury Concentration in Fish Fillets after Skinning and Fat Removal," *Journal of Food Safety,* 11, 99–103.

[162] Farias L.A., Favaro, D.I., Santos J.O., Vasconcellos M.B., *et al.,* 2010. "Cooking Process Evaluation on Mercury Content in Fish," *Acta Amazonia,* 40 (4), 741–748.

[163] Perelló G., Martí-Cid R., Llobet J.M., Domingo J.L., 2008. "Effects of Various Cooking Processes on the Concentrations of Arsenic, Cadmium, Mercury, and Lead in Foods," *Journal of Agricultural and Food Chemistry,* 156 (22), 11262–11269.

[164] Torres-Escribano S., Ruiz A., Barrios L., Vélez D., Montoro R., 2011. "Influence of Mercury Bioaccessibility on Exposure Assessment Associated with Consumption of Cooked Predatory Fish in Spain," *Journal of the Science of Food and Agriculture,* 91 (6), 981–6.

[165] Morgan *et al.,* 1997.

[166] *Id.*

[167] *Id.*

[168] Farias *et al.,* 2002.

[169] Perelló *et al.,* 2008.

[170] Torres-Escribano *et al.,* 2011.

[171] Armbruster *et al.,* 1988.

[172] Gutenmann *et al.,* 1991.

[173] Morgan *et al.,* 1997.

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applicable for characterizing cooking/preparation effects on Hg concentrations in fish.

The EPA agrees that application of the cooking loss adjustment factor is appropriate if the fish consumption rates are for *as cooked* or *as consumed* and not for raw fish. Careful review of the three studies used in the risk assessment to identify subsistence fisher consumption rates suggests that all three represent annual-average daily intakes (g/day) of *as consumed* or *as cooked* fish. One study stated that they used models of portion or meal size servings (the size of the serving the respondent regularly eats).[174] Therefore, the EPA interprets the fish consumption rates provided in this study[175] as representing *as cooked/prepared* and not for raw fish and for that reason, application of a preparation/cooking adjustment factor is required. Another study[176] used different sized models of cooked fish filets and therefore these consumption rates are also interpreted as represented *as cooked/prepared* and not raw fish. One study[177] [178] queried survey responders for meal portion or serving size and therefore, the consumption rates do represent *as cooked/prepared.* Because all three studies provide consumption rates based on *as cooked/prepared* or as consumed, it is appropriate to apply the cooking loss adjustment factor in modeling exposure.

4. Fish Consumption Rates and Fish Tissue Hg Characterization

Comment: One commenter stated that in the past the Agency has recommended various default consumption rates (in the general range of 130 to <150 g/day) to provide default intakes for subsistence fishers under the *Risk Assessment Guidance for Superfund (RAGS) or the Fish Advisory Guidance.*[179] [180] The commenter stated that these default consumption rates are derived from various studies and generally are based on 90th or 99th percentile distribution estimates. Another commenter stated that EPA's use of the 99th percentile fish consumption for its risk analysis is inconsistent with the Agency's risk assessment guidelines, which recommend evaluating a reasonable maximum exposure ("RME") scenario,[181] which equates to about a 95th percentile fish consumption value. The same commenter stated that EPA applied the 99th percentile to a "small survey of 149 South Carolina female anglers" to calculate an ingestion rate of 373 grams per day (g/day). The commenter stated that if the 95th percentile is used the ingestion rate would be 173 g/day and if the default ingestion rate for determining ambient water standards is used the ingestion rate would be 142 g/day.

Several commenters stated that EPA based its fish consumption rates used in the risk analysis on a limited number of studies and that those studies are poorly documented.

Another commenter stated that EPA should summarize available supporting studies by basic study content, characteristics, design, size, demographics, dietary recall period, and fish intake rates by demographic variables. According to the commenter, this summary would support the scientific validity of the assessment and better illustrate the potential variability and uncertainty involved in extrapolating data from small populations to the national-scale. The commenter also noted that the three studies actually used to provide subsistence population estimates, which were extrapolated to the national-scale, included a limited number of individuals living in diverse and localized areas.

One commenter stated that the assumption with the greatest impact on risk is the fish consumption rate. That same commenter stated that using 99th percentile ingestion rate dramatically increases HQ and IQ loss compared to the 50th percentile ingestion rate. The commenter stated that when an estimate of the 95th percentile ingestion rate of the 15 to 44 year old female population is considered, the HQ is a tenth of the value computed with the 99th percentile high-end female fisher.

One commenter stated that EPA provides broad summary statistics of its fish tissue data in Table 5–2 of the Regulatory Impact Analysis (RIA), but the summary does not allow an assessment of the representativeness and robustness of the underlying data for the risk assessment, especially at the tails of the distribution. The commenter stated that the table does not include a median statistic and does not provide any information on the number of lakes and river segments in each watershed. According to the commenter, an analysis of EPA's database by the SAB indicated that 60 percent of the watersheds with fish Hg data from rivers have risks calculated based upon a sample size of one or two fish. The commenter stated that it is not reasonable to base a significant policy and regulation decision on watersheds where exposure is based on a single fish sample in a single water body within it.

Several commenters criticized EPA's use of the 75th percentile fish tissue MeHg level in a watershed. One commenter stated that EPA provided no rationale for its decision to choose the highest of the 75th percentile for fish Hg levels among rivers and lakes within the HUC. Several commenters stated that subsistence fishers are less likely to target larger fish relative to recreational fishers. Several commenters suggested that EPA include a sensitivity analysis using the mean or median fish MeHg level in a watershed. One commenter also stated that EPA arbitrarily inflated the risk estimates by assuming consumption of only fish greater than 7 inches and choosing the largest of the 75th percentile of fish Hg levels from these larger fish (*i.e.,* larger than 7 inches) for rivers and lakes. That same commenter suggested using the median of all size fish, not just those over 7 inches.

One commenter stated that EPA should quantify adverse effects from the ingestion of MeHg in seafood in addition to ingestion of MeHg from self-caught freshwater fish. According to the commenter, recent studies demonstrate that were EPA to take into account consumption of seafood, MeHg consumption in the U.S. is of even greater concern.

Response: The EPA acknowledges that the focus of the Hg Risk TSD is characterizing risk for the groups likely to experience the greatest U.S. EGU-attributable Hg risk, which are subsistence fishing populations active at inland freshwater lakes and rivers. Specifically, within that subsistence fishing population, the EPA is interested in those individuals who are most at-risk, which includes those who consume the most fish. For that reason, the EPA considered a range of high-end fish consumption rates including the 99th percentile representing the most highly-exposed individuals. In responding to the SAB peer review, the EPA clarified this focus in the

[174] Burger *et al.,* 2002.

[175] *Id.*

[176] Shilling, Fraser, Aubrey White, Lucas Lippert, Mark Lubell (2010). Contaminated fish consumption in California's Central Valley Delta. Environmental Research 110, p. 334–344.

[177] Dellinger JA. 2004. "Exposure assessment and initial intervention regarding fish consumption of tribal members of the Upper Great Lakes Region in the United States." *Environ Res* 95:325–340.

[178] Personal communication, Dr. Dellinger, September 27, 2011.

[179] U.S. EPA. 1991. *Risk Assessment Guidance for Superfund (RAGS).* Part C 1991 EPA/9285.7–01C. October.

[180] U.S. EPA. 2000. *National Guidance: Guidance for Assessing Chemical Contaminant Data for Use in Fish Advisories,* Volume 2. EPA 823–B–00–008, November.

[181] U.S. EPA. 1989. *Risk Assessment Guidance for Superfund (RAGS).* EPA/540/1–89/002. December.

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introduction to the revised Hg Risk TSD and changed the full title to *revised Technical Support Document: National-Scale Assessment of Mercury Risk to Populations with High Consumption of Self-caught Freshwater Fish.*

The EPA agrees that the fish consumption rate is an important factor in calculating risk from exposure to MeHg in fish. The EPA acknowledges that the distribution of fish consumption rates is positively skewed, which means that at higher percentiles (*e.g.,* 90th, 95th, and 99th) there is a substantial increase in ingestion rates relative to the mean or median. The revised Hg Risk TSD includes a reasonableness check on the amount of fish consumed (as a daily value) reflected in the different rates. While the 99th percentile consumption rates for the subsistence female fisher (373 g/day) is substantially higher than the 90th or 95th percentile values (123 and 173 g/day respectively), the 99th percentile value translates into a 13-ounce meal. While this represents a large serving, it is still reasonable if representing an individual who receives all of their meat protein from self-caught fishing, and the 13 ounces per day do not have to be eaten all at one meal. The higher consumption rates (i.e., greater than 250 g/day) are supported by all three studies used in the risk assessment, and therefore, there is support across studies near the upper bound of likely consumption rates in this range. The EPA acknowledges uncertainty associated with estimating high-end percentile values in these studies due to relatively low sample sizes for some population groups. However, even if a few individuals reported these high self-caught fish consumption rates, making it difficult to characterize the population percentiles they represent, the values still suggest that these levels of high fish consumption exist among surveyed individuals. To determine whether a public health hazard could exist, the EPA asserts that it is reasonable to include these consumption rates as representative of the most at-risk populations. In these cases, however, the EPA acknowledges that it is important to highlight uncertainty associated with characterizing the specific population percentile that these ingestion rates represent, and EPA has done so in the revised Hg Risk TSD.

The EPA disagrees with the comment that high consumption rates are poorly documented. Evidence of these high fish consuming populations can be found in surveys [182] and specialized studies.[183] [184] [185] [186] [187] Several studies identified additional fishing populations with subsistence or near subsistence consumption rates, including urban fishing populations (including low-income populations),[188] [189] [190] Laotian communities,[191] and Hispanics. The EPA participated in 1999 in a project investigating exposures of poor, minority communities in New York City to a number of contaminants including Hg, which found these populations can have very high fish consumption rates.[192] The SAB concluded that the consumption rates and locations for fishing activity are supported by the data presented in the Hg Risk TSD, and are generally reasonable and appropriate given the available data.[193]

The EPA agrees that the Hg Risk TSD would be improved by clarifying that the literature review focused on identifying studies that characterize subsistence fish consumption for groups active at freshwater locations within the U.S., and EPA has revised the Hg Risk TSD accordingly. In the Hg Risk TSD, the EPA summarized important study attributes for the source studies used to obtain fish consumption rates. This information was provided in Table C–1 in an appendix. To improve clarity, the EPA moved the summary table to the main body in the revised Hg Risk TSD. In identifying these studies, the EPA focused on surveys for subsistence fishers that were applicable at the broader regional or national level. In the Hg Risk TSD, the EPA acknowledged the smaller sample sizes for some of the subsistence fisher groups, and in several cases the EPA did not use the 99th percentile consumption rates because the sample sizes were too low to support this level of resolution. This decision did not affect EPA's finding of a hazard to public health, which is based on the results for the female subsistence fishing population, which has an estimate of the 99th percentile consumption rate that is supported by an adequate sample size.

The EPA disagrees with the comment that it did not provide a rationale for choosing the 75th percentile fish tissue concentration across lakes and rivers in a watershed. However, the EPA modified the methodology based on evaluation of the number of samples within each watershed (responding to a recommendation from the SAB). In the revised methodology, the EPA computes the 75th percentile value at each sampling site within a watershed. The EPA then computed the average of the site-specific 75th percentile fish tissue Hg values within a given watershed. This approach does not differentiate between rivers and lakes and reflects an improved treatment of behavior, allowing for fishers to choose among multiple fishing sites within a watershed.

The EPA generally agrees with the comment that some fraction of subsistence fishers likely consume fish without consideration for size (given dietary necessity), however, the EPA considers it reasonable to assume that a subset of subsistence fishers could target larger fish in order to maximize the potential consumption per unit of fishing effort. The EPA uses this subset of subsistence fishers targeting larger fish, which is represented by the 75th percentile fish tissue value, in the risk assessment. In addition, including the female subsistence fishing population in the analysis also provides coverage for high-end recreational anglers who target larger freshwater fish. The SAB commented that: "Using the 75th percentile of fish tissue values as a reflection of consumption of larger, but not the largest, fish among sport and subsistence fishers is a reasonable approach and is consistent with published and unpublished data on predominant types of fish consumed." [194] The SAB suggested that EPA include a sensitivity analysis based on use of the median value, and EPA has done so in the revised Hg Risk TSD. This sensitivity analysis showed that using the median estimates had only a small impact on the number and percent of modeled watersheds with

[182] Burger *et al.,* 2002.

[183] Burger, J., K. Pflugh, L. Lurig, L. Von Hagen, and S. Von Hagen. 1999a. "Fishing in Urban New Jersey: Ethnicity Affects Information Sources, Perception, and Compliance." *Risk Analysis* 19(2): 217–229.

[184] Burger, J., Stephens, W. L., Boring, C. S., Kuklinski, M., Gibbons, J. W., Gochfeld M. 1999b. "Factors in Exposure Assessment: Ethnic and Socioeconomic Differences in Fishing and Soncumption of Fish Caught along the Savannah River." *Risk Analysis,* Vol. 19, No. 3, p. 427.

[185] California Environmental Protection Agency (CalEPA). 1997. *Chemicals in Fish Report No. 1: Consumption of Fish and Shellfish in California and the United States Final Draft Report.* Pesticide and Environmental Toxicology Section, Office of Environmental Health Hazard Assessment, July.

[186] Tai, S. 1999. "Environmental Hazards and the Richmond Laotian American Community: A Case Study in Environmental Justice." Asian Law Journal 6: 189.

[187] Corburn, J. 2002. "Combining community-based research and local knowledge to confront asthma and subsistence-fishing hazards in Greenpoint/Williamsburg, Brooklyn, New York." *Environmental Health Perspectives* 110(2).

[188] Burger *et al.,* 1999a.

[189] Burger *et al.,* 1999b.

[190] CalEPA, 1997.

[191] Tai, 1999.

[192] Corburn, 2002.

[193] U.S. EPA–SAB, 2011.

[194] U.S. EPA–SAB, 2011.

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populations potentially at-risk from U.S. EGU-attributable MeHg exposures. In the revised Hg Risk TSD, the EPA clarified that the 7-inch cutoff represents a minimum size limit for a number of key edible freshwater fish species established at the State-level. For example, Pennsylvania establishes 7 inches as the minimum size limit for both trout and salmon (other edible fish species such as bass, walleye and northern pike have higher minimum size limits).[195]

The EPA disagrees with the comment that it is not reasonable to use watersheds where only a single fish sample is available. Although it is generally preferred to have multiple samples, the SAB noted that using a single sample is likely to underestimate the 75th percentile fish MeHg concentration and is, therefore, likely to underestimate the risk estimates for those watersheds. The SAB suggested that EPA conduct additional analyses of the fish tissue MeHg data, which EPA has done and included in the revised Hg Risk TSD. The revised Hg Risk TSD includes information on the number of watersheds modeled in the risk assessment with various fish tissue Hg samples sizes (e.g., 1, 2, 3–5, 6–10 and >10 measurements).

5. Reference Dose (RfD) for MeHg and Hg Health Effects Studies

Comment: Several commenters stated that EPA's RfD[196] is based on sound science, which was supported by the findings of the NAS Study,[197] and that EPA appropriately applied the RfD in the Hg risk assessment. The commenters also stated that recent studies find clear associations between maternal blood Hg levels and delayed child development and cardiovascular effects, as well as potential for effects due to exposure to pollutant mixtures including lead.

However, many commenters expressed concerns regarding EPA's use of the MeHg RfD as a benchmark for health risk. Several commenters raised concerns claiming that EPA has not incorporated the best available Hg toxicological data into the RfD, which results in a flawed analysis and an overestimate of the impact of Hg emissions on human health.

Several commenters stated that, when deriving the RfD, the EPA relied on the flawed Faroe Islands' children study and ignored the Seychelles Islands study,[198] which did not confirm any harm on children due to MeHg exposure. According to the commenters, application of the Faroe Island study is suspect because (1) the raw data from the study have never been made available for independent analysis and scrutiny, (2) there is potential for confounding by polychlorinated biphenyls (PCBs) and lead, (3) population exposure to MeHg was through consumption of highly contaminated pilot whale meats and blubbers, and (4) exposure levels in the U.S. remain lower than those observed in the primary study. One commenter also notes that (1) Seychelles Islanders consume far more fish than Americans do; (2) the amount of MeHg in the U.S. population is much lower than the Seychelles Islanders; and (3) all ocean fish contain about the same amount of MeHg, so MeHg intake per fish meal is similar between Americans and Seychelles Islanders. However, another commenter stated that industry arguments against using the Faroe Islands study fail to acknowledge that the study results were consistent with studies in the Seychelles Islands, New Zealand,[199] and Poland.[200]

One commenter criticized EPA for using a linear dose-response model for the RfD-based HQ metric and the IQ metric. Another commenter stated that the RfD assumes a threshold dose below which an appreciable risk of adverse effects is unlikely, and NAS did not evaluate whether MeHg exposure data were better fit by a linear or non-linear model or by a threshold or non-threshold model.

Several commenters stated that EPA's MeHg RfD is more conservative than "safe" levels determined by other federal agencies and claim that EPA assigned unusually high uncertainty factors. Several commenters stated that EPA's use of the 1999 National Health and Nutrition Examination Survey (NHANES) blood Hg levels show a downward trend since 1999, and the levels have been below the RfD since 2001.

One commenter stated that a study by Texas Department of State Health Services (DSHS, 2004)[201] determined that among subsistence fishers who eat fish from Caddo Lake with elevated MeHg, women of child-bearing years did not have blood Hg levels greater than the RfD. Thus, according to the commenter, the connection between MeHg in fish and adverse health effects in the U.S. is not fully understood and could involve other factors, including the protective effects of fatty acids and selenium in fish, which EPA did not taken into account.

Two commenters claim that EPA uses the RfD as if it were an absolute threshold for health risk in the risk assessment even though the RfD methodology is a screening tool for deciding when risks clearly do not exist.

Several commenters recommended adding qualitative discussions to the Hg Risk TSD regarding several aspects of uncertainty, including uncertainty in the RfD, uncertainty in extrapolating a dose-response relationship between MeHg exposure and change in IQ, uncertainty in extrapolating the dose-response relationship from marine fish and marine mammals to freshwater fish, and uncertainty due to potential confounding by PCBs in marine species.

Several commenters raised concerns regarding the relationship between MeHg exposure and IQ loss. Two commenters stated that changes in IQ are not a well-defined health consequence of MeHg exposure. One commenter stated that the SAB had reservations about EPA's use of IQ loss. Two commenters questioned whether IQ impacts would even occur because in Japan and Korea, where the maternal blood Hg levels are higher than in the U.S., there is no evidence of adverse effects. Another commenter cited a study[202] that found verbal IQ scores for children from mothers with no seafood intake were 50 percent more likely to be in the lowest quartile. One commenter questions using an IQ risk metric threshold of >1 or >2 points because variation in IQ measures and the intra-individual variation in IQ are higher than the threshold.

Several commenters question the relationship between cardiovascular effects and MeHg exposure. Two

[195] Pennsylvania Fish and Boat Commission. 2011. *Summary Book: 2011 Pennsylvania Fishing Laws & Regulations* available at: *http://fishandboat.com/fishpub/summary/inland.html.*

[196] U.S. Environmental Protection Agency—Integrated Risk Information System (U.S. EPA–IRIS). 2001. Methylmercury (MeHg) (CASRN 22967–92–6). Available at *http://www.epa.gov/iris/subst/0073.htm.*

[197] NAS, 2000.

[198] Budtz-Jorgensen E, Debes F, Weihe P, Grandjean P. 2005. "Adverse Mercury Effects in 7–Year-Old Children Expressed as Loss in "IQ"." EPA–HQ–OAR–2002–0056–6046.

[199] Kjellstrom, T; Kennedy, P; Wallis, S; *et al.* 1986. *Physical and mental development of children with prenatal exposure to mercury from fish. Stage 1: Preliminary test at age 4.* Natl Swed Environ Protec Bd, Rpt 3080 (Solna, Sweden).

[200] Wieslaw Jedrychowski *et al.* 2006. "Effects of Prenatal Exposure to Mercury on Cognitive and Psychomotor Function in One-Year-Old Infants: Epidemiologic Cohort Study in Poland," 16 Annals of Epidemiology 439.

[201] DSHS. 2005. *Health Consultation: Mercury Exposure Investigation Caddo Lake Area-Harrison County Texas.* Agency for Toxic Substances and Disease Registry. *http://www.tceq.state.tx.us/assets/public/comm_exec/pubs/sfr/085.pdf.*

[202] Hibbeln JR, Davis JM, Steer C, Emmett P, Rogers I, Williams C, *et al.*, 2007. "Maternal seafood consumption in pregnancy and neurodevelopmental outcomes in childhood (ALSPAC study): an observational cohort study. " Lancet 369:

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commenters cited studies examining the relationship between MeHg exposure and cardiovascular effects,[203] [204] [205] [206] [207] [208] but concluded that it seems premature to use these studies to establish a dose-response relationship.

Several commenters assert that the risks from eating seafood are low relative to the benefits, that fish advisories can limit the beneficial aspects of fish consumption, and that fish advisories are often unsuccessful in changing behavior.[209] [210] One commenter noted the important protective role of dietary selenium against MeHg toxicity because the binding affinity of Hg to Se is much higher than binding to sulfur.

Response: The EPA agrees with commenters that state the MeHg RfD is the appropriate health value for determining elevated risks from MeHg exposure and disagrees with commenters that state otherwise. At this time, the EPA is neither reviewing nor revising its 2001 RfD for MeHg. The 2001 RfD for MeHg is EPA's current peer-reviewed RfD, which is the value EPA uses in all its risk assessments. The EPA's RfD is based on multiple benchmark doses, and RfDs were calculated on various endpoints using the three extant large studies of childhood effects of in utero exposure: Faroe Islands, New Zealand, and an integrative measure including data from Seychelles. The EPA did not choose to base the MeHg RfD solely on results from the Seychelles Islands, as both the NAS[211] and an independent scientific review panel convened as part of the IRIS process[212] advised strongly against using results from a study that at the time had not shown an association between MeHg exposure and adverse effects. Further, the EPA disagrees with comments stating that EPA based the MeHg RfD solely on results from the Faroe Islands population and disagrees that the information underlying the RfD is "poorly explained". The EPA has provided detailed documentation for the choices underlying calculation of the RfD.[213] [214] [215] To correct a misunderstanding by the commenter, the data underlying the Faroe Islands study have been previously published in the peer reviewed literature.

The EPA disagrees that it did not incorporate the latest Hg data to support the appropriate and necessary finding. It is the policy of EPA to use the most current peer reviewed, publicly available data and methodologies in its risk assessments. However, the EPA noted in the preamble to the proposed rule that "data published since 2001 are generally consistent with those of the earlier studies that were the basis of the RfD, demonstrating persistent effects in the Faroe Island cohort, and in some cases associations of effects with lower MeHg exposure concentrations than in the Faroe Islands. These new studies provide additional confidence that exposures above the RfD are contributing to risk of adverse effects, and that reductions in exposures above the RfD can lead to incremental reductions in risk." However, the EPA has not completed a comprehensive review of the new literature, and as such, it would be premature to draw conclusions about the overall implications for the RfD.

The EPA agrees that EPA's RfD is not the same as the levels used by other federal agencies. In their advice to the EPA on the appropriate bases for a MeHg RfD, NAS specifically recommended that EPA use neither the study nor the uncertainty factor employed by the Agency for Toxic Substances Disease Registry (ATSDR) in the calculation of the minimal risk level.[216]

The EPA disagrees that the uncertainty factor is "unusually high". The uncertainty factor used in calculation of EPA's peer-reviewed RfD is small (10 fold); half of this factor is to account for measured variability in human pharmacokinetics, which is based on advice of the NAS[217] and an independent panel of scientific peer reviewers convened as part of the IRIS process.[218]

The IRIS makes this statement regarding a threshold for MeHg, "It is also important to note that no evidence of a threshold arose for methylmercury-related neurotoxicity within the range of exposures in the Faroe Islands study. This lack [of a threshold] is indicated by the fact that, of the K power models, K = 1 provided a better fit for the endpoint models than did higher values of K."[219]

The EPA disagrees that it is using the MeHg RfD as an absolute bright line for health effects in the risk assessment. As stated in the preamble to this proposed rule, the RfD is an estimate of a daily exposure to the human population that is likely to be without an appreciable risk of deleterious effects during a lifetime. The EPA also stated that no RfD defines an exposure level corresponding to zero risk. Because mercury is a cumulative neurotoxin, it is important to distinguish health effects from public health hazard. Within the context of the appropriate and necessary finding, we interpret a public health hazard as risk, rather than certain occurrence of health effects.

The EPA disagrees that exposure levels in the U.S. are lower than those in the Faroe Islands study. Exposure to MeHg in the U.S. has been reported at the same levels as those published in the Faroe Islands.[220] One study notes that in the NHANES data (1999 to 2004), the highest five percent of women's blood Hg exceeded 8.2 microgram per liter (μg/L) in the Northeast U.S. and 7.2 μg/L in coastal areas.[221] Higher levels have been reported among subjects known to consume fish. For example, one study reported mean blood Hg for adult women to be 15 μg/L; range for

[203] Roman HA, Walsh TL, Coull BA, Dewailly É, Guallar E, Hattis D, *et al.,* 2011. Evaluation of the Cardiovascular Effects of Methylmercury Exposures: Current Evidence Supports Development of a Dose–Response Function for Regulatory Benefits Analysis. Environ Health Perspect 119:607–614.

[204] Guallar E, Sanz-Gallardo MI, van't Veer P, *et al.,* 2002. "Mercury, fish oils, and the risk of myocardial infarction." N Engl J Med.;347:1747.

[205] Virtanen JK, Voutilainen S, Rissanen TH, *et al.,* 2005. "Mercury, fish oils, and risk of acute coronary events and cardiovascular disease, coronary heart disease, and all-cause mortality in men in eastern Finland." Arterioscler Thromb Vasc Biol. 2005;25:228.

[206] Yoshizawa, Rimm, Morris, Spate, Hsieh, Spiegelman, Stampfer, Willett. "Mercury and the Risk of Coronary Heart Disease in Men," N Engl J Med 2002; 347:1755–1760.

[207] Hallgren CG, Hallmans G, Jansson JH, *et al.,* 2001. Markers of high fish intake are associated with decreased risk of a first myocardial infarction. Br J Nutr: 86:397.

[208] Mozaffarian, Dariush. 2011. "Mercury Exposure and Risk of Cardiovascular Disease in Two U.S. Cohorts," N Engl J Med 364: 1116–1125.

[209] Hibbeln *et al.,* 2007.

[210] Mozaffarian, *et al.,* 2011.

[211] NAS, 2000.

[212] U.S. EPA. 2001b. Responses to Comments of the Peer Review Panel and Public Comments on Methylmercury. Available on the Internet at *http://www.epa.gov/iris/supdocs/methpr.pdf.*

[213] U.S. EPA, 2001a. Water Quality Criterion for the Protection of the Human Health: MethylmercuryEPA–823–T–01–001, available at *http://water.epa.gov/scitech/swguidance/standards/criteria/aqlife/pollutants/methylmercury/index.cfm.*

[214] U.S. EPA–IRIS, 2001.

[215] Rice D, Schoeny R, Mahaffey K. 2003. "Methods and Rationale for Derivation of a Reference Dose for Methylmercury by the U.S. EPA." Risk Analysis 23(1)107–115.

[216] NAS, 2000.

[217] Id.

[218] U.S. EPA, 2001b.

[219] U.S. EPA–IRIS, 2001.

[220] Schober Susan E, Sinks Thomas H, Jones Robert L, Bolger P Michael, McDowell Margaret, Osterloh John, Garrett E Spencer, Canady Richard A, Dillon Charles F, Sun Yu, Joseph Catherine B, Mahaffey Kathryn R. Blood mercury levels in U.S. children and women of childbearing age, 1999–2000. JAMA. 2003 Apr 2; 289(13): 1667–1674.

[221] Mahaffey, K.R., R.P. Clickner and R.A. Jeffries. 2009. Adult Women's Blood Mercury Concentrations Vary Regionally in the U.S.: Association with Patterns of Fish Consumption (NHANES 1999–2004). *Environ. Health Perspect.,* 117: 47–53.

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men and women was 2 to 89.5 µg/L.[222] Note that some publications have reported Hg effects in U.S. populations at or below the current U.S. RfD.[223] [224] Also, the EPA disagrees with the commenter stating all ocean fish throughout the world contain about the same amount of MeHg. Marine fish in commerce differ widely in Hg concentration by species, and fish within the same species but caught at different locations have variable amounts of Hg in their tissues.[225] [226]

The EPA disagrees that there is a statistically discernible downward trend in the NHANES data on blood Hg. The EPA is unaware that a formal statistical analysis for temporal trends has been completed for NHANES data on blood Hg levels for the period 1999 to 2008. Mahaffey*et al.*, evaluating NHANES data collected 1999 to 2004 for women at child-bearing age, could "not support the conclusion that there was a general downward trend in blood Hg concentrations over the 6-year study period." [227] However, the same publication noted that "there was a decline in the upper percentiles reflecting the most highly exposed women" having blood Hg concentration greater than established levels of concern. Visual observations of the data show a slight decrease in Hg blood level concentrations from 1999–2008 at the geometric mean, but this decrease may not be statistically significant. The EPA remains concerned that substantial numbers of women of childbearing age in the U.S. may have blood Hg levels that are equivalent to exposures at or above the RfD. While mean and 95th percentiles from recent NHANES data are below the blood Hg concentration equivalent to the RfD, blood levels for some portions of the population (high consumers of fish, for example) show exposures above this level. One study estimated very high blood Hg levels at the 99th percentile for females of child-bearing age.[228] Other published studies have shown that various population groups can have high blood Hg levels.[229] [230] [231] [232] [233] For example, one study found that 83 percent of the NHANES Asian population exceeded the RfD-equivalent blood mercury level.[234]

The EPA disagrees with the commenter regarding confounding by PCBs and lead. Exposure to MeHg in the Faroe Islands was largely from consumption of pilot whale meat; exposure to PCBs was found in the portion of the population who also consume whale blubber. Numerous analyses have shown neurobehavioral effects of PCBs; however, the effects of MeHg and PCB in the Faroe Islands study are separable.[235] The EPA also documented the independence of PCB and MeHg effects in the Faroe Islands population.[236] The National Institute of Environmental Health Sciences (NIEHS) concluded that both PCB and Hg had adverse effects.[237] The NAS concluded that there was no empirical evidence or theoretical mechanism to support the opinion that *in utero* Faroese exposure to PCBs exacerbated the reported MeHg effect.[238] A second set of analyses found that the effect of prenatal PCB exposure was reduced when the data were sorted into tertiles by cord PCB concentrations.[239] These analyses support a conclusion that there are measurable effects of MeHg exposure in the Faroese children that are not attributable to PCB toxicity. We also note that there was no report of lead exposure in the Faroe Islands population.

The EPA disagrees with the commenter's assertion that the connection between MeHg in fish and observed health effects is not understood due to evidence from the cited Texas study.[240] This is an exposure study rather than a study on measures of neurobehavioral or any other health endpoint. TCEQ noted that none of the Caddo Lake study participants had blood Hg levels above the benchmark dose level (BMDL) of 5.8 µg/L (one of the several used by EPA in the calculation of the MeHg RfD). The BMDL is not a "no effect" level. Rather it is an effect level for a percentage of the population. The EPA has noted in correspondence with TCEQ that, as an exposure study, the Caddo Lake study may be representative of the surrounding population; however, the sample size is very small. It is not appropriate to extrapolate from Caddo Lake to larger regional or national populations.

The EPA is aware of the possibility of both interactions among environmental contaminants and cumulative effects of pollutants that produce the same adverse endpoint. The EPA guidance exists for dealing with such scenarios.[241] [242] [243] [244] The Agency's concern with the likelihood of human exposure to multiple contaminants is

[222] Hightower Jane M, Moore Dan. Mercury levels in high-end consumers of fish. Environ Health Perspect. 2003 Apr; 111(4): 604–608.

[223] Oken, E., Radesky, J.S., Wright, R.O., Bellinger, D.C., Amarasiriwardena, C.J., Kleinman, K.P., Hu, H., Gillman, M.W. 2008. Maternal fish Intake during Pregnancy, Blood Mercury Levels, and Child Cognition at Age 3 Years in a U.S. Cohort. *American Journal of Epidemiology, 167(10),* 1,171–1,181.

[224] Lederman, Sally Ann Robert L. Jones, Kathleen L. Caldwell, Virginia Rauh, Stephen E. Sheets, Deliang Tang, Sheila Viswanathan, Mark Becker, Janet L. Stein, Richard Y. Wang, and Frederica P. Perera. 2008. Relation between Cord Blood Mercury Levels and Early Child Development in a World Trade Center Cohort. *Environmental Health Perspectives* 118(8) 1085–1091.

[225] Hisamichi Y, Haraguchi K, Endo T. 2010. "Levels of mercury and organochlorine compounds and stable isotope ratios in three tuna species taken from different regions of Japan." *Environ Sci Technol* 44(15): 5971–8.

[226] Sunderland EM. 2007. "Mercury exposure from domestic and imported estuarine and marine fish in the U.S. seafood market." *Environ Health Perspect.* 115(2): 235–42. Epub 2006 Nov 20.

[227] Mahaffey, K.R., R.P. Clickner and R.A. Jeffries. 2009. Adult Women's Blood Mercury Concentrations Vary Regionally in the U.S.: Association with Patterns of Fish Consumption (NHANES 1999–2004). *Environ. Health Perspect.,* 117: 47–53.

[228] Tran, N.L., L. Barraj, *et al.,* 2004. "Combining food frequency and survey data to quantify long-term dietary exposure: a methyl mercury case study." *Risk Anal* 24(1): 19–30.

[229] *Id.*

[230] Miranda, M.L., S. Edwards, *et al.,* 2011. "Mercury levels in an urban pregnant population in Durham County, North Carolina." *Int J Environ Res Public Health* 8(3): 698–712.

[231] Hightower and Moore, 2003.

[232] Hightower, J.M., A. O'Hare, *et al.,* (2006). "Blood mercury reporting in NHANES: identifying Asian, Pacific Islander, Native American, and multiracial groups." Environ Health Perspect 114(2): 173–175.

[233] McKelvey, W., R.C. Gwynn, *et al.,* 2007. "A biomonitoring study of lead, cadmium, and mercury in the blood of New York city adults." Environ Health Perspect 115(10): 1435–1441.

[234] Hightower*et al.,* 2006.

[235] NAS, 2000.

[236] U.S. EPA, 2001a.

[237] National Institute of Environmental Health Sciences (NIEHS). 1998. Scientific issues relevant to assessment of health effects from exposure to methylmercury. Workshop organized by Committee on Environmental and Natural Resources (CENR) Office of Science and Technology Policy (OSTP), The White House, November 18–20, 1998, Raleigh, NC.

[238] NAS, 2000.

[239] Budtz-Jørgensen, E., N. Keiding, and P. Grandjean. 1999. Benchmark modeling of the Faroese methylmercury data. Final Report to U.S. EPA.

[240] DSHA, 2005.

[241] U.S. EPA. 1986. *Guidelines for the Health Risk Assessment of Chemical Mixtures.* U.S. Environmental Protection Agency, Office of Research and Development, Washington, DC September. EPA/630/R–98/002. Available at *http://cfpub.epa.gov/ncea/cfm/recordisplay.cfm?deid=2256.*

[242] U.S. EPA. 1999. *Guidance for Perfarming Aggregate Exposure and Risk Assessments.* U.S. Environmental Protection Agency, Office of Pesticide Programs, Washington, DC October. Available at *http://www.pestlaw.com/x/guide/1999/EPA-19991029A.html.*

[243] U.S. EPA. 2000a. *Supplementary Guidance for Conducting Health Risk Assessment of Chemical Mixtures.* U.S. Environmental Protection Agency, Risk Assessment Forum, Washington, DC EPA/630/R–00/002. Available at *http://www.epa.gov/ncea/raf/pdfs/chem_mix/chem_mix_08_2001.pdf.*

[244] U.S. EPA. 2003a. Framework for Cumulative Risk Assessment. Risk Assessment Forum, U.S. Environmental Protection Agency. Washington, DC EPA/630/P–02/001F. EPA/600/P–02/001F. Available at *http://cfpub.epa.gov/ncea/cfm/recordisplay.cfm?deid=54944.*

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reflected in the multi-chemical scope of the rulemaking. However, the EPA focused the technical analyses supporting the proposed regulation on effects of individual pollutants rather than cumulative effects.

The EPA disagrees with commenters suggesting that the RfD-based HQ is inappropriate. The SAB "agreed that EPA's calculation of a hazard quotient for each watershed included in the assessment is appropriate as the primary means of expressing risk," and that "because the RfD from which the HQ is calculated is an integrative metric of neurodevelopmental effects of methylmercury, it constitutes a reasonable basis for assessing risk." [245]

The SAB also recommended that EPA revise the Hg Risk TSD to include additional qualitative discussion about uncertainty in the revised Hg Risk TSD. Specifically, the SAB recommended that EPA revise the Hg Risk TSD "to better explain the methods and choices made in the analysis, and analytical results, and where the uncertainties lie." The SAB noted several uncertainties related to the RfD. The EPA agrees with this recommendation and included a more complete discussion of these uncertainties in the revised Hg Risk TSD.

The EPA disagrees that the IQ metric threshold is questionable. The SAB concluded that it was reasonable to consider a loss of >1 or >2 IQ points a public health concern. The SAB stated, "The Panel agreed that if IQ loss is retained in the risk assessment despite these reservations, a loss of one or two points would be an appropriate benchmark." [246] The SAB further comments in their report: "The consensus is that if IQ were to be used, then a loss of 1 or 2 points as a population average is a credible decrement to use for this risk assessment. This metric seems to be derived from the lead literature and was peer reviewed by the Clean Air Scientific Advisory Committee (U.S. EPA CASAC 2007).[247] Although its applicability to methylmercury is questionable, the size of the decrement is justified based on the extensive analyses available from the literature reviewed by CASAC." [248] As noted in other studies,[249] [250] a decrease of 1–2 points at the mean results in a much larger decrease in those with IQs that are much lower or higher than the mean.

Although EPA disagrees that the IQ results are too uncertain to rely upon, the EPA acknowledges that IQ is not the most sensitive neurodevelopmental endpoint affected by MeHg exposure, as also noted by the SAB. The SAB recommended that the IQ analyses be retained but be de-emphasized in the documentation underlying the final regulation. The SAB concluded, "The Panel does not consider it appropriate to use IQ loss in the risk assessment and recommended that this aspect of the analysis be de-emphasized, moving it to an appendix where IQ loss is discussed along with other possible endpoints not included in the primary assessment. While the Panel agreed that the concentration-response function for IQ loss used in the risk assessment is appropriate, and no better alternatives are available, IQ loss is not a sensitive response to methylmercury and its use likely underestimates the impact of reducing methylmercury in water bodies." [251] The EPA is following the SAB's recommendation by deemphasizing the IQ analysis and placing that analysis in an appendix to the revised Hg Risk TSD.

The SAB, however, supported the use of the IQ dose-response function calculated by EPA in the Hg Risk TSD. The SAB noted, "The function used came from a paper by Axelrad and Bellinger (2007) that seeks to define a relationship between methylmercury exposure and IQ. A whitepaper by Bellinger (Bellinger, 2005) [252] describes the sequence of steps in relating methylmercury exposure to maternal hair mercury and then that to IQ. The Mercury Risk TSD furthers notes that IQ has shown utility in describing the health effects of other neurotoxicants. These are appropriate bases for examining a potential impact of reducing methylmercury on IQ, but the SAB does not consider these compelling reasons for using IQ as a primary driver of the risk assessment." [253]

The EPA disagrees that the Agency has overstated or failed to review the scientific literature on cardiovascular effects from MeHg exposure. As summarized in the preamble to the proposal, the EPA stated that the NAS study concluded that "Although the data base is not as extensive for cardiovascular effects as it is for other end points (*i.e.,* neurologic effects) the cardiovascular system appears to be a target for MeHg toxicity in humans and animals." [254] The EPA also stated that additional cardiovascular studies have been published since 2000. The EPA did not develop a quantitative dose response assessment for cardiovascular effects associated with MeHg exposures, as there is no consensus among scientists on the dose-response functions for these effects, and there is inconsistency among available studies as to the association between MeHg exposure and various cardiovascular system effects. In the future, the EPA may update the MeHg RfD and will review all of the relevant scientific literature available at that time, including data on all relevant endpoints, and weight of evidence for likelihood that MeHg produces specific effects in humans.

The EPA acknowledges the research regarding the effectiveness of fish advisories. However, the proposed regulation does not address the subject of fish advisories, consumer advice on fish or efficacy of such advice. The EPA rejects the commenter's speculation regarding whether the estimated IQ impacts for the regulation are real. Adverse effects of *in utero* Hg exposure have been reported in populations in the U.S.[255] [256] In another study on neurobehavioral effects of prenatal exposure to MeHg through maternal consumption of seafood, adverse effects are observed for MeHg even without controlling for fish consumption.[257] That study suggests that at normal Japanese dietary intake of MeHg and fish nutrients, the overall effect is adverse. While Japanese fish consumption and Hg exposure are both somewhat higher than the mean U.S. exposure, these levels are still within the distribution of U.S. consumers.

[245] U.S. EPA–SAB, 2011.

[246] U.S. EPA–SAB, 2011.

[247] U.S. Environmental Protection Agency—Science Advisory Board (U.S. EPA–SAB). 2007. *Clean Air Scientific Advisory Committee's (CASAC) Review of the 1st Draft Lead Staff Paper and Draft Lead Exposure and Risk Assessments.* EPA–CASAC–07–003. March. Available on the internet at *http://yosemite.epa.gov/sab/sabproduct.nsf/989B57DCD436111B852572AC0079DA8A/$File/casac-07-003.pdf.*

[248] U.S. EPA–SAB, 2011.

[249] Axelrad, D. A.; Bellinger, D. C.; Ryan, L. M.; Woodruff, T. J. 2007. "Dose-response relationship of prenatal mercury exposure and IQ: An integrative analysis of epidemiologic data." *Environmental Health Perspectives,* 115, 609–615.

[250] Bellinger DC. 2005. *Neurobehavioral Assessments Conducted in the New Zealand, Faroe Islands, and Seychelles Islands Studies of Methylmercury Neurotoxicity in Children.* Report to the U.S. Environmental Protection Agency. EPA–HQ–OAR–2002–0056–6045.

[251] U.S. EPA–SAB, 2011.

[252] Bellinger, 2005.

[253] U.S. EPA–SAB, 2011.

[254] 76 FR 25001.

[255] Oken *et al.,* 2008.

[256] Lederman *et al.,* 2008.

[257] Suzuki, K., Nakai, K., Sugawara, T., Nakamura, T., Ohba, T., Shimada, M., Hosokawa, T., Okamura, K., Sakai, T., Kurokawa, N., Murata, K., Satoh, C., and Satoh, H. 2007. "Neurobehavioral effects of prenatal exposure to methylmercury and PCBs, and seafood intake: neonatal behavioral assessment scale results of Tohoku study of child development." *Environ Res* 110, 699–704.

Moreover, many studies show that beneficial effects of fish on both cardiovascular and neurodevelopmental health are decreased by concomitant exposure to MeHg. Several studies describe one or more aspects of exposure to fish nutrients and MeHg.[258] [259] [260] [261] [262] [263] [264] Recent studies [265] [266] [267] and analyses indicate the potential for nutrients in fish (particularly marine fish) to mask some of the observed adverse effects of MeHg. Because EPA did not adjust for potential confounding by nutrients in marine fish and mammals, the benchmark doses used in the RfD derivation may be underestimated.

The EPA recognizes the potential for confounding of the effects of Hg on the developing nervous system by a range of nutrients and discusses this uncertainty in the revised Hg Risk TSD. Regarding selenium, the SAB commented that "one SAB member suggests the use of blood markers of selenium-dependent enzyme function, noting that methylmercury irreversibly inhibits selenium-dependent enzymes that are required to support vital-but-vulnerable metabolic pathways in the brain and endocrine system. Impaired selenoenzyme activities would be observed in the blood before they would be observed in brain, but the effect is also expected to be transitory. The use of these measures is a minority view among the SAB members." [268] The SAB did not express a consensus recommendation on adjustments to the risk estimates for exposure to selenium or other nutrients, noting that "there is not enough known about their quantitative impact to support a recommendation of a re-analysis." [269]

6. General Comments on Hg Risk Assessment

Comment: Several commenters generally supported the Hg risk assessment, but several other commenters generally disagreed with the Hg risk assessment. One supporter stated that EPA reasonably determined that Hg emissions pose a public health hazard, correctly requested peer review of Hg risk analysis and correctly concluded EGU-attributable MeHg poses a hazard to public health at watersheds when considering all sources of Hg deposition and U.S. EGUs alone. Two commenters noted that the contribution of U.S. EGUs to total Hg deposition can significantly contribute to hundreds of watersheds, and U.S. EGU deposition alone may endanger sensitive populations near many of these watersheds.

Several commenters claimed that overly conservative assumptions in the risk analysis render the results flawed and unreliable, including using CMAQ to model deposition, Mercury Maps, fish consumption rate and fish MeHg concentrations, overly stringent RFD, national-scale model, using poverty as a surrogate for subsistence fishing, assuming a subsistence fisher resides in most watersheds with fish tissue data, fishers only eat larger fish with high Hg concentrations, cooking loss adjustment, unrealistically high fish ingestion rates (a large fish meal every day), focused on the extremes of the distributions, cast many assumptions as an underestimate of the effect despite evidence to the contrary, and created inappropriate metrics for risk that show no improvement despite significant Hg emissions reductions in the U.S.

Several commenters cite Tetra Tech's analysis that assessed Hg risk using different consumption rates, cooking factor, mean fish tissue concentrations, and EGU-attributable Hg deposition only, which showed considerably fewer watersheds that exceed an HQ of 1 at 2016 deposition levels.

Several commenters claim that this regulation would not significantly reduce Hg exposure via fish consumption because EGU-attributable deposition is a small fraction of total deposition. One commenter stated that EPA's data shows Hg emissions from U.S. EGUs have little influence on fish Hg concentrations despite a reduction of 41 tons of Hg in the U.S. between 2005 and 2016. One commenter requested that EPA accurately describe the low health risks posed by utility hazardous air pollutant emissions. One commenter stated that EPA did not consider scientific information showing that there is no straightforward connection between Hg emissions from U.S. EGUs to the Hg level in fish, which is dependent upon many environmental factors, such as sunlight and organic matter, pH, water temperature, sulfate, bacteria, and zooplankton present in the ecosystem. One commenter stated that there is not any demonstrable evidence that anyone in the U.S. has suffered adverse health problems as a result of Hg emissions from coal-fired EGUs. One commenter stated that EPA's findings are similar to the 2000 findings where EPA found a plausible link between anthropogenic emissions of Hg from sources in the U.S. and MeHg in fish, and "plausible" is a euphemism for unproven.

Several commenters had recommendations for the Hg risk analysis. One commenter stated that more data from Florida should have been included because Florida is known to have a rich data set on fish Hg concentrations. One commenter stated that EPA should characterize general recreational angler fishers instead of subsistence fishers. One commenter claims that EPA made math errors in the Hg Risk TSD regarding the deposition in watersheds at specific percentiles. One commenter questioned EPA's policy metrics used to characterize Hg risk.

Several commenters stated that the Hg TSD is unclear and lacks detail, as noted by the SAB. One commenter stated that the SAB is critical of EPA's efforts, stating that the SAB found it difficult to evaluate the risk assessment based solely upon Hg Risk TSD and recommended that EPA transparently explain the methods and uncertainties. One commenter stated that because of insufficient review time and the lack of detail in the Hg Risk TSD, they could not assess key questions, such as the nation-wide representativeness of the fish tissue data.

One commenter stated the subset of watersheds considered in the analysis (*i.e.*, with fish tissue data) have clearly higher U.S. EGU-attributable deposition than the distribution of all watersheds.

One commenter stated EPA's reporting of IQ point loss is erroneous and not relevant to informing policy, and the U.S. EGU contribution to risk is marginal as evidenced by the null values for the 50th percentile watershed.

One commenter notes that U.S. EGU-attributable emissions of Hg have decreased significantly between 2005

[258] Grandjean P, Bjereve K, Wihe P, and Sterewald u. 2001a. "UBirthweight in a fishing community: significance of essential fatty acids and marine food contaminants." *In. J. Epidemiol.* 30:1272–1278.

[259] Budtz-Jorgensen, E.; Grandjean, P.; Weihe, P. 2007. "Separation of risks and benefits of 16 seafood intake." *Environmental Health Perspectives.* Vol. 115, 323–327.

[260] Choi *et al.*, 2008a.

[261] Choi *et al.*, 2008b.

[262] Oken *et al.*, 2008.

[263] Strain, J.J. *et al.*, 2008. Associations of maternal long chain polyunsaturated fatty acids, methyl mercury, and infant development in the Seychelles Child Development Nutrition Study." *Neurotoxicology.* 29(5): 776–782.

[264] Suzuki, *et al.*, 2007.

[265] Oken *et al.*, 2008.

[266] Choi AL, Cordier S, Weihe P, Grandjean P. 2008a. "Negative confounding in the evaluation of toxicity: the case of methylmercury in fish and seafood." *Crit Rev Toxicol.* 2008;38(10):877–93.

[267] Choi AL, Budtz-Jørgensen E, Jørgensen PJ, Steuerwald U, Debes F, Weihe P, Grandjean P. 2008b. "Selenium as a potential protective factor against mercury developmental neurotoxicity." *Environ Res.* May;107(1):45–52. Epub 2007 Sep 12.

[268] U.S. EPA–SAB, 2011.

[269] *Id.*

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and 2016, but claims that this decrease does not appear to affect the risk results.

Response: The purpose of the Hg risk assessment is not to assess the magnitude of risk reduction under the proposed rule, but rather to estimate the magnitude of absolute risk attributable to U.S. EGUs currently and following implementation of other applicable CAA requirements. That said, any potential risk reductions following implementation of the MACT rule itself would likely reflect a number of factors besides the national average U.S. EGU deposition value cited by the commenter. These additional factors include: (a) Spatial gradients in the magnitude of absolute U.S. EGU-attributable Hg deposition, (b) spatial gradients in the magnitude of reductions in Hg deposition linked to the rule, (c) availability of measured fish tissue Hg levels in the vicinity of U.S. EGUs experiencing larger Hg emission reductions to support risk modeling, and (d) the potential for subsistence fishing activity at watersheds in the vicinity of U.S. EGUs experiencing larger reductions in Hg emissions (also required to support risk modeling). It is also important to point out that while the national average U.S. EGU-attributable Hg deposition (for the 2016 scenario—see revised Hg Risk TSD) is two percent, values range up to 11 percent for the 99th percentile watershed. This illustrates the substantial spatial variation in U.S. EGU-attributable Hg deposition, which translates into spatial variation in the magnitude of U.S. EGU-attributable subsistence fisher risk.

The SAB conducted a comprehensive peer review of all of EPA's assumptions in the Hg Risk TSD, and concluded that "the SAB supports the overall design of and approach to the risk assessment and finds that it should provide an objective, reasonable, and credible determination of the potential for a public health hazard from Hg emitted from U.S. EGUs." [270] Furthermore, the SAB concluded, "The SAB regards the design of the risk assessment as suitable for its intended purpose, to inform decision-making regarding an "appropriate and necessary finding" for regulation of hazardous air pollutants from coal and oil-fired EGUs, provided that our recommendations are fully considered in the revision of the assessment." [271] Although the SAB did indicate difficulty in evaluating the risk assessment based solely on the Hg Risk TSD, the panel obtained additional information from EPA through the peer review process and determined that "the SAB supports the overall design of and approach to the risk assessment and finds that it should provide an objective, reasonable, and credible determination of the potential for a public health hazard from mercury emitted from U.S. EGUs." [272] The primary advice of the SAB panel was that EPA should "revise the Technical Support Document to better explain the methods and choices made in the analysis, and analytical results, and where the uncertainties lie." [273] The EPA has revised the Hg Risk TSD as part of the final rulemaking to address the SAB's recommendations and has made that revised Hg Risk TSD available in the rule docket.

The SAB concurred with EPA's analytical assumptions and overall study design for the Hg Risk TSD, including the RfD-based HQ approach, fish tissue data, 75th percentile size fish, Mercury Maps assumption, and consumption rates. Based on the SAB peer review, the EPA strongly disagrees with commenter statements that the results reported in the Hg Risk TSD are unreliable, overly conservative, extreme, inconsistent with EPA risk guidelines, or severely overstate risk based on the stated objectives of the analysis. The EPA has specifically addressed each of these assumptions in the previous sections of the preamble, and thus, does not repeat those responses here. Based on the review by the SAB, the EPA has accurately described the health risks posed by utility hazardous air pollutant emissions and disagrees with the commenter's statement that EPA has not provided any demonstrable evidence to show that adverse health risks exist. The EPA has applied peer reviewed modeling to estimate the deposition of Hg attributable to U.S. EGUs. The EPA asserts that these metrics demonstrate a clear hazard to public health from Hg emissions from U.S. EGUs.

The EPA thoroughly evaluated the Tetra Tech analysis. The EPA does not agree that the analysis by Tetra Tech uses assumptions that are "more reasonable", and the SAB agreed that all of EPA's assumptions in the Hg Risk TSD are reasonable and appropriate. The EPA asserts that Tetra Tech's analysis does not fully cover subsistence fishers likely to experience elevated U.S. EGU-related Hg exposure. Specifically, the risk estimate cited in the comment reflects application of a number of behavioral assumptions that provide significantly less coverage for higher risk subsistence fishers. Fish consumption surveys cited in the revised Hg Risk TSD suggest that higher percentile subsistence fishers eat more than twice the level of fish assumed by Tetra Tech. Tetra Tech's analysis also used the median fish tissue levels, but it is reasonable to assume that subsistence fishers would target somewhat larger fish to maximize the volume of edible meat per unit time spent fishing. Tetra Tech's analysis also assumed that cooking fish did not concentrate Hg, but a number of studies discussed in the revised Hg Risk TSD explicitly provide adjustment factors involving a higher unit concentration following preparation. Taken together, Tetra Tech's analysis does not address the stated goal of the risk assessment to assess the nature and magnitude of risk for those individuals likely to experience the greatest risk associated with exposure to U.S. EGU-attributable Hg.

The EPA disagrees with the commenter's assertion that this rule will not affect risks associated with Hg exposure. Hg from U.S. EGUs contributes to the levels of MeHg in fish across the country and consumption of contaminated fish can lead to increased risk of adverse health effects. The EPA has shown in the RIA (Chapter 5) that this rule will reduce Hg levels in fish.

The EPA acknowledges that U.S. EGUs contribute only a small fraction of total Hg deposition in the U.S. However, U.S. EGUs remain the largest emitter of Hg in the U.S., and the revised Hg Risk TSD shows that U.S. EGU-attributable Hg deposition results in up to 29 percent of modeled watersheds with populations potentially at-risk. Our analyses show that of the 29 percent of watersheds with population at-risk, in 10 percent of those watersheds U.S. EGU deposition alone leads to potential exposures that exceed the MeHg RfD, and in 24 percent of those watersheds, total potential exposures to MeHg exceed the RfD and U.S. EGUs contribute at least 5 percent to Hg deposition. Mercury risk is increasing for exposures above the RfD, and as a result, any reductions in Hg exposures in locations where total exposures exceed the RfD can result in reduced risks. While these reductions in risk may be small for most populations and locations, in some watersheds and for some populations, reductions in risk may be greater.

The SAB also directly addressed the question of the nation-wide representativeness of the fish tissue MeHg data in the national Hg risk assessment. The SAB concluded, "Although the SAB considers the number of watersheds included in the assessment adequate, some watersheds

[270] U.S. EPA–SAB, 2011.

[271] *Id.*

[272] *Id.*

[273] *Id.*

in areas with relatively high mercury deposition from U.S. EGUs were under-sampled due to lack of fish tissue methy[l]mercury data. The SAB encourages the Agency to contact states with these watersheds to determine if additional fish tissue methylmercury data are available to improve coverage of the assessment." [274] In response to the SAB's recommendations, the EPA obtained additional fish tissue sample data from several states, particularly Pennsylvania, Wisconsin, Minnesota, New Jersey, and Michigan. This additional data increased the total number of watersheds assessed in the analysis by 33 percent nationally. In Florida, the EPA assessed the Hg-related health risk for 40 watersheds. Because EPA did not find any additional fish tissue data for watersheds in Florida that could be incorporated into the analysis, the total number of watersheds in Florida assessed in the revised Hg Risk TSD remains the same as the Hg Risk TSD at proposal.

The EPA disagrees with the commenter that there were errors in the Hg Risk TSD. Instead, the commenter has misinterpreted how EPA calculated the percentiles. The percentile (and mean) values presented in Table ES–1 for total and U.S. EGU-attributable Hg deposition are not matched by watershed. In other words, the EPA queried for the percentiles (and mean) provided for total Hg deposition and presented those percentiles and then separately estimated the percentiles for U.S. EGU-attributable Hg. Therefore, the total and U.S. EGU-attributable values for the 99th percentile do not necessarily occur at the same watershed. The EPA has provided additional clarification in the revised Hg Risk TSD.

The EPA agrees with the commenter that MeHg levels in fish depend on a complicated set of environmental factors, and EPA acknowledged this in the revised Hg Risk TSD. Furthermore, the EPA acknowledges that total Hg fish tissue levels are not correlated with levels of total Hg deposition when looking across watersheds because this relationship is highly dependent on the methylation potential at the specific waterbody, which is affected by pH, sulfate deposition, turbidity, etc. However, several recent studies [275] [276] [277] show, and the SAB agrees, that it is appropriate for EPA to assume that changes in Hg deposition are linearly associated with *changes* in fish tissue concentration. In addition, the EPA agrees that the subset of watersheds in the risk analysis have somewhat higher U.S. EGU deposition than the distribution of all watersheds, but EPA disagrees that oversampling of high deposition watersheds is inappropriate.

The EPA does not agree that there is no improvement in fish Hg concentrations between 2005 and 2016, or that there will be no further improvement from decreasing Hg emissions from U.S. EGUs from the baseline in 2016. Although total risk from all Hg exposures will remain elevated in much of the U.S., much of that risk is associated with global, non-U.S. Hg emissions. U.S. EGUs remain the largest source of Hg emissions in the U.S., and reductions in those emissions will result in reduced Hg deposition in many highly impacted watersheds. As shown in the revised Hg Risk TSD, average U.S. EGU-attributable fish tissue Hg concentrations is estimated to decrease by 44 percent between 2005 and 2016. Although we did not remodel risk for the 2005 scenario in the revised Hg Risk TSD, we estimated at proposal that the total percent of modeled watersheds with populations potentially at-risk from Hg emissions from U.S. EGUs exceeding either risk metric (*i.e.*, U.S. EGUs alone or total potential exposures to MeHg exceed the RfD and U.S. EGUs contribute at least 5 percent) would decline from 62 percent in 2005 to 28 percent in 2016. This projected decline is primarily due to a combination of additional pollution control technologies installed to comply with federal regulations, such as CSAPR, and changing fuels, such as the shift to natural gas.

The EPA disagrees that IQ loss is erroneous or irrelevant to informing policy, but EPA has moved that analysis to an appendix in the revised Hg Risk TSD, per the SAB's recommendation. The EPA disagrees that the IQ effects at the 50th percentile watershed are useful in determining that there is not a hazard to public health because EPA's stated goal of the risk assessment was to focus on populations likely to experience relatively higher exposures to U.S. EGU-attributable Hg.

We also disagree with those commenters that point to the SAB's statements concerning the clarity of the Hg Risk TSD to suggest that the public did not have an ample opportunity to comment on the Hg risk assessment. Although it is correct that the SAB said the Hg Risk TSD was difficult to evaluate until EPA staff explained it at the public meeting in June 2011, we note that the commenters that assert that this issue amounts to a violation of CAA section 307(d) notice requirements made detailed technical comments, including many of the same comments as the SAB. Furthermore, the EPA provided notice of the peer review in the preamble to the proposed rule and a number of **Federal Register** notices advised the public of the peer review process and all the meetings were open to the public for comment and participation and the minutes of those meetings were posted on the SAB Web site. The minutes for the June 2011 meeting, during which EPA provided clarifying information, were available well within the public comment period for the proposed rule. For these reasons, we maintain that the public was provided an adequate opportunity to comment on the Hg risk assessment.

e. Non-Hg HAP Case Studies

1. Emissions for Non-Hg Case Studies

Comment: The commenters raised concerns about a wide variety of aspects of EPA's approach for emissions used for the non-Hg case studies, including the use of an arithmetic mean for computing emission factors for representing emissions of untested units, the suggestion of statistical outliers in the Cr test data, the claim that metals content of the fuel is an indicator of flawed test data, the statistical approaches used by EPA to create emission factors, the absence in EPA's approach of an equation that commenters claim better represents emissions values, that EPA's approach to estimate Cr(VI) is flawed, and the lack of coal rank as a delineating factor for emission factor calculation. The commenters also suggested that EPA should revise stack parameters used for the case studies based on better available data.

Response: In response to the comments on the emission factors, the EPA has undertaken additional analysis to address all commenter concerns. The EPA disagrees with commenter's criticisms of emission factors based on arithmetic means, and EPA demonstrates that the use of an arithmetic mean provides the most representative result. The EPA analysis has found that the geometric mean approach recommended by the commenter always under predicts actual emissions by an average of more than seventy percent. The EPA agrees with commenters' recommendations to use statistical outlier tests, but has applied tests different from those suggested by the commenters. As further explained in the response to comments document in the docket, this approach did not eliminate the Cr test data from the Cr

[274] U.S. EPA–SAB, 2011.
[275] Orihel *et al.*, 2007.
[276] Orihel *et al.*, 2008.
[277] Harris *et al.*, 2007.

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emission factors used for some of the case study emissions.

The EPA disagrees with commenters' assertions that the metal content of the coal is a basis for invalidating the test results of high Cr emissions. The identification of sources whose measured emissions do not match the commenters' preconceived idea of emissions behavior is not surprising. There are many possible explanations for these differences. For example, the inconsistency between the test data and the coal analysis could be due to any number of reasons including unrepresentative coal sampling, control device problems, degradation of the refractory, or sampling contamination. The idea that test data should be discarded because it does not match initial expectations is unfounded.

The EPA disagrees with the commenter recommendations for using an equation from AP–42, developed in part by the commenters. Based on analyses of metal emissions measured at the site compared to statistically predicted estimates, the EPA concluded that measured emissions test data better predict actual emissions, and emission factors based on the arithmetic mean are a reasonable method to estimate emissions when test data are not available. The EPA analysis of the ICR data has found that the emissions equation recommended by the commenter is not a good predictor of actual EGU emissions. The EPA also disagrees with commenters' concerns about the assumption that 12 percent of the Cr will be Cr(VI) for every coal-fired unit, which was specifically supported by the peer review on the approach for estimating cancer risks associated with Cr and Ni emissions. The EPA disagrees with the commenter's assertion that any impact of scrubbers will impact the case study analyses. In EPA's revised case study analysis, 6 facilities have risk greater than 1 in a million, and of these, four facilities have Cr as the risk driver (James River, Conesville, TVA Gallatin, and Dominion—Chesapeake Bay). For these facilities, none of the units contributing the bulk of the Cr emissions have scrubbers according to the data provided to EPA by those facilities, so scrubber impacts on Cr speciation is not relevant to EPA's conclusions based on the non-Hg case studies. In any case, the EPA disagrees with the commenter's conclusions about the impacts of scrubbers on Cr speciation and provides evidence that impacts of scrubbers on Cr speciation can have the opposite effect on Cr(VI) fractions, concluding that EPA's 12 percent assumption is somewhat conservative.

The EPA also disagrees that coal rank must be a factor in computing Cr emission factors for use in the case studies. The EPA's analysis has demonstrated that coal rank appears to play no role in non-Hg metals emissions. The EPA's newly revised emissions factor development procedures can isolate and compare subgroups based on control device type or coal rank; the ICR data were subjected to these tests and no statistical significance was found between coal rank groups.

Finally, the EPA agrees with one commenter's recommendations on revised stack parameters for the case studies and has included these revisions in the case study modeling for the final rule.

2. General Comments on Non-Hg Risk Case Study

Comment: One commenter stated that EPA's case study assessment reaffirms the need to regulate HAP emitted by both coal and oil-fired EGUs. The commenter noted that over 40 percent of the case studies conducted by EPA to quantify health hazards associated with the inhalation of non-Hg HAP indicated a cancer risk greater than or equal to the one in a million threshold level required to delist a source category under CAA section 112.

One commenter stated that EPA's case study assessment might be flawed by the use of "beta" tests versions of the AERMOD meteorological preprocessors (AERMINUTE and AERMET). The commenter obtained from EPA the meteorological data used for EPA's assessment of the Conesville facility and processed these data with EPA's current regulatory versions of these preprocessors, which differ from the beta version. According to the commenter, a comparison of the hourly wind speed and hourly wind direction data produced by the beta preprocessor and by current EPA preprocessors revealed numerous and often substantial disparities.

One commenter stated that EPA's finding that only three coal-fired facilities and one oil-fired facility out of roughly 440 coal-fired facilities and 97 oil-fired facilities in the U.S. indicated risk greater than one-in-a-million supports a finding that it is "appropriate" to regulate those four and not the other 537. Another commenter stated that EPA found only a "few" facilities that have estimated maximum cancer risks in excess of one in a million, and that this does not justify regulating all non-Hg HAP for all sources in this category.

One commenter stated that EPA's discussion in the preamble to the proposed rule misleads the reader into believing that non-Hg HAP emissions from EGUs are associated with serious human health effects. According to the commenter, the EPA's discussion of the effects associated with excessive exposure to an individual HAP would lead the reader to believe that those effects inevitably occur from EGU emissions because EGU emissions have trace amounts of non-Hg HAP.

One commenter stated that with the assumptions in the Utility Study, both in terms of conservative scientific estimates and overestimated amounts of oil burned by these units, the EPA concluded that the risks from oil-fired units would result in only one new cancer case every 5 years. The commenter does not believe that this level of risk warrants regulation under CAA section 112(n)(1)(A).

Several commenters stated that even if the additional studies EPA performed were accurate, they hardly demonstrate that it is necessary and appropriate to regulate coal-fired EGU HAP under CAA section 112 because three sites nationwide show risks greater than one in a million, with the highest at eight in a million.

One commenter stated that the highest cancer risk estimated for coal-fired EGUs is still within the acceptable range used by EPA in other programs and is also far less than the background exposure risks the average person experiences. The background risk of developing cancer in a lifetime is approximately one in three (0.33). According to EPA's own data, the predicted added cancer risk of exposure to HAP from U.S. EGUs would change the background risk from 0.33 to 0.330001. This level of change is so minimal that it could not be observed in any health effects study that might be conducted.

One commenter stated that EPA conducted a health risk assessment on a limited number of facilities and found a "few" facilities that have estimated maximum cancer risks in excess of one in a million. The commenter stated that, based on this limited health risk assessment, the EPA apparently decided that they were justified to regulate all non-Hg HAP for all sources in this category.

Several commenters stated that EPA's assumption implies that a person stays exactly at the center of a census tract for 70 years and that a unit will operate in exactly the same manner for 70 years is unrealistic. The commenters suggest that Tier 3 risk assessment is warranted

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or a lifetime exposure adjustment is needed.

One commenter asserts that because the alleged health benefits are derived from total exposure, the EPA should explain how its numerical emission limit units, which would not directly restrict total exposure if heat inputs increase, redress this health concern. In its preamble, the EPA simply notes that its emission limit units are consistent with, and allow for simple comparison to, other regulations.

One commenter questioned whether acid gas emissions limits for oil-fired units are "appropriate" or "necessary" because EPA's new technical analyses do not indicate a health concern from acid gas emissions from oil-fired units. According to the commenter, the EPA identifies Ni as the main HAP of concern from oil-fired units, even though cancer-related inhalation risks were well below the RfCs and EPA states that significant uncertainty remains as to whether those emissions present a health concern.

Response: The EPA agrees with the commenter that the non-Hg HAP risk assessment confirms the appropriate and necessary finding.

The EPA disagrees that EPA's case study assessment is flawed by the use of beta versions of AERMINUTE and AERMET. The EPA remodeled the case study facilities using the current versions of AERMINUTE (version 11059), AERMET (version 11059), and AERMOD (version 11103). Although there were differences in the number of calm and missing winds in the current AERMINUTE/AERMET output compared to the beta version, the resulting risks differed by less than two percent, on average. For Conesville, which had the largest difference in calms between the beta and current versions of AERMINUTE/AERMET, the risks differed by three percent. For the final rule, the case study facilities have been modeled with the current available versions of AERMINUTE, AERMET, and AERMOD.

The EPA disagrees with the commenter that having only a few case study facilities exceeding one in a million risk invalidates the "appropriate finding". The 16 facilities EPA selected as case studies for assessment may not represent the highest-emitting or highest-risk sources. Although case study facility selection criteria included high estimated cancer and non-cancer risks using the 2005 NEI data, high throughput, and minimal emission control, another necessary criterion was the availability of Information Collection Request (ICR) data for the EGUs at those facilities (or for similar EGUs at other facilities). Because the ICR data were collected for the purpose of developing the MACT standards, the ICR was targeted towards better performing sources for non-Hg metal HAP, acid gas HAP, and organic HAP, with a smaller set of random recipients. Therefore, facilities for which ICR data were available may not represent the highest-emitting sources. The EPA's assessment of the case study facilities for the proposed rule concluded that three coal-fired facilities and one oil-fired facility had estimated lifetime cancer risks greater than one in a million. For the final rule, revisions were made to the 16 case studies based on comments received, and the results indicate that 5 coal-fired facilities and 1 oil-fired facility had estimated lifetime cancer risks greater than 1 in a million. The EPA maintains that its finding that more than 30 percent of the case study facilities had a cancer risk greater than one in a million is sufficient to support the appropriate finding.

The EPA disagrees with the commenter's assertion that the health effects associated with exposures to non-Hg HAP from U.S. EGUs are mischaracterized in the preamble to the proposed rule. The discussion of the health effects of non-Hg HAP provided in the preamble includes general information on the potential health effects associated with a broad range of exposure concentrations (from low to high levels) of the various non-Hg HAP (some of which have been determined to be carcinogenic to humans) based on peer reviewed scientific information extracted from priority sources such as IRIS, Cal EPA and ATSDR health effects assessments.

The EPA disagrees with the commenter's characterization of the Utility Study. The Utility Study represented the highest-quality factual record of information available at the time regarding EGU emissions and risks. Further, the EPA's revised risk assessments of 16 case studies, performed with more recent data and refined scientific methods, indicate that there are six U.S. EGU facilities that pose estimated inhalation cancer risks greater than 1 in a million. The EPA maintains that the findings of the case studies are one element that independently supports our determination that it remains appropriate and necessary to regulate EGUs under CAA section 112.

The EPA does not agree with the commenter who suggested that EPA should interpret the results of the non-Hg HAP risk analysis in the context of background cancer risk. As explained in the preamble to the proposed rule, the EPA reasonably looked to the cancer risk threshold established under CAA section 112(c)(9)(B)(1) for delisting a source category as an indicator of the level of cancer risk that was appropriate to regulate under CAA section 112. The commenters comparison of the cancer risk from EGUs as compared with the risk of contracting cancer from unknown sources is not the standard Congress established for evaluating HAP emission risk and the commenter has provided no support for its contention that the Agency should evaluate risk in that manner. The EPA maintains that the analysis was reasonable.

The EPA does not agree with the commenter's implication that EPA must make a facility-specific finding for each HAP for each source and then only regulate individual EGU facilities for the individual HAP that identified as causing an identified hazard to public health or the environment. That approach is not required under CAA section 112(n)(1) or anywhere under CAA section 112, and it would be virtually impossible to undertake such an effort. For these reasons, the EPA does not agree with the commenter and maintains that the appropriate and necessary finding is reasonably supported by the record and consistent with the statute for all the reasons set forth in the preamble to the proposed rule and this final action.

The EPA disagrees that an exposure adjustment is needed to account for conditions changing over 70 years because it runs counter to the long-standing approach that EPA has taken to estimate the maximum individual risk, or MIR. The MIR is defined by EPA's Benzene NESHAP regulation of 1989 [278] and codified by CAA section 112(f) as the lifetime risk for a person located at the site of maximum exposure 24 hours a day, 365 days a year for 70 years (*e.g.*, census block centroids). The MIR is the metric associated with the determination of whether or not a source category may be delisted from regulatory consideration under CAA section 112(c)(9). The MIR is the risk metric used to characterize the inhalation cancer risks associated with the case study facilities. The EPA used the annual average ambient air concentration of each HAP at each census block centroid as a surrogate for the lifetime inhalation exposure concentration of all the people who reside in the census block. The EPA has used this approach to estimate MIR values in all of its risk assessments to

[278] 54 FR 38044.

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support risk-based rulemakings under CAA section 112 to date.

The EPA disagrees with the commenter's assertion that the numerical emission limits being promulgated in today's final rule must be justified on their ability to redress the health concerns that were identified as the basis for regulating EGUs. The emission limits in today's rule are technology-based, as prescribed under CAA section 112, and do not need to be justified based on their ability to protect public health. Regarding potential health concerns, the EPA has up to 8 years after the promulgation of the technology-based emission limits for EGUs to determine whether the regulations protect public health with an ample margin of safety. If the regulations do not, the CAA directs EPA to promulgate additional more stringent standards (within the prescribed 8 years) to achieve the appropriate level of public health protection.

Furthermore, the EPA reasonably concluded that it was appropriate and necessary to regulate oil-fired EGUs in 2000, and EPA confirmed that conclusion was proper with the analysis set forth in the preamble to the proposed rule. Certain commenters question the determination based on their views of how the Agency can and should exercise its discretion. The EPA disagrees with these commenters and stands by the determination for the reasons set forth in the preamble to the proposed rule. The EPA also stands by the determination that the maximum cancer risks posed by emissions of oil-fired EGUs are greater than one in a million, due primarily to emissions of Ni compounds. Based on our analysis, we are unable to delist oil-fired EGUs.

3. Ni Risk

Comment: Several commenters stated that the assumptions regarding the speciation and carcinogenic potential of Ni compounds used in EPA's inhalation risk assessment of the case study facilities are overly conservative and likely to overstate the risks. With respect to Ni speciation, the commenters stated that there are substantial uncertainties regarding the species of Ni being emitted and the risk of such emissions, and that EPA has made ultraconservative assumptions aimed at overestimating the risk. The commenters stated that assigning the same carcinogenic potency of Ni subsulfide to other forms of Ni is overly conservative and inconsistent with the best available evidence.

Response: The EPA disagrees with the commenters' assertion that it is impossible to give an accurate assessment of the risks to human health from Ni emissions from EGUs, and maintains that its assessment of the potential inhalation risks from EGU emissions of Ni compounds is scientifically valid, reasonable, and based on the best-available current scientific understanding. To that end, in July 2011, the EPA completed an external peer review (using three independent expert reviewers) of the methods used to evaluate the risks from Ni and Cr compounds emitted by EGUs.[279] There were two charge questions relating to Ni in that review. First, do EPA's judgments related to speciated Ni emissions adequately take into account available speciation data, including recent industry spectrometry studies? Second, based on the speciation information available and what is known about the health effects of Ni compounds, and taking into account the existing URE values (*i.e.,* values derived by the Integrated Risk Information System,[280] California Department of Health Services,[281] and the Texas Commission on Environmental Quality[282]), which of the following approaches to derive unit risk estimates would result in a more accurate and defensible characterization of risks from exposure to Ni compounds?

1. To continue using the same approach as that developed for use in the 2000 NATA, which consists of using the IRIS URE for nickel subsulfide and assuming that nickel subsulfide constitutes 65 percent of the mass emissions of all Ni compounds.

2. To consider a more health-protective approach, based on the consistent views of the most authoritative scientific bodies (*i.e.,* NTP in their 12th ROC, IARC, and other international agencies) that consider Ni compounds to be carcinogenic as a group.

3. To make the same assumptions as in option 2, but considering alternative UREs derived by the CDHS or TCEQ.

In responding to these peer review questions, two of the reviewers agreed with the views of the most authoritative scientific bodies, which consider Ni compounds carcinogenic as a group. These reviewers, therefore, did not focus on the availability of Ni speciation profile data. The third reviewer recommended that EPA review several manuscripts on Ni speciation profiles showing that sulfidic Ni compounds (which the reviewer considered as the most potent carcinogens) are present at low levels in emissions from EGUs.

Nickel and Ni compounds have been classified as human carcinogens by national and international scientific bodies including the IARC,[283] the World Health Organization,[284] and the European Union's Scientific Committee on Health and Environmental Risks.[285] In their *12th Report of the Carcinogens,* the NTP has classified Ni compounds as known to be human carcinogens based on sufficient evidence of carcinogenicity from studies in humans showing associations between exposure to Ni compounds and cancer, and supporting animal and mechanistic data. More specifically, this classification is based on consistent findings of increased risk of cancer in exposed workers, and supporting evidence from experimental animals that shows that exposure to an assortment of Ni compounds by multiple routes causes malignant tumors at various organ sites and in multiple species. The *12th Report of the Carcinogens* states that the "combined results of epidemiological studies, mechanistic studies, and carcinogenesis studies in rodents support the concept that Ni compounds generate Ni ions in target cells at sites critical for carcinogenesis, thus allowing consideration and evaluation of these compounds as a single group".[286] Although the precise Ni compound (or compounds) responsible for the carcinogenic effects in humans is not always clear, studies indicate that Ni sulfate and the combinations of Ni sulfides and oxides encountered in the Ni refining industries cause cancer in humans. There have been different views on whether or not Ni compounds, as a group, should be considered as carcinogenic to humans. Some authors

[279] U.S. EPA, 2011c.

[280] *U.S.* EPA, 1991.

[281] California Department of Health Services (CDHS) 1991. Health Risk Assessment for Nickel. Air Toxicology and Epidemiology Section, Berkeley, CA. Available online at *http://oehha.ca.gov/air/toxic_contaminants/html/Nickel.htm.*

[282] Texas Commission on Environmental Quality (TCEQ), 2011. Development Support Document for nickel and inorganic nickel compounds. Available online at *http://www.tceq.state.tx.us/assets/public/implementation/tox/dsd/final/june11/nickel_&_compounds.pdf.*

[283] International Agency for Research on Cancer (IARC), 1990. IARC monographs on the evaluation of carcinogenic risks to humans. *Chromium, nickel and welding.* Vol. 49. Lyons, France: International Agency for Research on Cancer, World Health Organization Vol. 49:256.

[284] International Labour Organization/United Nations Environment Programme, World Health Organization (WHO), 1991. Nickel. In Environmental Health Criteria No 108 Geneva.

[285] European Commission, Scientific Committee on Health and Environmental Risks (SCHER), 2006. Opinion on: Reports on Nickel, Human Health part. SCHER, 11th plenary meeting of 04 May 2006 *http://ec.europa.eu/health/ph_risk/committees/04_scher/docs/scher_o_034.pdf.*

[286] NTP, 2011.

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believe that water soluble Ni, such as Ni sulfate, should not be considered a human carcinogen, based primarily on a negative Ni sulfate 2-year NTP rodent bioassay (which is different than the positive 2-year NTP bioassay for Ni subsulfide).[287] [288] [289] Although these authors agree that the epidemiological data clearly supports an association between Ni and increased cancer risk, they sustain that the data are weakest regarding water soluble Ni. A recent review [290] highlights the robustness and consistency of the epidemiological evidence across several decades showing associations between exposure to Ni and Ni compounds (including Ni sulfate) and cancer.

Based on the views of the major scientific bodies mentioned above, and those of expert peer reviewers that commented on EPA's approaches to risk characterization of Ni compounds, the EPA considers all Ni compounds to be carcinogenic as a group and does not consider Ni speciation or Ni solubility to be strong determinants of Ni carcinogenicity. With regards to non-cancer effects, comparative quantitative analysis across Ni compounds indicates that Ni sulfate is as toxic or more toxic than Ni subsulfide or Ni oxide.[291] [292]

Regarding the second charge question, two of the reviewers suggested using the URE derived by TCEQ for all Ni compounds as a group, rather than the one derived by IRIS specifically for Ni subsulfide. The third reviewer did not comment on alternative approaches. The EPA decided to continue using 100 percent of the current IRIS URE for Ni subsulfide because IRIS values are at the top of the hierarchy with respect to the dose response information used in EPA's risk characterizations, and because of the concerns about the potential carcinogenicity of all forms of Ni raised by the major national and international scientific bodies. Nevertheless, taking into account that there are potential differences in toxicity and/or carcinogenic potential across the different Ni compounds, and given that there have been two URE values derived for exposure to mixtures of Ni compounds that are 2–3 fold lower than the IRIS URE for Ni subsulfide, the EPA also considers it reasonable to use a value that is 50 percent of the IRIS URE for Ni subsulfide for providing an estimate of the lower end of a plausible range of cancer potency values for different mixtures of Ni compounds.

4. Cr Risk

Comment: One commenter stated there are several problems with EPA's analysis related to the fact that Cr emissions were evaluated as being entirely Cr(VI). The commenter stated that not all of the emitted Cr will remain in the hexavalent form by the time it reaches the target population, and that some may be converted to the much less toxic (and noncarcinogenic) trivalent species. The commenter also stated that the concentration levels considered in the case study assessment are far below occupational levels. The commenter concluded that EPA's cancer estimates should, therefore, be looked on with some skepticism. Another commenter stated that EPA's estimate of 12 percent Cr(VI) from coal-fired EGUs is unsupported, and that EPA failed to recognize that Cr(VI) is highly water-soluble and is easily reduced to Cr(III) in the presence of SO_2 in a low pH environment. The resulting Cr(III) would be expected to precipitate out in a FGD. The commenter stated that the actual amount of Cr(VI) that would be present in the emissions from an EGU with a wet scrubber is likely to be far lower than the 12 percent estimate made by EPA.

Several commenters questioned the validity of the chronic inhalation study by EPA because of (1) the use of surrogate speciated Cr emissions data instead of actual emissions data, (2) the assumption that units were run 100 percent of the time which is impossible, (3) dispersion modeling was used that is biased towards over predicting downwind impacts, and (4) estimated ambient concentrations were utilized as substitutes for real exposure concentrations for all people within a census block.

Response: The EPA disagrees with the commenters' assertion that all Cr was considered to be hexavalent. As discussed in "Methods to Develop Inhalation Cancer Risk Estimates for Chromium and Nickel Compounds," [293] existing test data for utility and industrial boilers indicate that Cr(VI) is, on average, 12 percent of total Cr from coal-fired boilers. This document underwent peer review by three external reviewers, and all three reviewers considered EPA's use of the values to be reasonable given the limited data available for Cr speciation profiling. The EPRI inhalation study for coal-fired boilers also used the 12 percent value.

The EPA also disagrees that units were assumed to operate 100 percent of the time. The dispersion modeling performed for the case study facilities used hourly heat input as a temporalization factor for estimating hourly emissions, and in some cases hourly heat inputs (and emissions) were zero or very low. The commenter provided no data or information to support their claim that the dispersion modeling EPA used is biased towards overestimating downwind impacts.

The EPA disagrees with the commenters' assertion that "real exposure concentrations for all people within a census block" must be considered because it runs counter to the long-standing approach that EPA has taken to estimate the maximum individual risk, or MIR. The MIR is defined by EPA's Benzene NESHAP regulation of 1989 [294] and codified by CAA section 112(f) as the lifetime risk for a person located at the site of maximum exposure 24 hours a day, 365 days a year for 70 years (*e.g.*, census block centroids). The MIR is the metric associated with the determination of whether or not a source category may be delisted from regulatory consideration under CAA section 112(c)(9). The MIR is the risk metric used to characterize the inhalation cancer risks associated with the case study facilities. The EPA used the annual average ambient air concentration of each HAP at each census block centroid as a surrogate for the lifetime inhalation exposure concentration of all the people who reside in the census block. The EPA has used this approach to estimate MIR values in all of its risk assessments to support risk-based rulemakings under CAA section 112 to date.

5. Acid Gas Risk

Comment: One commenter stated that acid gas emissions from oil-fired EGUs are not of the magnitude that triggered EPA's decision to regulate EGUs in general, raising the question of whether reduction (or even total elimination) of acid gas emissions from oil-fired EGUs could have any significant effect on EPA's goals of reducing non-cancer

[287] Oller A. Respiratory carcinogenicity assessment of soluble nickel compounds. Environ Health Perspect. 2002, 110:841–844.

[288] Heller JG, Thornhill PG, Conard BR. New views on the hypothesis of respiratory cancer risk from soluble nickel exposure; and reconsideration of this risk's historical sources in nickel refineries. J Occup Med Toxicol. 2009, 4:23.

[289] Goodman JE, Prueitt RL, Thakali S, and Oller AR. The nickel iron bioavailability model of the carcinogenic potential of nickel-containing substances in the lung. Crit Rev Toxicol. 2011, 41:142–174.

[290] Grimsrud TK and Andersen A. Evidence of carcinogenicity in humans of water-soluble nickel salts. J Occup Med Toxicol. 2010. 5:1–7. Available online at *http://www.ossup-med.com/content/5/1/7.*

[291] Haber LT, Allen BC, Kimmel CA. Non-Cancer Risk Assessment for Nickel Compounds: Issues Associated with Dose-Response Modeling of Inhalation and Oral Exposures. Toxicol Sci. 1998. 43:213–229.

[292] NTP, 1996.

[293] U.S. EPA, 2011c.

[294] 54 FR 3804.

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health risk or acidification of sensitive ecosystems in the U.S.

Several commenters stated that acid gas concentrations estimated in the case study facility assessment and the Utility Study do not exceed human health thresholds of concern. Two commenters stated that HCl emissions are negligible compared to other primary emissions (such as SO_2) that can lead to potential acidification of ecosystems.

Response: We do not agree with commenter's implication that Congress intended EPA to regulate only those HAP emissions from U.S. EGUs for which an appropriate and necessary finding is made, and commenter has cited no provision of the statute that states a contrary position. The EPA concluded that we must find it "appropriate" to regulate EGUs under CAA section 112 if we determine that a single HAP emitted from EGUs poses a hazard to public health or the environment. If we also find that regulation is necessary, the Agency is authorized to list EGUs pursuant to CAA section 112(c) because listing is the logical first step in regulating source categories that satisfy the statutory criteria for listing under the statutory framework of CAA section 112. *See New Jersey,* 517 F.3d at 582 (stating that "[s]ection 112(n)(1) governs how the Administrator decides whether to list EGUs * * *"). As we noted in the preamble to the proposed rule, D.C. Circuit precedent requires the Agency to regulate all HAP from major sources of HAP emissions once a source category is added to the list of categories under CAA section 112(c). *National Lime Ass'n* v. *EPA,* 233 F.3d 625, 633 (D.C. Cir. 2000). 76 FR 24989. The EPA discusses in the preamble to the proposed rule and this final action its concerns with HCl and other acid gas HAP emissions from EGUs and the Agency's approach for establishing section 112(d) standards for acid gas HAP.

6. EPRI Risk Analysis

Comment: Two commenters stated that a comprehensive tiered inhalation risk assessment (the EPRI study) using EPA-prescribed methods with improved emission factors, fuel data, and confirmed stack parameters did not identify significant health risks (cancer or non-cancer) among U.S. coal-fired power plants (as they existed in 2007). The commenters noted that these results contrast with those presented by EPA for its non-Hg case studies on 16 (15 coal-fired) power plants. The commenters stated that several issues appear to underlie these differences, indicating the need for EPA to reevaluate its assessment and to undertake more refined (Tier 3) risk assessment for any facility of concern. Several commenters stated that for non-Hg HAP EPA produced one study on chronic inhalation risk assessment that identified three sites with cancer risks greater that one in a million for Cr(VI), which was authored by EPA staff and not peer reviewed. One commenter stated that EPA study is based on misinformation and overestimates assumptions, and that EPA has no data demonstrating health impacts from EGU emissions of non-Hg HAP, or the benefit from reducing such emissions. Two commenters stated that no benefits will be derived from the non-Hg HAP emission reductions associated with the proposed rule because no non-Hg HAP health risks were proven, and that no showing was made that EGU non-Hg HAP emission levels reach levels associated with adverse health effects. Another commenter stated that EPA must complete a comparable and separate national-scale risk assessment for non-Hg metals in order to determine appropriateness of proposing emissions standards for non-Hg metals.

Response: The commenters are incorrect in the assertion that EPA's case studies were performed with less rigor than the EPRI analysis. The EPRI analysis used a tiered approach to risk assessment, beginning with Tier 1 using EPA's SCREEN3 dispersion model on all 470 coal-fired power plants in the U.S., and following with Tier 2 with EPA's Human Exposure Model (which uses the AERMOD dispersion model) for plants with higher risks from the Tier 1 modeling. Although tiered risk assessment is an appropriate approach, the Tier 2 modeling could have been more refined. For example, more meteorological data could have been used and building downwash could have been considered. The EPRI analysis ostensibly concluded that the Tier 2 modeling with HEM was conservative, and that because the modeled risks did not exceed certain thresholds, no further refinement was necessary. However, such refinements could result in higher modeled risks than those from the commenter's Tier 2 modeling.

The EPA's dispersion modeling of the case study facilities was actually performed with a greater degree of refinement than the EPRI analysis, and was consistent with EPA's *Guideline on Air Quality Models.*[295]

In contrast to the approach used in the EPRI analysis, the EPA used:

(1) 5 years of recent meteorological data from the weather station nearest to each facility, rather than one year of meteorological data. This is more representative of long-term (*i.e.,* lifetime) exposures and risks.

(2) Temporally-varying emissions based on continuous emissions monitoring data, rather than assuming a constant emission rate for each facility throughout the entire simulation.

(3) Building downwash, where appropriate.

(4) The latest version of AERMOD [version 11103].

The EPA's assessment of the case study facilities for the proposed rule concluded that three coal-fired facilities and one oil-fired facility had estimated lifetime cancer risks greater than one in a million. For the final rule, revisions were made to the case studies based on comments received, and the results indicate that five coal-fired facilities and one oil-fired facility had estimated lifetime cancer risks greater than one in a million.

Regarding peer review, the risk assessment methodology used by EPA for the case studies was consistent with the method that EPA uses for assessments performed for Risk and Technology Review rulemakings, which underwent peer review by the Science Advisory Board in 2009.[296] The SAB issued its peer review report in May 2010. The report generally endorsed the risk assessment methodologies used in the program. In addition, in July 2011, the EPA completed a letter peer review of the methods used to develop inhalation cancer risk estimates for Cr and Ni compounds.

f. Ecosystem Impacts From HAP

Comment: Two commenters assert that EPA is not justified in regulating acid gases based on concern about the potential that acid gases contribute to ecosystem acidification rather than concerns about hazards to public health. The commenters further claim that HCl's contribution to ecosystem acidification is de minimis. The commenters point out that EPA acknowledges uncertainty in quantification of acidification and EPA relies on recently published research[297] that is irrelevant to the question since it is based on research conducted in the peat bog ecosystem in the United Kingdom. Another commenter calls attention to several new studies published in a special issue of the

[295] Appendix W to 40 CFR Part 51.

[296] U.S. EPA–SAB, 2010.

[297] Evans, Chris D., Don T. Monteith, David Fowler, J. Neil Cape, and Susan Brayshaw. 2011. "Hydrochloric Acid: An Overlooked Driver of Environmental Change." *Environmental Science & Technology* 45 (5), 1887–1894.

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journal *Ecotoxicology* devoted to the effects of MeHg on wildlife.

Response: Although EPA agrees that quantification of acidification effects has remaining uncertainty, the science and methodology has progressed in recent years. Based on recent peer reviewed research including Evans et al.,[298] acid gases can significantly contribute to acidification. The EPA published a comprehensive risk assessment of acidification effects of nitrogen and sulfur deposition [299] and a policy assessment.[300] Given the extent and importance of the sensitive ecosystems evaluated in the review of nitrogen and sulfur deposition any substance that contributes to further acidification must be considered to be affecting the public welfare. The EPA disagrees that the peer reviewed study mentioned by commenter by Evans *et al.,* (2011) is not relevant to U.S. ecosystems. The paper presents evidence that show (1) that HCl is highly mobile in the environment, transferring acidity easily through soils and water, (2) that HCl can transport longer distances than previously thought (given its presence in remote ecosystems, and (3) that it can be a larger driver of acidification than previously thought. The fact that this study took place in the U.K. is itself irrelevant. The chemical interactions of HCl in water are the same the world over and sensitive ecosystems exist in the U.S. as well as in Europe as illustrated in the ecological risk assessment [301] for NO_X and SO_X. Furthermore, the commenter is factually incorrect that EPA is justifying that it is appropriate and necessary to regulate HAP emissions from EGUs based on this one study. The EPA agrees with the commenter that Hg exposure in wildlife is responsible for various adverse health effects in many species across the U.S. and recognizes that research is ongoing in this area. As discussed in the preamble to the proposed rule, the EPA agrees that there are potential environmental risks from exposures of ecosystems through Hg and non-Hg HAP deposition. The EPA cited relevant articles from the special edition of *Ecotoxicology* [302] mentioned by the commenter in the ecosystem effects section on Chapter 5 of the RIA for this rule, which is available in the docket.

G. EPA Affirms the Finding That It Is Appropriate and Necessary to Regulate EGUs To Address Public Health and Environmental Hazards Associated With Emissions of Hg and Non-Hg HAP From EGUs

In response to peer reviews of both the Hg and non-Hg HAP risk analyses, and taking into account public comments, the EPA conducted revised analyses of the risks associated with emissions of Hg and non-Hg HAP from U.S. EGUs. These revised analyses demonstrated that the risk results reported in the preamble to the proposed rule are robust to revisions in response to the peer reviews and public comments.

Specifically, the revised Hg Risk TSD shows that up to 29 percent of modeled watersheds have populations potentially at-risk from exposure to Hg from U.S. EGUs.[303] This 29 percent of watersheds with populations potentially at-risk includes up to 10 percent of modeled watersheds where deposition from U.S. EGUs alone leads to potential exposures that exceed the MeHg RfD, and up to 24 percent of modeled watersheds where total potential exposures to MeHg exceed the RfD and U.S. EGUs contribute at least 5 percent to Hg deposition. Each of these results independently supports our conclusion that U.S. EGUs pose hazards to public health.

In the preamble to the proposed rule and in the 2000 finding, the EPA explained at length the serious nature of the health effects associated with Hg exposures, and the persistent nature of Hg in the environment. Congress specifically recognized the significant impacts of persistent bioaccumulative pollutants, like Hg, when it enacted section 112(c)(6), which requires the EPA to subject source categories listed pursuant to that section to MACT standards. Congress also required certain studies be conducted under CAA section 112(n) regarding the health effects of Hg. The EPA interprets CAA section 112(n)(1), with regard to Hg, as intended to protect the public, including sensitive populations, against exposures to Hg from EGUs that would exceed the level determined by the EPA to be without appreciable risk, *e.g.,* exposures that are above the RfD for methylmercury (MeHg), or would contribute additional risk in areas where Hg exposures exceed the RfD due to contributions from all sources of Hg. Our recent technical analyses show that 98 percent of the watersheds for which we had fish tissue data have total Hg deposition such that potential exposures exceed the MeHg RfD, above which there is an increased risk of adverse effects on human health. In these watersheds, any reductions in exposures to Hg will reduce risk, and thus the incremental contribution to Hg exposure from any individual source or group of sources, such as EGUs, may reasonably be anticipated to cause additional risk.

As we have explained, in calculating the estimates described above, the EPA has used peer-reviewed methods, and focused on populations likely to be at higher risk of exposure to Hg from U.S. EGUs, *e.g.,* female subsistence fishing populations consuming at the 99th percentile fish consumption rate. The EPA did not, however, use the most conservative assumptions that would lead to upper bound risk estimates. As discussed above and in the revised Hg Risk TSD, we did not use the highest fish tissue cooking loss adjustment factor that was reported in the literature, which, had we done so, would have increased the estimates of Hg exposure substantially. Thus, we believe our analysis could understate risk to the most exposed individual, noting that we have focused on the 99th percentile consumption rate in our estimates.

Further, we were able to assess potential Hg exposures in only a small subset of generally representative watersheds in the U.S. because our analysis was necessarily premised on those water bodies for which we had fish tissue Hg samples. Specifically, we analyzed 3,141 of the approximately 88,000 watersheds in the United States. This limited set of watersheds excludes several of the watersheds with the highest U.S. EGU attributable deposition, and may also not have included watersheds with the highest sensitivity to Hg deposition, *e.g.,* the highest methylation rates (see above). Nevertheless, our analysis of the subset of watersheds we examined demonstrates that almost one third of the watersheds are estimated to have Hg deposition attributable to U.S. EGUs that contributes to potential exposures above the MeHg RfD. The SAB

[298] Id.

[299] U.S. Environmental Protection Agency (U.S. EPA). 2009. *Risk and Exposure Assessment for Review of the Secondary National Ambient Air Quality Standards for Oxides of Nitrogen and Oxides of Sulfur (Final).* EPA–452/R–09–008a. Office of Air Quality Planning and Standards, Research Triangle Park, NC. September. Available on the Internet at *http://www.epa.gov/ttn/naaqs/standards/no2so2sec/data/NOxSOxREASep2009MainContent.pdf.*

[300] U.S. Environmental Protection Agency (U.S. EPA). 2011d. *Policy Assessment for the Review of the Secondary National Ambient Air Quality Standards for Oxides of Nitrogen and Oxides of Sulfur.* EPA–452/R–11–005a. Office of Air Quality Planning and Standards, Research Triangle Park, NC. February. Available on the Internet at *http://www.epa.gov/ttnnaaqs/standards/no2so2sec/data/20110204pamain.pdf.*

[301] U.S. EPA, 2009.

[302] *Ecotoxicology* 17:83–91, 2008.

[303] This corresponds to 28 percent of modeled watersheds with populations potentially at-risk in the analysis reported in the preamble to the proposed rule.

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confirmed that the subset of watersheds we examined is sufficient.

Considering these points and the information on Hg in the record, the EPA believes that 10 percent of watersheds with populations at risk due to U.S. EGU emissions alone is unacceptable, as is 24 percent of watersheds with populations at risk due to U.S. EGU contributions in conjunction with total deposition from other sources. Taking into account the percentage of watersheds at risk, and the potential for even higher percentages to be at risk using more conservative risk assumptions and a more complete coverage of high U.S. EGU Hg deposition watersheds, the EPA concludes that Hg emissions from U.S. EGUs pose a hazard to public health.

Given these findings, and considering that (1) the revised risk analysis showed the percent of modeled watersheds with populations potentially at-risk increased from 28 to 29 percent, and (2) the revised analysis includes 36 percent more watersheds, which significantly expands the coverage in several states, we conclude that the finding that emissions of Hg from U.S. EGUs pose a hazard to public health is confirmed by the national-scale revised Hg Risk TSD. As a result, we conclude that it remains appropriate to regulate Hg emissions from U.S. EGUs because those Hg emissions pose a hazard to public health.

With regards to the revised non-Hg inhalation case studies, the highest estimated individual lifetime cancer risk for the one case study facility (out of 16) with oil-fired EGUs is estimated to be 20 in a million, driven by Ni emissions. For the facilities with coal-fired EGUs, there were five (out of 16) with maximum individual cancer risks greater than one in a million (the highest was five in a million), four of which were driven by emissions of Cr(VI), and one of which was driven by emissions of Ni. Therefore, a total of six facilities exceed the criterion for EGUs to be regulated under CAA section 112. There were also two facilities with coal-fired EGUs with maximum individual cancer risks at one in a million. In the preamble to the proposed rule, we reported that the maximum individual lifetime cancer risk for the one facility with oil-fired EGUs was estimated to be 10 in a million, and that there were 3 coal-fired EGU facilities with maximum individual cancer risks greater than 1 in a million (the highest was 8 in a million), and 1 coal-fired EGU facility with maximum individual cancer risks equal to 1 in a million. Given that (1) the lifetime cancer risk for the oil-fired EGU facility has increased from 10 to 20 in a million, (2) the number of coal-fired EGU facilities with cancer risks greater than 1 in a million has increased from 3 to 5, and (3) the highest risk coal-fired facility still has cancer risks of 5 in a million, which is above the 1 in a million benchmark, we conclude that the finding that emissions of non-Hg HAP from U.S. EGUs pose a hazard to public health is confirmed by the revised non-Hg risk inhalation case studies.

Moreover, some HAP emissions from U.S. EGUs contribute to adverse ecosystem effects. While we did not do new analyses on these topics, we reiterate that (1) Hg emissions from U.S. EGUs pose a hazard to the environment, contributing to adverse impacts on fish-eating birds and mammals, (2) Hg is a persistent bioaccumulative environmental contaminant, and as a result, failing to control Hg emissions from U.S. EGU sources will result in long-term environmental loadings of Hg, above and beyond those loadings caused by immediate deposition of Hg within the U.S.; controlling Hg emissions from U.S. EGUs helps to reduce the potential for environmental hazard from Hg now and in the future, and (4) it is appropriate to regulate those HAP which are not known to cause cancer but are known to contribute to chronic non-cancer toxicity and environmental degradation, such as the acid gases. In addition, we have identified effective controls available to reduce Hg and non-Hg HAP emissions.

In summary, we confirm the findings that Hg and non-Hg HAP emissions from U.S. EGUs each pose hazards to public health and that it remains appropriate to regulate U.S. EGUs under CAA section 112 for those reasons. We also conclude that it remains appropriate to regulate EGUs under CAA section 112 because of the magnitude of Hg and non-Hg emissions and the environmental effects of Hg and some non-Hg emissions, each of which standing alone, supports the appropriate finding. The availability of controls to reduce HAP emissions from EGUs only further supports the appropriate finding.

Our revised analyses still show that in 2016 after implementation of other provisions of the CAA, HAP emissions from U.S. EGUs are reasonably anticipated to pose hazards to public health; therefore, it is necessary to regulate EGUs under CAA section 112. Moreover, HAP emissions from U.S. EGUs are expected to continue to contribute to adverse ecosystem effects. In addition, based on evaluation of the regulations required by the CAA, including the recent CSAPR, it is necessary to regulate U.S. EGUs under CAA section 112 because the only way to ensure permanent reductions in HAP emissions from U.S. EGUs and the associated risks to public health and the environment is through standards set under CAA section 112. While CSAPR is projected to achieve some Hg reductions due to co-control of Hg provided by controls put in place to achieve required reductions in SO_2 emissions, the results of the revised Hg Risk TSD indicate that an unacceptable percentage of modeled watersheds have populations potentially at-risk from U.S. EGU-attributable Hg deposition would remain after implementation of CSAPR. While we modeled slightly higher Hg emissions from U.S. EGUs (*i.e.*, 29 tons of Hg) in our risk analysis compared to the most recent estimate of 27 tons, we do not believe this 2 ton difference would substantially change our finding that Hg emissions from U.S. EGUs pose a hazard to public health or the Hg risks reported in the preamble to the proposed rule, as this represents less than a 10 percent reduction in Hg emissions. In addition, the actual reductions in Hg that will occur due to application of controls to meet the SO_2 emissions requirements of CSAPR may differ from those projected to occur, due to differences in the technologies that individual EGU sources choose to install. The only way to ensure reductions in Hg, including those modeled as resulting from the CSAPR, is to directly regulate Hg emissions under CAA section 112.

In summary, we confirm the findings that it is necessary to regulate HAP emissions from U.S. EGUs because (1) the national-scale Hg Risk TSD shows that the hazards to public health posed by Hg emissions from U.S. EGUs will not be addressed through imposition of the CAA, (2) we cannot be certain that the identified cancer risks attributable to U.S. EGUs will be addressed through imposition of the requirements of the CAA, (3) the environmental hazards posed by acidification will not be fully addressed through imposition of the CAA, (4) regulation under CAA section 112 is the only way to ensure that all HAP emissions reductions that have been achieved since 2005 remain permanent, and (5) direct control of Hg emissions affecting U.S. deposition is only possible through regulation of U.S. emissions as we are unable to control global emissions directly. All of these findings independently support a finding that it is necessary to regulate U.S. EGUs under CAA section 112.

Based on these findings, the Agency affirms its finding that it remains appropriate and necessary to regulate

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coal- and oil-fired EGUs under CAA section 112, and maintains that the inclusion of coal- and oil-fired EGUs on the CAA section 112(c) list of source categories regulated under CAA section 112 remains valid.

IV. Denial of Delisting Petition

During the comment period on the proposed rule, UARG submitted a petition pursuant to CAA section 112(c)(9), asking the Agency to delete a portion of the EGU source category from the list of source categories to be regulated under CAA section 112. Specifically, UARG asks that EPA delist coal-fired EGUs from the CAA section 112(c) source category list. A copy of UARG's petition has been placed in the docket for today's rulemaking, along with the analysis conducted by EPRI that UARG uses to support its petition (hereinafter referred to as UARG's analysis). In support of its petition, UARG asserts that: (1) No coal-fired EGU or group of coal-fired EGUs will emit HAP in amounts that will cause a lifetime cancer risk greater than one in one million; and (2) no coal-fired EGU or group of coal-fired EGUs will emit non-carcinogenic HAP in amounts that will exceed a level which is adequate to protect public health with an ample margin of safety or cause adverse environmental effects. We disagree with UARG's assertions and for the reasons set forth below are denying UARG's petition to delist coal-fired EGUs from the section 112(c) source category list.

A. Requirements of CAA Section 112(c)(9)

CAA section 112(c)(9)(B) provides that "[t]he Administrator may delete any source category" from the section 112(c) source category list if the Agency determines that: (i) For HAP that may cause cancer in humans, "no source in the category (or group of sources in the case of area sources) emits such hazardous air pollutants in quantities which may cause a lifetime risk of cancer greater than one in one million to the individual in the population who is most exposed to emissions of such pollutants from the source (or group of sources in the case of area sources)"; and (ii) for HAP that may result in human health effects other than cancer or adverse environmental effects, "a determination that emissions from no source in the category or subcategory concerned (or group of sources in the case of area sources) exceed a level which is adequate to protect public health with an ample margin of safety and no adverse environmental effect will result from emissions from any source."

The EPA has the discretion to delete a source category under CAA section 112(c)(9)(B), but only if EPA concludes that the relevant requirements of CAA section 112(c)(9)(B) have been met. HAP emissions from EGUs present both cancer risks, which implicate the requirements of CAA section 112(c)(9)(B)(i), and non-cancer human health effects or adverse environmental effects, which implicate the requirements of CAA section 112(c)(9)(B)(ii). As such, UARG bears the burden of demonstrating that the requirements of *both* clauses are met.

B. Rationale for Denying UARG's Delisting Petition

The EPA is denying UARG's petition to delist EGUs from the CAA section 112(c) source category list. UARG improperly seeks to delist a portion of a CAA section 112(c) listed source category that emits carcinogens, which is contrary to the plain language of CAA section 112(c)(9). Even setting aside this fundamental defect, UARG has failed to meet the requirements of CAA section 112(c)(9)(B).

1. UARG's Attempt to Delist a Portion of a Listed Source Category Conflicts With D.C. Circuit Precedent

In December 2000, the EPA listed coal- and oil-fired EGUs as a single source category. UARG asks the Agency to delist a portion of that listed source category: Coal-fired EGUs. UARG's request conflicts, however, with D.C. Circuit precedent, which provides that for categories, like EGUs, that pose cancer risks, the EPA may not delist a portion of a source category. *NRDC* v. *U.S. EPA*, 489 F.3d 1364 (D.C. Cir. 2007). Specifically, in *NRDC*, the D.C. Circuit held that the Agency's attempt to delist a "low-risk" subcategory was "contrary to the plain language of the statute," and that the statute only authorized the agency to remove source categories pursuant to section 112(c)(9). *Id. at 1373* ("Because EPA's interpretation of Section 112(c)(9) as allowing it to exempt the risk-based subcategory is contrary to the plain language of the statute, the EPA's interpretation fails at Chevron step one.").

UARG's request is indistinguishable from the situation before the court in *NRDC*. UARG does not seek to delist coal- and oil-fired EGUs, which is the source category that EPA listed, but rather a portion of that category. UARG also does not dispute that coal-fired EGUs emit carcinogenic HAP. Because UARG's request to delist is contrary to the plain language of CAA section 112(c)(9)(B) and *NRDC*, we are denying the delisting petition.

2. Even Assuming, for the Sake of Argument, That EPA Could Delist a Portion of a Source Category, UARG has Failed to Meet the Requirements of CAA Section 112(c)(9)

Even assuming, for the sake of argument, that EPA could delist a portion of a source category that emits carcinogens, which it cannot, UARG has failed to demonstrate that the requirements for delisting in CAA section 112(c)(9)(i) and (ii) have been met. UARG contends that it used EPA's models and approaches, as well as the most recent data. We have carefully reviewed UARG's analyses, however, and found certain flaws that we believe bias their risk results low. Specifically, we identified flaws in emissions estimation. UARG developed estimates for all EGU facilities using data which pre-date the 2010 ICR emissions measurement data that EPA obtained to support this rule. UARG also relied upon an emissions equation developed by EPRI and DOE to develop its metal emissions estimates. With regard to that approach, the EPA analysis of the ICR data has found that the regression approach is not a good predictor of actual EGU emissions. Furthermore, we found fault with their use of the geometric mean and their outlier analysis for computing emission factors. The EPA analysis has found that the geometric mean approach underpredicts actual emissions by an average of more than seventy percent. This had an especially large impact on the arsenic, chromium, and nickel emissions estimates. These and other issues are explained in further detail in the response to comments document. As a result, we believe the resulting risk estimates in UARG's analysis are biased low. In addition, we note that there are dispersion model refinements that are not included in the UARG analyses, but were included in EPA's analysis. For example, for the dispersion modeling of the 16 non-Hg case studies, the EPA considered building downwash and used time-varying emissions, neither of which were used in UARG's analysis. These factors could also bias the UARG risk estimates low.

However, even taking UARG's analysis at face value and accepting, for arguments' sake, their assumptions and emissions estimates, UARG's own data supports denial of the petition because UARG itself identifies a maximum individual cancer risk exceeding 1 in a million, which is the statutory threshold in CAA section 112(c)(9)(B)(i). Specifically, UARG's multi-pathway

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model plant ingestion risk analysis concluded that adult anglers would face cancer risks of 4 in a million. For this reason alone, the petition should be denied.

UARG dismisses the 4 in a million cancer result, arguing that the refined model plant multipathway risk assessment that it conducted is "overly conservative." UARG conducted its multi-pathway risk analysis to evaluate the risks associated with ingesting persistent and bioaccumulative HAP which are emitted into the atmosphere and subsequently deposit into the environment and bioaccumulate in animals which are eventually consumed as food. Instead of conducting this multipathway analysis for each EGU facility, UARG instead analyzed multi-pathway risks by evaluating a single model plant. Nothing in the record indicates, however, that UARG's model plant represents the worst-case scenario for cancer human health risks from any EGU. Indeed, although UARG claims in its petition that the site selected for its case study is "likely as close to a worst-case scenario as is possible given the numerous variables associated with ingestion pathway risks" (UARG petition at 12), the supporting documentation for that case study specifically acknowledges that its fictional model plant scenario "is not intended to represent the risk due to emissions from an actual plant or the highest level of risk that could be associated with a coal-fired power plant at any location" (EPRI at 1). The statute requires that no source in the category may cause a lifetime cancer risk greater than one in one million to the most exposed individual, and UARG has failed to make this showing. UARG has neither modeled multi-pathway risks for a worst-case model facility, nor evaluated the multipathway risks associated with each individual EGU facility. Accordingly, UARG has not made the demonstration required by CAA section 112(c)(9)(B)(i). But, even focusing on the multi-pathway risk analysis that UARG did conduct, which admittedly does not represent a worst-case facility, UARG's analysis still shows cancer risks greater than one in a million. Accordingly, UARG's petition must be denied.

Although it is not necessary to reach the requirements of CAA section 112(c)(9)(B)(ii) that address non-cancer human health risks, we note that UARG has also failed to show that "emissions from no source in the category * * * exceed a level which is adequate to protect public health with an ample margin of safety." Again, even accepting, for argument's sake, the conclusions in UARG's analysis, UARG only evaluated the non-cancer *inhalation* risks associated with each EGU facility. It did not conduct a similar analysis to assess multipathway risks for each EGU facility. Instead, it conducted a model plant analysis and admits that such model plant does not represent the worst-case scenario for noncancer human health risks from any EGU. Thus, the analysis fails to fully characterize noncancer multipathway risks for the source category, and UARG's petition must be denied on this basis as well.

Finally, UARG failed to meet its burden of showing that "no adverse environmental effect will result from emissions from any source" pursuant to CAA section 112(c)(9)(B)(ii). UARG analyzed environmental effects only in conjunction with its model plant. Because UARG's model plant does not represent the worst-case scenario for environmental effects, UARG's analysis falls short and fails to characterize fully the potential environmental impacts, and UARG's petition must be denied.

For all of these reasons, the EPA denies UARG's petition to delist coal-fired EGUs from the CAA section 112(c) source category list.

C. EPA's Technical Analyses for the Appropriate and Necessary Finding Provide Further Support for the Conclusion That Coal-Fired EGUs Should Remain a Listed Source Category

The EPA reasonably concluded in December 2000, based on the information available to the Agency at that time, that it was appropriate and necessary to regulate coal- and oil-fired EGUs under CAA section 112 and added such units to the list of source categories subject to regulation under CAA section 112(d). As discussed in section III above, the EPA conducted additional, extensive technical analyses based on recent data that confirm it remains appropriate and necessary to regulate HAP from coal- and oil-fired EGUs, because such EGUs continue to pose hazards to public health. HAP emissions from coal- and oil-fired EGUs also continue to cause adverse environmental effects. UARG advances several arguments, challenging the analyses the Agency completed in support of the proposed rule. We address those arguments in section III above. The Agency's analyses supporting the appropriate and necessary finding confirm that EGUs cannot be delisted pursuant to CAA section 112(c)(9).

Specifically, as explained further in section III above, the EPA analyzed non-Hg inhalation risks from 16 EGU facility case studies, including both coal- and oil-fired EGUs, as part of its technical analyses supporting the appropriate and necessary finding. That analysis demonstrates that there are 6 EGU facilities (of the 16 that we analyzed) with cancer risks exceeding one in one million. These cancer risk levels exceed the delisting criteria set forth in CAA section 112(c)(9)(B)(i), and confirm that EGUs must remain a listed source category. As explained above, some commenters assert that EPA's analysis of non-Hg inhalation risks from EGUs conducted in support of the proposal for this rulemaking overstated emissions from, and risks associated with, EGUs. These commenters argue that the analysis supporting UARG's petition more appropriately assesses EGU risk. The EPA disagrees with these comments and addresses these comments in section III above.

Significantly, the EPA based its analysis of 16 case study EGUs directly on the 2010 emissions test data from EGUs obtained through the ICR. The EPA's 16 case study analysis used emissions data either taken directly from the 2010 emissions test data, or derived using emissions factors based on the 2010 data for similar EGU units. The EPA also included dispersion model refinements in its final case studies, as noted above. Further, the EPA re-analyzed the 16 case studies that we conducted for the proposal and revised those analyses consistent with new non-Hg HAP emissions data and corrected stack parameters provided by commenters (including UARG) during the comment period on the proposed rule. The EPA received revised information concerning emissions tests, stack heights and stack diameters for some of the case study EGU facilities. The EPA incorporated all of these corrections into our analysis and then re-analyzed the risks for the 16 case study facilities. When completed, the EPA determined that the corrections incorporated into the reanalysis had little effect on the overall results. In the final rule, the EPA concludes that the maximum individual inhalation cancer risks for 6 out of the 16 case study EGU facilities are greater than 1 in a million. These cancer risk levels confirm that EGUs do not satisfy the delisting criterion of CAA section 112(c)(9)(B)(i) and thus should remain a listed source category.

The EPA's national-scale Hg Risk TSD supporting the appropriate and necessary finding also confirm that Hg emissions from coal- and oil-fired US EGUs are reasonably anticipated to pose a hazard to public health. As discussed

in section III above, the EPA interprets CAA section 112(n)(1), with regard to mercury, as intended to protect the public, including sensitive populations, against exposures to Hg from EGUs that would exceed the level determined by EPA to be without appreciable risk, e.g., exposures that are above the RfD for methylmercury (MeHg), or would contribute additional risk in areas where Hg exposures exceed the RfD due to contributions from all sources of Hg.

In order to determine whether EGU Hg emissions pose a hazard to public health, the EPA conducted a national-scale Hg Risk TSD focused on populations with high levels of self-caught freshwater fish consumption. The results of the Hg Risk TSD show that 98 percent of modeled watersheds have total exposures to MeHg that exceed the MeHg RfD, above which there is an increased risk of adverse effects on human health. In these watersheds, any reductions in exposures to Hg will reduce risk, and thus the incremental contribution to Hg exposure from any individual source or group of sources, such as EGUs, may reasonably be anticipated to cause additional risk. The Hg Risk TSD focused on those watersheds that either exceeded the RfD based on U.S. EGU attributable deposition alone, without considering other sources of deposition, or watersheds that exceed the RfD due to total Hg deposition and to which U.S. EGUs contributed at least 5 percent of the Hg deposition. The results of that analysis show that up to 29 percent of the modeled watersheds have populations that are potentially at-risk from exposure to Hg from U.S. EGUs, including up to 10 percent of modeled watersheds where deposition from U.S. EGUs alone leads to potential exposures that exceed the MeHg RfD, and up to 24 percent of modeled watersheds where total potential exposures to MeHg exceed the RfD and U.S. EGUs contribute at least 5 percent to Hg deposition. This approach to assessing national risks from Hg deposition from EGUs was supported by the independent peer review conducted by the Science Advisory Board, as discussed fully in section III.

Finally, as discussed in section III, based on this assessment, the EPA has confirmed that Hg emitted from U.S. EGUs pose a hazard to public health and it is appropriate to regulate U.S. EGUs under CAA section 112. This determination and the confirmatory assessments support our conclusion that UARG's delisting petition must be denied.

UARG attempts to dismiss the results of EPA's national-scale Hg Risk TSD, arguing that EPA cannot consider the risks posed by EGUs in conjunction with any other risks, including those from other source categories. Nothing in CAA section 112(c)(9), however, provides that the Agency cannot consider background or emissions due to other sources. CAA section 112(c)(9)(B)(ii) provides that "no source in the category or subcategory concerned (or group of sources in the case of area sources) exceed a level which is adequate to protect public health with an ample margin of safety and no adverse environmental effect will result from emissions from any source." This language could be read to provide that the Agency consider only the risks associated with the source category at issue, and ignore how those risks fit with real-world exposures.[304] However, the language could also be read to provide that the Agency consider the cumulative effect of HAP emissions from the individual sources in the category in conjunction with the HAP emissions from other sources. The latter is a reasonable interpretation, especially when considering how the public is exposed to HAP emissions. Considering the individual sources in a source category in isolation treats the sources as if they exist in a vacuum, which does not mirror reality. Such an approach is particularly problematic for environmentally persistent HAP that bio-accumulate in the food chain, such as mercury.[305]

Here, the record demonstrates that 98 percent of the watersheds EPA modeled have total exposures to MeHg that exceed the MeHg RfD, above which there is increased risk of adverse effects on human health, especially on the developing nervous systems of children during gestation. EGUs remain one of the largest unregulated sources of Hg emissions, and those emissions continue to contribute to Hg exposures and risk. UARG seeks to ignore the fact that exposures above the RfD exist in almost every watershed we modeled, and instead focuses on the contribution provided solely by EGUs. The EPA did as UARG asked and found that up to 10 percent of modeled watersheds where deposition from U.S. EGUs alone leads to potential exposures that exceed the MeHg RfD. Thus, even focusing on EGU emissions in a vacuum, which we do not believe is appropriate or required under CAA section 112(c)(9), we still found that up to 10 percent of the watersheds exceed the RfD due to EGU emissions even before taking into account the numerous other sources of Hg deposition, and we believe this to be an unacceptable percentage of watersheds above the RfD. Due to the persistent, bioacccumulative nature of Hg, among other factors, we believe it is appropriate to consider the combined impact of Hg emissions from EGUs and other sources of Hg. Thus, we also considered the 24 percent of modeled watersheds where, even though U.S. EGU emissions alone are not enough to cause exposures that exceed the RfD, those emissions contribute at least 5 percent of total exposures to MeHg that exceed the RfD. The combined total of 29 percent of modeled watersheds where U.S. EGUs cause or contribute to MeHg exposures above the RfD is clearly unacceptable and thus the UARG petition to delist must be denied.

Thus, the technical analyses the Agency conducted in support of the appropriate and necessary finding confirm that EGUs should remain a listed source category.

[304] The same is true with respect to section 112(c)(9)(B)(i).

[305] In a prior rulemaking, EPA stated that the language in section 112(c)(9)(B)(ii) "does not direct EPA to extend its analysis to either emissions from other sources in other categories or subcategories or to non-attributable background concentrations." 71 FR 8347 (Feb. 16, 2006). The preamble to that rule repeatedly states that the "focus" of the delisting determination in that rule was on emissions from sources in the category under review. *See* 71 FR 8346–47. The preamble went on to compare section 112(c)(9)(B) to section 112(f)(2)(A) in a way that suggested that EPA can consider risks presented by sources other than the subject source category under section 112(f)(2), but not under section 112(c)(9). We do not believe the language of section 112(c)(9) compels any different treatment. The section 112(f) analysis occurs after a source category has already complied with section 112(d) standards, whereas, potential delistings under section 112(c)(9) may involve source categories unregulated by section 112. A delisting decision is significant in that the category that is delisted will no longer be subject to HAP regulation under the Act. It is difficult to justify why we would examine risks from other sources under section 112(f), but not under section 112(c)(9), where Congress established such a specific test for delisting.

V. Summary of This Final NESHAP

This section summarizes the requirements of the final EGU NESHAP. Section VI below summarizes the significant changes to this final rule following proposal.

A. What is the source category regulated by this final rule?

This final rule affects coal- and oil-fired EGUs.

B. What is the affected source?

An existing affected source under this final rule is the collection of coal- or oil-fired EGUs in a subcategory within a single contiguous area and under common control. A new affected source is each coal- or oil-fired EGU for which construction or reconstruction began after May 3, 2011.

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CAA section 112(a)(8) defines an EGU as: a fossil fuel-fired combustion unit of more than 25 megawatts that serves a generator that produces electricity for sale. A unit that cogenerates steam and electricity and supplies more than one-third of its potential electric output capacity and more than 25 megawatts electrical output to any utility power distribution system for sale shall be considered an electric utility steam generating unit.

If an EGU burns coal (either as a primary fuel or as a supplementary fuel) or any combination of coal with another fuel (except for solid waste as noted below) where the coal accounts for more than 10.0 percent of the average annual heat input during any 3 consecutive calendar years or for more than 15.0 percent of the annual heat input during any one calendar year after the applicable compliance date, the unit is considered to be coal-fired under this final rule.

If a unit is not a coal-fired unit and burns only oil or burns oil in combination with a fuel other than coal (except solid waste as noted below) where the oil accounts for more than 10.0 percent of the average annual heat input during any 3 consecutive calendar years or for more than 15.0 percent of the annual heat input during any one calendar year after the applicable compliance date, the unit is considered to be oil-fired under this final rule.

As noted below, the EPA is finalizing in this rule a definition to determine whether the combustion unit is "fossil fuel fired" such that it is considered an EGU as defined in CAA section 112(a)(8) and, thus, potentially subject to this final rule. In addition, using the construct of the definition of "oil-fired" from the ARP, we are finalizing in this rule a requirement that the unit fire coal or oil (or natural gas), or any combination thereof, for more than 10.0 percent of the average annual heat input during any 3 consecutive calendar years or for more than 15.0 percent of the annual heat input during any one calendar year to be considered a "fossil fuel-fired" EGU as defined in CAA section 112(a)(8). However, if a new or existing EGU is not coal- or oil-fired, and the unit burns natural gas exclusively or burns natural gas in combination with another fuel where the natural gas constitutes 10 percent or more of the average annual heat input during any 3 calendar years or 15 percent or more of the annual heat input during any 1 calendar year, the unit is considered to be natural gas-fired EGU and not subject to this final rule. As discussed later, we believe that this definition will address those situations where an EGU co-fires limited amounts of either coal or oil with natural gas or other non-fossil fuels (e.g., biomass).

If an EGU combusts solid waste, standards issued pursuant to CAA section 129 apply to that EGU, rather than this final rule.

C. What are the pollutants regulated by this final rule?

For coal-fired EGUs, this final rule regulates HCl as a surrogate for acid gas HAP, with an alternate of SO_2 as a surrogate for acid gas HAP for coal-fired EGUs with FGD systems installed and operational; filterable PM as a surrogate for non-mercury HAP metals, with total non-mercury HAP metals and individual non-mercury HAP metals as alternative equivalent standards; Hg; and organic HAP. For oil-fired EGUs, this final rule regulates HCl and HF; filterable PM as a surrogate for total HAP metals, with individual HAP metals as alternative equivalent standards; and organic HAP.

D. What emission limits and work practice standards must I meet and what are the subcategories in the final rule?

We are finalizing the emission limitations presented in Tables 3 and 4 of this preamble. Within the two major subcategories of "coal" and "oil," emission limitations were developed for new and existing sources for seven subcategories, two for coal-fired EGUs, one for IGCC EGUs burning synthetic gas derived from coal- and/or solid oil-derived fuel, one for solid oil-derived fuel-fired EGUs, and four for liquid oil-fired EGUs, as described in more detail below. The limited-use liquid oil-fired subcategory, discussed elsewhere in this preamble, is not presented in Table 3 because only work practice standards apply to this subcategory.

TABLE 3—EMISSION LIMITATIONS FOR COAL-FIRED AND SOLID OIL-DERIVED FUEL-FIRED EGUS

Subcategory	Filterable particulate matter	Hydrogen chloride	Mercury
Existing—Unit not low rank virgin coal	3.0E–2 lb/MMBtu. (3.0E–1 lb/MWh)	2.0E–3 lb/MMBtu. (2.0E–2 lb/MWh)	1.2E0 lb/TBtu. (1.3E–2 lb/GWh).
Existing—Unit designed low rank virgin coal	3.0E–2 lb/MMBtu. (3.0E–1 lb/MWh)	2.0E–3 lb/MMBtu. (2.0E–2 lb/MWh)	1.1E+1 lb/TBtu. (1.2E–1 lb/GWh). 4.0E0 lb/TBtu [a]. (4.0E–2 lb/GWh [a]).
Existing—IGCC	4.0E–2 lb/MMBtu. (4.0E–1 lb/MWh)	5.0E–4 lb/MMBtu. (5.0E–3 lb/MWh)	2.5E0 lb/TBtu. (3.0E–2 lb/GWh).
Existing—Solid oil-derived	8.0E–3 lb/MMBtu. (9.0E–2 lb/MWh)	5.0E–3 lb/MMBtu. (8.0E–2 lb/MWh)	2.0E–1 lb/TBtu. (2.0E–3 lb/GWh).
New—Unit not low rank virgin coal	7.0E–3 lb/MWh	4.0E–4 lb/MWh	2.0E–4 lb/GWh.
New—Unit designed for low rank virgin coal	7.0E–3 lb/MWh	4.0E–4 lb/MWh	4.0E–2 lb/GWh.
New—IGCC	7.0E–2 lb/MWh [b] 9.0E–2 lb/MWh [c]	2.0E–3 lb/MWh [d]	3.0E–3 lb/GWh [e].
New—Solid oil-derived	2.0E–2 lb/MWh	4.0E–4 lb/MWh	2.0E–3 lb/GWh.

Note: lb/MMBtu = pounds pollutant per million British thermal units fuel input.
lb/TBtu = pounds pollutant per trillion British thermal units fuel input.
lb/MWh = pounds pollutant per megawatt-hour electric output (gross).
lb/GWh = pounds pollutant per gigawatt-hour electric output (gross).
[a] Beyond-the-floor limit as discussed elsewhere.
[b] Duct burners on syngas; based on permit levels in comments received.

[c] Duct burners on natural gas; based on permit levels in comments received.
[d] Based on best-performing similar source.
[e] Based on permit levels in comments received.

TABLE 4—EMISSION LIMITATIONS FOR LIQUID OIL-FIRED EGUS

Subcategory	Filterable particulate matter	Hydrogen chloride	Hydrogen fluoride
Existing—Liquid oil—continental	3.0E–2 lb/MMBtu (3.0E–1 lb/MWh)	2.0E–3 lb/MMBtu (1.0E–2 lb/MWh)	4.0E–4 lb/MMBtu. (4.0E–3 lb/MWh).
Existing—Liquid oil—non-continental	3.0E–2 lb/MMBtu (3.0E–1 lb/MWh)	2.0E–4 lb/MMBtu (2.0E–3 lb/MWh)	6.0E–5 lb/MMBtu. (5.0E–4 lb/MWh).
New—Liquid oil—continental	7.0E–2 lb/MWh	4.0E–4 lb/MWh	4.0E–4 lb/MWh.
New—Liquid oil—non-continental	2.0E–1 lb/MWh	2.0E–3 lb/MWh	5.0E–4 lb/MWh.

We are also finalizing alternate equivalent emission standards (for certain subcategories) to the final surrogate standards in three areas: SO_2 (for HCl), individual non-mercury metals and total non-mercury metals (for filterable PM) from coal- and solid oil-derived fuel-fired EGUs, and individual and total metals (for filterable PM) from oil-fired EGUs. The final alternate emission limitations are provided in Tables 5 and 6 of this preamble.

TABLE 5—ALTERNATE EMISSION LIMITATIONS FOR EXISTING COAL- AND OIL-FIRED EGUS

Subcategory/Pollutant	Coal-fired EGUs	IGCC	Liquid oil, continental	Liquid oil, non-continental	Solid oil-derived
SO_2	2.0E–1 lb/MMBtu (1.5E0 lb/MWh)	NA	NA	NA	3.0E–1 lb/MMBtu. (2.0E0 lb/MWh).
Total non-mercury metals	5.0E–5 lb/MMBtu (5.0E–1 lb/GWh)	6.0E–5 lb/MMBtu (5.0E–1 lb/GWh)	8.0E–4 lb/MMBtu (8.0E–3 lb/MWh)[a]	6.0E–4 lb/MMBtu (7.0E–3 lb.MWh)[a]	4.0E–5 lb/MMBtu. (6.0E–1 lb/GWh).
Antimony, Sb	8.0E–1 lb/TBtu (8.0E–3 lb/GWh)	1.4E0 lb/TBtu (2.0E–2 lb/GWh)	1.3E+1 lb/TBtu (2.0E–1 lb/GWh)	2.2E0 lb/TBtu (2.0E–2 lb/GWh)	8.0E–1 lb/TBtu. (8.0E–3 lb/GWh).
Arsenic, As	1.1E0 lb/TBtu (2.0E–2 lb/GWh)	1.5E0 lb/TBtu (2.0E–2 lb/GWh)	2.8E0 lb/TBtu (3.0E–2 lb/GWh)	4.3E0 lb/TBtu (8.0E–2 lb/GWh)	3.0E–1 lb/TBtu. (5.0E–3 lb/GWh).
Beryllium, Be	2.0E–1 lb/TBtu (2.0E–3 lb/GWh)	1.0E–1 lb/TBtu (1.0E–3 lb/GWh)	2.0E–1 lb/TBtu (2.0E–3 lb/GWh)	6.0E–1 lb/TBtu (3.0E–3 lb/GWh)	6.0E–2 lb/TBtu. (6.0E–4 lb/GWh).
Cadmium, Cd	3.0E–1 lb/TBtu (3.0E–3 lb/GWh)	1.5E–1 lb/TBtu (2.0E–3 lb/GWh)	3.0E–1 lb/TBtu (2.0E–3 lb/GWh)	3.0E–1 lb/TBtu (3.0E–3 lb/GWh)	3.0E–1 lb/TBtu. (4.0E–3 lb/GWh).
Chromium, Cr	2.8E0 lb/TBtu (3.0E–2 lb/GWh)	2.9E0 lb/TBtu (3.0E–2 lb/GWh)	5.5E0 lb/TBtu (6.0E–2 lb/GWh)	3.1E+1 lb/TBtu (3.0E–1 lb/GWh)	8.0E–1 lb/TBtu. (2.0E–2 lb/GWh).
Cobalt, Co	8.0E–1 lb/TBtu (8.0E–3 lb/GWh)	1.2E0 lb/TBtu (2.0E–2 lb/GWh)	2.1E+1 lb/TBtu (3.0E–1 lb/GWh)	1.1E+2 lb/TBtu (1.4E0 lb/GWh)	1.1E0 lb/TBtu. (2.0E–2 lb/GWh).
Lead, Pb	1.2E0 lb/TBtu (2.0E–2 lb/GWh)	1.9E+2 lb/MMBtu (1.8E0 lb/MWh)	8.1E0 lb/TBtu (8.0E–2 lb/GWh)	4.9E0 lb/TBtu (8.0E–2 lb/GWh)	8.0E–1 lb/TBtu. (2.0E–2 lb/GWh).
Manganese, Mn	4.0E0 lb/TBtu (5.0E–2 lb/GWh	2.5E0 lb/TBtu (3.0E–2 lb/GWh)	2.2E+1 lb/TBtu (3.0E–1 lb/GWh)	2.0E+1 lb/TBtu (3.0E–1 lb/GWh)	2.3E0 lb/TBtu. (4.0E–2 lb/GWh).
Mercury, Hg	NA	NA	2.0E–1 lb/TBtu (2.0E–3 lb/GWh)	4.0E–2 lb/TBtu (4.0E–4 lb/GWh).	NA.
Nickel, Ni	3.5E0 lb/TBtu (4.0E–2 lb/GWh)	6.5E0 lb/TBtu (7.0E–2 lb/GWh)	1.1E+2 lb/TBtu (1.1E0 lb/GWh)	4.7E+2 lb/TBtu (4.1E0 lb/GWh)	9.0E0 lb/TBtu. (2.0E–1 lb/GWh).
Selenium, Se	5.0E0 lb/TBtu (6.0E–2 lb/GWh)	2.2E+1 lb/TBtu (3.0E–1 lb/GWh)	3.3E0 lb/TBtu (4.0E–2 lb/GWh)	9.8E0 lb/TBtu (2.0E–1 lb/GWh)	1.2E0 lb/TBtu. (2.0E–2 lb/GWh).

NA = Not applicable.
[a] Includes Hg.

TABLE 6—ALTERNATE EMISSION LIMITATIONS FOR NEW COAL- AND OIL-FIRED EGUS

Subcategory/Pollutant	Coal-fired EGUs	IGCC[a]	Liquid oil, continental, lb/GWh	Liquid oil, non-continental, lb/GWh	Solid oil-derived
SO_2	4.0E–1 lb/MWh	4.0E–1 lb/MWh	NA	NA	4.0E–1 lb/MWh
Total non-mercury metals	6.0E–2 lb/GWh	4.0E–1 lb/GWh	2.0E–4 lb/MWh[b]	7.0E–3 lb/MWh[b]	6.0E–1 lb/GWh
Antimony, Sb	8.0E–3 lb/GWh	2.0E–2 lb/GWh	1.0E–2	8.0E–3	8.0E–3 lb/GWh
Arsenic, As	3.0E–3 lb/GWh	2.0E–2 lb/GWh	3.0E–3	6.0E–2	3.0E–3 lb/GWh
Beryllium, Be	6.0E–4 lb/GWh	1.0E–3 lb/GWh	5.0E–4	2.0E–3	6.0E–4 lb/GWh
Cadmium, Cd	4.0E–4 lb/GWh	2.0E–3 lb/GWh	2.0E–4	2.0E–3	7.0E–4 lb/GWh
Chromium, Cr	7.0E–3 lb/GWh	4.0E–2 lb/GWh	2.0E–2	2.0E–2	6.0E–3 lb/GWh
Cobalt, Co	2.0E–3 lb/GWh	4.0E–3 lb/GWh	3.0E–2	3.0E–1	2.0E–3 lb/GWh
Lead, Pb	2.0E–3 lb/GWh	9.0E–3 lb/GWh	8.0E–3	3.0E–2	2.0E–2 lb/GWh
Mercury, Hg	NA	NA	1.0E–4	4.0E–4	2.0E–3 lb/GWh
Manganese, Mn	4.0E–3 lb/GWh	2.0E–2 lb/GWh	2.0E–2	1.0E–1	7.0E–3 lb/GWh

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TABLE 6—ALTERNATE EMISSION LIMITATIONS FOR NEW COAL- AND OIL-FIRED EGUS—Continued

Subcategory/Pollutant	Coal-fired EGUs	IGCC [a]	Liquid oil, continental, lb/GWh	Liquid oil, non-continental, lb/GWh	Solid oil-derived
Nickel, Ni	4.0E–2 lb/GWh	7.0E–2 lb/GWh	9.0E–2	4.1E0	4.0E–2 lb/GWh
Selenium, Se	6.0E–3 lb/GWh	3.0E–1 lb/GWh	2.0E–2	2.0E–2	6.0E–3 lb/GWh

NA = Not applicable.
[a] Based on best-performing similar source.
[b] Includes Hg.

As noted elsewhere in this preamble, we are finalizing a requirement to use filterable PM as a surrogate for the non-mercury metallic HAP and HCl as a surrogate for the acid gas HAP for all subcategories of coal-fired EGUs and for the solid oil derived fuel-fired EGUs. For all liquid oil-fired EGUs, we are finalizing a requirement to use filterable PM as a surrogate for the total metallic HAP, and we are finalizing HCl and HF limits.

In addition, we are finalizing alternative standards for certain HAP for some subcategories. The alternative pollutants and subcategories are as follows: (1) SO_2 as a surrogate to HCl for all subcategories with add-on FGD systems (except liquid oil-fired subcategories as there were no existing units from which to base an alternate SO_2 limit); (2) individual non-mercury metallic HAP as an alternate to filterable PM for all subcategories (except that it includes Hg for liquid oil-fired subcategories); and (3) total non-mercury metallic HAP as an alternate to filterable PM for all subcategories (except that it includes Hg for liquid oil-fired subcategories). These alternative standards are discussed elsewhere in this preamble.

We are finalizing a beyond-the-floor standard for Hg only for all existing coal-fired units designed for low rank virgin coal based on the use of activated carbon injection (ACI) for Hg control, as described elsewhere in this preamble. The EPA has determined that this beyond-the-floor level is achievable after considering the relevant CAA section 112(d)(2) provisions.

As noted elsewhere in this preamble, we are also finalizing a compliance assurance option that would allow you to monitor liquid oil fuel moisture to demonstrate that fuel moisture content is no greater than 1.0 percent. Provided that demonstration is made, you will not have to conduct additional testing and monitoring to demonstrate compliance with the HCl and HF emission limits for units in both liquid oil subcategories (*i.e.*, continental and non-continental).

Pursuant to CAA section 112(h), we are finalizing a work practice standard for organic HAP, including emissions of dioxins and furans, for all subcategories of EGUs. The work practice standard being finalized requires the implementation of periodic burner tune-up procedures described elsewhere in this preamble. We are finalizing work practice standards because the significant majority of data for measured organic HAP emissions from EGUs are below the detection levels of the EPA test methods, even when long duration (around 8 hour) test runs are considered. As such, we consider it impracticable to measure emissions from these units. As discussed at proposal, we believe the inaccuracy of a majority of measurements, coupled with the extended sampling times used, allow a work practice standard under CAA section 112(h) to apply to these HAP.[306] We believe that a work practice standard will lead to a better environmental outcome than would be obtained through a requirement to measure a pollutant for which results may or may not be obtained. We believe that the work practice standard will result in actions being taken that will reduce emissions of these HAP.

In addition, as discussed below, we are creating a subcategory for limited use liquid oil-fired electric utility steam generating unit with an annual capacity factor of less than 8 percent of its maximum or nameplate heat input and we are establishing work practice standards applicable to such units pursuant to CAA section 112(h).

We are finalizing that new or existing EGUs are "coal-fired" if they combust coal more than 10 percent of the average annual heat input during any 3 consecutive calendar years or for more than 15 percent of the annual heat input during any one calendar year and meet the final definition of "fossil fuel-fired." We are finalizing that an EGU is considered to be in the coal-fired "unit designed for coal greater than or equal to 8,300 Btu/lb" subcategory if the EGU: (1) meets the final definitions of "fossil fuel-fired" and "coal-fired electric utility steam generating unit;" and (2) is not a coal-fired EGU in the "unit designed for low rank virgin coal" subcategory.

We are finalizing that the EGU is considered to be in the "unit designed for low rank virgin coal" subcategory if the EGU: (1) meets the final definitions of "fossil fuel-fired" and "coal-fired electric utility steam generating unit;" and (2) is designed to burn and is burning nonagglomerating virgin coal having a calorific value (moist, mineral matter-free basis) of less than 19,305 kJ/kg (8,300 Btu/lb) and that is constructed and operates at or near the mine that produces such coal.[307]

We are finalizing that the EGU is considered to be an IGCC unit if the EGU: (1) Combusts a synthetic gas derived from gasified coal or solid oil-derived fuel (*e.g.*, petroleum coke, pet coke), (2) meets the final definition of "fossil fuel-fired," and (3) is classified as an IGCC unit. We are not subcategorizing IGCC EGUs based on the source of the syngas used (e.g., coal, petroleum coke). Based on information available to the Agency, although the fuel characteristics of coal and petcoke are quite different, the syngas products from both feedstocks have similar HAP content and similar HAP emissions characteristics that can be controlled in a similar manner.[308]

We are finalizing that the EGU is considered to be in the "Continental liquid oil-fired" subcategory if (1) meets the final definitions of "oil-fired electric utility steam generating unit" and "fossil fuel-fired;" and (2) is located in the continental United States (U.S.).

We are finalizing that the EGU is considered to be "Non-continental liquid oil-fired" subcategory if (1) meets the final definitions of "oil-fired electric utility steam generating unit" and

[306] We would also note that the EPA, as a part of the Industrial Boiler MACT reconsideration proposal that was signed on December 2, 2011, is proposing to establish work practice standards for control of dioxins and furans from industrial boilers.

[307] ASTM Method D388–05, "Standard Classification of Coals by Rank" (incorporated by reference, see § 63.14).

[308] U.S. Department of Energy, Wabash River Coal Gaification Repowering Project. Project Performance Summary; Clean Coal Technology Demonstration Program. DOE/FE–0448. July 2002. EPA–HQ–OAR–2009–0234–2933.

"fossil fuel-fired;" and (2) is located outside continental U.S.

We are finalizing that the EGU is considered to be "solid oil-derived fuel-fired" if (1) the EGU is not a coal-fired EGU and burns solid oil-derived fuel (*e.g.*, petroleum coke, pet coke); and (2) meets the final definitions of "oil-fired electric utility steam generating unit" and "fossil fuel-fired."

We are finalizing that the EGU is considered to be a "limited-use liquid oil-fired" if (1) the EGU meets the final definitions of "oil-fired electric utility steam generating unit" and "fossil fuel-fired;" and (2) has an annual capacity factor of less than 8 percent of its maximum or nameplate heat input, whichever is greater, averaged over a 24-month block contiguous period commencing.

E. What are the requirements during periods of startup, shutdown, and malfunction?

As discussed below in section VI.E., for startup and shutdown, the requirements have changed since proposal. For periods of startup and shutdown, the EPA is finalizing work practice standards in lieu of numeric emission limits. Numeric emission limits apply for all other periods for all pollutants, except organic HAP. For malfunctions, the EPA is finalizing an affirmative defense for exceedances of the numerical emission limits that are caused by malfunctions.

F. What are the testing and initial compliance requirements?

We are requiring that you, as an owner or operator of a new or existing coal- or oil-fired EGU, must conduct performance tests to demonstrate compliance with all applicable emission limits. For units using certified continuous emissions monitoring systems (CEMS) that directly measure the regulated pollutant under final 40 CFR part 63, subpart UUUUU (*e.g.*, Hg CEMS, HCl CEMS, HF CEMS, SO_2 CEMS (where an SO_2 limit applies as the alternative equivalent standard)), or sorbent trap monitoring systems, the initial performance test consists of all valid data recorded with the certified monitoring system in the first 30 boiler operating days of data collected with the certified monitoring system prior to the initial compliance demonstration date specified in § 63.10005. A source may also elect to use a PM CEMS to demonstrate compliance with the filterable PM emission limit. If this option is selected, then the same provisions as noted above for other CEMS will apply. (Note that EPA anticipates that the PM monitoring device that may most often will be used is a PM continuous parameter monitoring system (CPMS) in conjunction with an operating limit, as more fully described below.) For units and pollutants not being monitored via CEMS, the owner or operator of an affected unit must perform the initial performance testing in accordance with established EPA reference test methods or the voluntary consensus standard methods incorporated by reference. You, as the owner or operator of an affected unit, must conduct the following compliance tests where applicable:

(1) For coal-fired units, IGCC units, and solid oil-derived fuel-fired units, if you elect to comply with the filterable PM emission limit, you must conduct filterable PM emissions testing using EPA Method 5 from Appendix A to part 60 of chapter 40 to determine initial compliance. Alternatively, if you elect to comply with the total non-mercury HAP metals emission limit or the individual non-mercury HAP metals emissions limits, you must conduct HAP metals testing using EPA Method 29 from Appendix A to part 60 of chapter 40. Note for this rule that the filter temperature for each Method 5 or 29 emissions test must be maintained at 160° ± 14 °C (320 ° ± 25 °F), and the material in Method 29 impingers must be analyzed for metals content. Whenever metals testing is performed with Method 29, you must report the front half and back half analytical fractions separately.

(2) For coal-fired, IGCC, and solid oil-derived fuel-fired units, you must use a Hg CEMS or a sorbent trap monitoring system for both initial compliance and continuous compliance using the continuous Hg monitoring provisions of Appendix A to 40 CFR part 63, subpart UUUUU, except where the low emitting EGU (LEE) requirements apply (see below). The initial performance test consists of all valid data recorded with the certified Hg monitoring system in the 30 boiler operating days of data collected with the certified monitoring system by the initial compliance demonstration date specified in § 63.10005.

(3) For coal-fired and solid oil-derived fuel-fired units and new or reconstructed IGCC units that employ FGD technology and elect to meet the alternative SO_2 limit in place of the HCl limit, you need not conduct an initial stack test for HCl or SO_2. Instead, the 30 boiler operating days of data collected with the certified SO_2 CEMS by the initial compliance demonstration date specified in § 63.10005 are used to determine initial compliance, and the SO_2 CEMS is used thereafter to demonstrate continuous compliance. If you instead opt to meet the HCl limit and use an HCl CEMS for compliance, you need not conduct an initial stack test for HCl. Instead, the 30 boiler operating days of data collected with the certified HCl CEMS by the initial compliance demonstration date specified in § 63.10005 are used to determine initial compliance. For units not using the SO_2 or HCl CEMS options, you must conduct an initial stack test for HCl using EPA Method 26, 26A, or 320 from Appendix A to part 60 of chapter 40. You may use EPA Method 26 or 320 or ASTM Method D6348–03 (Reapproved 2010) with additional quality assurance if no entrained water droplets exist in the exhaust gas, but you must use Method 26A if entrained water droplets exist in the exhaust gas.

(4) For liquid oil-fired units, you must conduct initial performance testing as follows. If you elect to meet the filterable PM limit instead of the non-mercury metals limit (total or individual), then use Method 5 with the filter material maintained at 160° ± 14°C (320° ± 25°F). Alternatively, you may use a PM CEMS as discussed elsewhere in this preamble. If you elect to meet either the total or individual HAP metals limit, you will use Method 29 for all non-mercury HAP metals. For Hg, conduct emissions testing using EPA Method 29 or 30B from Appendix A to part 60 of chapter 40, or ASTM Method D6784–02 (Reapproved 2008). For acid gases, conduct HCl and HF testing using EPA Method 26A, 320, or 26; or you may elect to comply by using an HCl CEMS and/or an HF CEMS; or under certain conditions you may choose to demonstrate compliance by measuring fuel moisture to demonstrate that moisture content is no greater than 1.0 percent. You must measure daily if fuel is delivered continuously or per shipment if fuel is delivered on a batch basis, or you may use a fuel moisture content certification provided by your fuel supplier. If you use a CEMS, then use the 30 boiler operating days of data collected with the certified monitoring system by the initial compliance demonstration date specified in § 63.10005 to determine initial compliance.

(5) For the required performance stack tests, if you are demonstrating compliance with a heat-input based standard, you must conduct concurrent O_2 or carbon dioxide (CO_2) emission testing using EPA Method 3A or 3B from appendix A to part 60 of chapter 40 or ANSI/ASME PTC 19.10–1981 and then use an appropriate equation, selected from among Equations 19–1

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through 19–9 in EPA Method 19 from appendix A to part 60 of chapter 40, to convert measured pollutant concentrations to lb/MMBtu values. Multiply the lb/MMBtu value by one million to get the lb/TBtu value (where applicable). If you choose to meet an electrical output-based emissions limit, you must also collect concurrent stack gas flow rate and electrical production data.

(6) For an existing unit that you believe will qualify as LEE for Hg, you must conduct an initial Method 30B test over 30 days and follow the calculation procedures in the final rule to document a potential to emit less than 10 percent of the applicable Hg emissions limit or less than 29 pounds of Hg per year. If your unit qualifies as a LEE for Hg, you must conduct subsequent performance tests on an annual basis to demonstrate that the unit continues to qualify. For all other pollutants, you must conduct the initial compliance test, and then all other required tests over a 3-year period, and in all such tests, your emission results must be less than 50 percent of the applicable emission limit. If you qualify as a LEE on that basis, you must conduct subsequent performance tests every 3 years to demonstrate that the unit continues to qualify.

(7) You may use results from tests conducted no earlier than 12 months before the compliance date of this rule as the initial performance test for an applicable pollutant, provided that:

a. You certify and keep records demonstrating that no significant changes have occurred,

b. Tests were conducted using methods allowed in this rule in accordance with § 63.10007 and Table 5,

c. You have records of all parameters needed to convert results to units of the standard for the entire period, and

d. For a CEMS-based performance test, you have all the required data for the entire 30-boiler operating day rolling average period.

Operating Limit for PM CEMS

Under the final rule, you may elect to comply continuously with an operating limit, established during the initial performance test, to demonstrate continuous compliance with the filterable PM, total non-mercury HAP metals, or individual non-mercury HAP metals limit. You will use a PM CPMS to monitor compliance with the operating limit. The PM CPMS operating principle must be based on in-stack or extractive light scatter, light scintillation, beta attenuation, or mass accumulation detection of the exhaust gas or representative exhaust gas sample. The reportable measurement output from the PM CPMS may be expressed as milliamps, stack concentration, or other raw data signal. Meeting the operating limit serves as your demonstration of continuous compliance with the filterable PM, total non-mercury HAP metals, or individual non-mercury HAP metals limit. As mentioned earlier, if you use this method to demonstrate continuous compliance, you must install a PM CPMS and establish the operating limit during the initial compliance test for filterable PM, total non-mercury HAP metals, or individual non-mercury HAP metals. As noted below, when you use this operating limit, you can reduce stack testing frequency to demonstrate ongoing compliance. You may also opt to install and operate a PM CEMS certified in accordance with Performance Specification 11 and Procedure 2 of 40 CFR part 60, Appendices B and F, respectively. If you elect to use this option, then the requirements for quarterly testing with Method 5, or annual testing and use of a PM CPMS, are no longer applicable.

Dioxins/Furans and Non-Dioxin/Furan Organic HAP

For dioxins and furans and non-dioxin/furan organic HAP, you must submit documentation that you have conducted a combustion process tune-up, a thorough equipment inspection, and an optimization to minimize generation of CO and NO_X, all meeting the requirements of this final rule. The work practice standard involves maintaining and inspecting the burners and associated combustion controls, tuning the specific burner type to optimize combustion, obtaining and recording CO and NO_X values before and after burner adjustments, keeping records of activity and measurements, and submitting a report for each tune-up conducted. You must collect CO and NO_X data and may use portable analyzers (which include handheld or similar devices) to monitor and verify the results. The specific details are addressed in 40 CFR 63.10021 of the final rule.

This same work practice standard also applies in place of any emission limits for Hg, non-mercury metals HAP, acid gas HAP, dioxins and furans, and non-dioxin/furan organic HAP from a limited-use, liquid oil-fired EGU (*i.e.*, a unit that has an annual capacity factor on oil of less than 8 percent of its maximum or nameplate heat input, whichever is greater). The EPA established this subcategory in response to comments and a further analysis of the units within this subcategory in the ICR database. For these units, EPA believes that the required work practice standards are appropriate and consistent with the requirement of CAA section 112(h).

G. What are the continuous compliance requirements?

To demonstrate continuous compliance with the emission limitations, the final rule includes the following requirements:

(1) *Use of CEMS.* Where a CEMS or a sorbent trap monitoring system is used for demonstrating initial compliance, you also must use the CEMS or sorbent trap monitoring system on a continuous basis to demonstrate ongoing compliance with the numerical emission limits. CEMS or sorbent trap monitoring system data are not used to determine compliance with the work practice standards applicable during periods of startup and shutdown, but sources that install a CEMS or a sorbent trap monitoring system to demonstrate compliance with the numerical emission limits must operate the system at all times, as EPA intends to evaluate the continuous monitoring data from start-up and shutdown periods as discussed below. You must calculate a rolling average for each successive 30-boiler operating day rolling average period. All valid data collected during each successive period will be used to demonstrate compliance, except for data collected during periods of startup and shutdown; during those periods, the owner or operator must meet work practice requirements instead of the numerical emission limits. There is no numerical minimum data availability required to constitute a valid 30-boiler operating day rolling average; however, you must monitor at all times that the process is in operation (including during startups and shutdowns, although emissions during these periods are not included in the 30-boiler operating day average). You must operate, maintain, and quality-assure the CEMS or sorbent trap monitoring systems in accordance with the provisions in 40 CFR 63.10010 and Appendix A and B of the final rule (for Hg, HCl, and HF CEMS), in accordance with Performance Specification 11 in Appendix B to 40 CFR part 60 and Procedure 2 in Appendix F to part 60 (for PM CEMS used for direct compliance), or in accordance with 40 CFR part 75 (for SO_2 CEMS, and certain ancillary monitors such as a diluent or moisture monitor).

For each unit using HCl, HF, SO_2, PM, or Hg CEMS or a sorbent trap monitoring system for continuous compliance, you must install, certify, maintain, operate and quality-assure the

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additional CEMS (*e.g.*, CEMS that measure O_2 or CO_2 concentration, stack gas flow rate, and, if default moisture values are not used, moisture content) needed to convert pollutant concentrations to units of the emission standards or operating limits. Where appropriate, you must certify and quality-assure these additional CEMS according to 40 CFR part 75.

For HCl and HF CEMS, the EPA is adding monitoring provisions as Appendix B to 40 CFR part 63, subpart UUUUU. Appendix A references performance specification (PS) 15 of Appendix B to 40 CFR part 60 for Fourier Transform Infrared (FTIR) CEMS for procedures to certify and conduct ongoing quality assurance on these FTIR CEMS. In addition, we expect to publish a PS specific to HCl CEMS in the near future (prior to the compliance date of this rule). In the meantime, you may petition the Administrator under the procedure given in 40 CFR 63.7(f) for an alternative approach to compliance monitoring or testing for HCl or any other regulated pollutant.

When using a sorbent trap monitoring system, you may use each pair of sorbent traps to collect Hg samples for no more than 15 boiler operating days. Under the general duty to monitor at all times, you must replace traps in a timely manner to ensure that Hg emissions are sampled continuously.

For Hg monitoring, the EPA is adding Hg monitoring provisions as Appendix A to 40 CFR part 63, subpart UUUUU, and requiring use of these provisions to document continuous compliance with the rule for coal-fired, IGCC, and solid oil derived-fired units that cannot qualify as LEEs. Appendix A consolidates all Hg monitoring provisions.

Today's rule provides two basic Hg continuous monitoring options: Hg CEMS and sorbent trap monitoring systems. Appendix A requires initial certification and periodic quality assurance (QA) testing of the Hg CEMS and sorbent trap monitoring systems. The certification tests required for the Hg CEMS are a 7-day calibration error test; a linearity check, using NIST-traceable elemental Hg standards; a 3-level system integrity check (similar to a linearity check), using NIST-traceable oxidized Hg standards; a cycle time test; and a relative accuracy test audit (RATA). Table A–1 of Appendix A summarizes the performance specifications for the required certification tests. For ongoing QA of the Hg CEMS, Appendix A requires daily calibrations, weekly single-point system integrity checks, quarterly linearity checks (or 3-level system integrity checks), and annual RATAs. Table A–2 in Appendix A summarizes these ongoing QA test requirements and the applicable performance criteria for Hg CEMS, which are consistent with those published in support of CAMR and are, thus, familiar to the industry.

For sorbent trap monitoring systems, a RATA is required for initial certification, and annual RATAs are required for ongoing QA. The performance specification for these RATAs is the same as for the RATAs of the Hg CEMS. Bias adjustment of the measured Hg concentration data is not required. For day-to-day operation of the sorbent trap system, Appendix A requires you to follow the procedures and QA/QC criteria in PS 12B in Appendix B to 40 CFR part 60. PS 12B is nearly identical to the Appendix K to 40 CFR part 75, published in support of CAMR and with which the industry is familiar. The 40 CFR part 75 concepts of:

a. Determining the due dates for certain QA tests on the basis of "QA operating quarters" and

b. Grace periods for certain QA tests apply to both Hg CEMS and sorbent trap monitoring systems. Mercury concentrations measured by Hg CEMS or sorbent trap systems are used together with hourly flow rate, diluent gas, moisture, and electrical load data, to express the Hg emissions in units of the rule, on an hourly basis (*i.e.*, lb/TBtu or lb/GWh). Section 6 of Appendix A provides the necessary equations for these unit conversions.

For HCl and HF CEMS, the EPA is adding monitoring provisions as Appendix B to 40 CFR part 63, Subpart UUUUU. Appendix A references performance specification (PS) 15 of Appendix B to 40 CFR part 60 for Fourier Transform Infrared (FTIR) CEMS for procedures to certify and conduct ongoing quality assurance on these FTIR CEMS. In addition, we expect to promulgate a generic PS specific to HCl CEMS prior to the compliance date of this rule. In the meantime, you may petition the Administrator under the procedure given in 40 CFR 63.7(f) for an alternative approach to compliance monitoring or testing for HCl or any other regulated pollutant.

(2) *Use of stack tests.* If you demonstrate initial compliance on the basis of a stack test, you must demonstrate continuous compliance by conducting periodic stack tests on a quarterly basis. This includes filterable PM (or non-mercury HAP metals) and HCl from coal-fired and solid oil-derived fuel-fired EGUs, and filterable PM (or HAP metals) and HCl and HF from liquid oil-fired EGUs with the following exceptions:

a. If you use a PM CPMS and associated operating limit, you may conduct the applicable Method 5 or Method 29 test once annually rather than quarterly, in which case you must re-establish the operating limit during each performance test. A PM CPMS does not need to meet the requirements for a PM CEMS under PS 11. The final rule includes basic quality checks that the PM CPMS must meet and a requirement for you to develop and follow a site-specific monitoring plan to be approved by the delegated authority. You must demonstrate compliance with the operating limit by using all valid hourly data collected during each successive 30-boiler operating day period rolled daily. The 30-boiler operating day rolling average is calculated by all of the valid hourly average PM CPMS output values collected for the 30 boiler operating days (excluding hours of startup and shutdown; *see* section V.E. of this preamble).

b. If you combust liquid fuels and if your fuel moisture content is no greater than 1.0 percent, you may demonstrate ongoing compliance with HCl and HF emissions limits by:

i. Measuring fuel moisture content of each shipment of fuel if your fuel arrives on a batch basis;

ii. Measuring fuel moisture content daily if your fuel arrives on a continuous basis; or

iii. Obtaining and maintaining a fuel moisture certification from your fuel supplier.

Should the moisture in your liquid fuel be more than 1.0 percent, you must

i. Conduct HCl and HF emissions testing quarterly and establish site-specific monitoring to demonstrate continued acid gas control performance between periodic tests, or

ii. Use an HCl CEMS and/or HF CEMS.

c. If your existing unit qualifies as an LEE for Hg, you must conduct another 30-day Method 30B performance test on your unit once per year to reestablish that the unit continues to qualify as a LEE for Hg. If the results of the LEE test show that the unit exceeds 10 percent of the emissions limit or exceeds the potential to emit 29 pounds of Hg per year, you will lose LEE status for the unit. You can regain LEE status for that unit if every required performance test for a 3-year period shows that emissions from the unit did not exceed the LEE limit. If LEE status is lost for a solid fuel unit, you must commence quarterly performance testing until you install,

certify, and operate a Hg CEMS or a sorbent trap monitoring system, and you must complete the installation and certification within 6 months of losing LEE status; for a liquid fuel unit, you must commence quarterly performance testing.

d. If a liquid oil-fired EGU has an annual capacity factor on oil of less than 8 percent of its maximum or nameplate heat input, whichever is greater, you must demonstrate continuous compliance with the applicable work practice standard by conducting at least once every 36 calendar months (48 calendar months if a neural network is employed) a combustion process tune-up, a thorough equipment inspection, and an optimization to minimize generation of CO and NO_X, all meeting the requirements of this final rule. You must maintain and inspect the burners and associated combustion controls, tuning the specific burner type to optimize combustion, obtaining and recording CO and NO_X values before and after burner adjustments, keeping records of activity and measurements, and submitting a report for each tune-up conducted. You must collect CO and NO_X data using portable analyzers (which typically include handheld or similar devices). Specific details are addressed in 40 CFR 63.10021 of the final rule. In addition, you must record boiler operating hours, by fuel type, in each calendar quarter.

e. The rule allows a grant of LEE status to existing units with test results that show a history of low, non-mercury emissions. As mentioned earlier, LEE status reduces testing frequency for units. After a 3-year period during which every emissions test for a specific pollutant shows emissions no greater than 50 percent of the emissions limit, you may reduce the emissions testing frequency for that specific non-mercury pollutant to once every 36 months. If any subsequent emissions test for that pollutant exhibits emissions greater than 50 percent of the emissions limit, you must revert to the original emissions testing frequency until you re-establish a 3-year period of very low emissions no greater than 50 percent of the standard.

f. For liquid oil-fired units that demonstrate continuous compliance with quarterly performance tests for HCl and HF emission limits rather than through use of HCl and HF CEMS, the final rule requires a site-specific monitoring plan in addition to the quarterly tests. For these pollutants, there is unlikely to be any existing underlying monitoring (such as compliance assurance monitoring) that serves as an additional tool to ensure the source's operations remain consistent with operating conditions during a recent successful performance test. The requirement for a site-specific monitoring plan fills this gap and ensures that in between tests, the source continues to operate in a manner designed to maintain HCl and HF emissions in compliance with the emission limits under this rule. The appropriate parameters to monitor will depend on the compliance strategy employed by a specific source, and thus EPA is enabling the monitoring approach to be established on a case-by-case basis. Given the relatively small number of these units and the other compliance options available, we anticipate that this approach will apply to a small set of units. The monitoring plan will identify the parameters monitored, the monitoring methods, the QA/QC elements that apply, and the data reduction elements (including appropriate averaging periods, as applicable). See 40 CFR 63.10000(c)(2)(ii).

(3) *Work practice standard.* For the performance tune-up work practice requirements, you must demonstrate continuous compliance by conducting the work practice at least once every 36 calendar months (48 calendar months if a neural network is employed). The work practice involves maintaining and inspecting the burners and associated combustion controls, tuning the specific burner type, as applicable, to optimize combustion, obtaining and recording CO and NO_X values before and after burner adjustments, keeping records of activity and measurements, and submitting a report for each tune-up conducted. A combustion tune-up will involve optimizing combustion of the unit consistent with manufacturer's instruction as applicable, or in accordance with best combustion engineering practice for that burner type.

H. What are the notification, recordkeeping and reporting requirements?

All new and existing sources in all subcategories must comply with certain requirements of the General Provisions (40 CFR part 63, subpart A), which are identified in Table 9 of this final rule. The General Provisions include specific requirements for notifications, recordkeeping, and reporting. You must submit a notification of compliance status report for each unit, according to the schedule required by 40 CFR 63.9(h) of the General Provisions, including a certification of compliance.

Except for units that use CEMS for continuous compliance, under this rule you must provide semiannual compliance reports, as required by 40 CFR 63.10(e)(3) of subpart A, that indicate whether a deviation from any of the requirements in the rule occurred and whether or not any process changes occurred and compliance certifications were reevaluated. As discussed below, we are finalizing a requirement to use the 40 CFR part 75-based Emissions Collection and Monitoring Plan System (ECMPS) for reporting emissions and related data for units using CEMS for most pollutants. Also, as discussed below, for the PM CPMS, PM CEMS, and performance test results, we require you to use EPA's WebFIRE [309] database for reporting.

This rule requires you to keep certain records to demonstrate compliance with each emission limit and work practice standard. The General Provisions to 40 CFR part 63 specify these recordkeeping requirements (see Table 9 to this subpart). Among other specific records, you must keep the following:

(1) All reports and notifications submitted to comply with this rule.

(2) Continuous monitoring data as required in this rule.

(3) Each instance in which you did not meet an emission limit, work practice requirement, operating limit, or other compliance obligation (*i.e.,* deviations from this rule).

(4) Daily hours of operation by each unit.

(5) As part of the general duty to keep all monitoring data, fuel moisture content of liquid fuel, if you elect to demonstrate compliance using that information.

(6) A copy of the results of all performance tests, monitor certifications, performance evaluations, or other compliance demonstrations conducted to demonstrate initial or continuous compliance with this rule.

(7) A copy of your site-specific performance evaluation test plans developed for this rule as specified in 40 CFR 63.8(e), if applicable.

(8) A copy of your acid gas control system parameter monitoring plan under 40 CFR 63.10000(c)(2)(ii).

You also must submit the following additional notifications:

(1) Notifications required by the General Provisions.

(2) Initial Notification no later than 120 calendar days after you become subject to this subpart.

[309] WebFIRE is the Internet version of FIRE. The Factor Information Retrieval (FIRE) Data System is a database management system containing EPA's recommended emission estimation factors for criteria and HAP. It includes information about industries and their emitting processes, the chemicals emitted, and the emission factors themselves.

(3) Notification of Intent to conduct performance tests and/or compliance demonstration at least 60 calendar days before the performance test and/or compliance demonstration is scheduled.

(4) Notification of Compliance Status 60 calendar days following completion of the performance test and/or compliance demonstration.

Electronic reporting is becoming a common element of modern life (as evidenced by electronic banking and income tax filing), and the EPA is beginning to require electronic submittal of environmental data. Electronic reporting is already common in environmental data collection and many media offices at EPA are reducing reporting burden for the regulated community by embracing electronic reporting systems as an alternative to paper-based reporting.

One of the major benefits of reporting electronically is standardization, to the extent possible, of the data reporting formats that provides more certainty to users of what data are required in specific reports. For example, electronic reporting software allows for more efficient data submittal and the software's validation mechanism helps industry users submit fewer incomplete reports. This alone saves industry report processing resources and reduces transaction times. Standardization also allows for development of efficient methods to compile and store much of the documentation required to be reported by this rule.

Use of Electronic Reporting System

We are requiring that you submit certain reports electronically. In addition to supporting regulation development, control strategy development, and other air pollution control activities, having an electronic database populated with these reports will save industry, state, local, tribal agencies, the public, and the EPA significant time, money, and effort while also improving the transparency and quality of emission inventories and, as a result, air quality regulations.

The reports to be submitted electronically include all performance test reports, notification of compliance status reports, compliance, and continuous monitoring data summaries specified in 40 CFR 63.10031 of this rule. Performance tests are required to be conducted as described in 40 CFR 63.7 of the General Provisions. The data that must be submitted as the performance test report are also described in 40 CFR 63.7. These data must be submitted (except in limited cases) to EPA's WebFIRE database by using the electronic reporting tool (ERT) and the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX), as described below. The data requirements for the notification of compliance status and compliance reports are described in detail in the regulatory text (40 CFR 63.10031) of this rule, but they essentially mirror the requirements in 40 CFR 63.6 of the General Provisions. These reports will also be submitted to WebFIRE using an electronic form found in CEDRI and through the CDX as described below. As required in 40 CFR 63.10031(f)(2) of the final rule, the continuous monitoring summaries are required to be submitted quarterly. The quarterly reports must include all of the calculated 30-boiler operating day rolling average values derived from the PM CPMS. These reports will also be submitted to WebFIRE using an electronic form found in CEDRI and through the CDX, as described below. This same approach will apply if a source elects to use a PM CEMS or receives approval to use a HAP metals CEMS as an alternative monitoring method.

The availability of electronic reporting for sources subject to the Subpart UUUUU will provide efficiency, improved services, better accessibility of information, and more transparency and accountability. Additionally, submittal of these required reports electronically provides significant benefits for regulatory agencies, industry, and the public. The compliance data electronic reporting system (CEDRI and CDX) is being developed such that once a facility's initial data entry into the system is established and a report is generated, subsequent data submittal will only consist of electronic updates to existing information in the system. Such a system will effectively reduce the burden associated with submittal of data and reports by reducing the time, costs, and effort required to submit and update hard copies of documentation. State, local, and tribal air pollution control agencies will also benefit from having access to the more streamlined and accurate electronic data submitted to the EPA. Electronic reporting will allow for an electronic review process rather than a manual data assessment, making review and evaluation of the source-provided data and calculations easier and more efficient. Electronic reporting will also benefit the public by generating a more transparent review process and increasing the ease and efficiency of data accessibility. Furthermore, electronic reporting will reduce the burden on the regulated community by reducing the effort involved in data collection and reporting activities. In the future, we anticipate there will be fewer and less substantial data collection requests in conjunction with prospective required residual risk assessments or technology reviews. Electronic reporting will substantially reduce this burden, because the EPA will already have these data available and consolidated in an electronic database named WebFIRE. We anticipate that using electronic reporting for the required reports will result in an overall reduction in reporting costs; for a discussion of the economic and cost impacts of electronic reporting, see section XII.D. of this preamble.

Another benefit of electronic data submittal is that these data will greatly improve the overall quality of existing and new emissions factors by supplementing the pool of emissions test data for establishing emissions factors and by ensuring that the factors are more representative of current industry operational procedures. A common complaint heard from industry and regulators is that emission factors are outdated or not representative of a particular source category. With timely receipt and incorporation of data from most performance tests, the EPA will be able to ensure that emission factors, when updated, represent the most current range of operational practices.

Data entry of these electronic reports will be through the CEDRI that is accessed through EPA's CDX (*www.epa.gov/cdx*). Data submitted electronically through CEDRI will be stored in CDX as an official copy of record.

Once you have accessed CEDRI, you will select the applicable subpart for the report that you are submitting. You will then select the report being submitted, enter the data into the form, and click on the submit button. In some cases, such as with submittal of a notification of compliance status report, you will select the report icon, enter basic facility information, and then upload the report in a specified file format.

In addition, we believe that there will be value in allowing other reporting forms to be developed and used in cases where the other reporting forms can provide an alternate electronic file consistent with EPA's form output format. This approach has been used successfully to provide alternatives for other electronic forms (*e.g.*, income tax submittal).

In cases where performance test data are to be submitted to the EPA, you must enter the performance test data

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and information into the electronic reporting tool (ERT) which can be accessed at *http://www.epa.gov/ttn/chief/ert/index.html.* In CEDRI, the user must then upload the ERT file. CEDRI submits a copy of the ERT project data file directly to WebFIRE where the data are made available. Where performance test reports are submitted, WebFIRE notifies the appropriate state, local, or tribal agency contact that an ERT project data file was received from the source.

Submitting performance test data electronically to the EPA will apply only to those performance tests conducted using test methods that will be supported by the ERT. The ERT contains a specific electronic data entry form for most of the commonly used EPA reference methods. A listing of the pollutants and test methods supported by the ERT is available at the ERT Web site listed above.

I. Submission of Emissions Test Results to the EPA

The EPA has determined that harmonization of the monitoring and reporting requirements of this final rule with 40 CFR part 75 is appropriate, where the affected industry already has a well-defined system for continuous monitoring and reporting of emissions under that part. Therefore, the Agency is finalizing monitoring and reporting requirements for most CEMS that are consistent with 40 CFR part 75. You must report CEMS data (other than PM CEMS data or data from alternative monitoring subject to site-specific approval such as a HAP metals CEMS) to the EPA electronically, on a quarterly basis, using the ECMPS.

The ECMPS process divides electronic data into three categories, the first of which is monitoring plan data. You must maintain the electronic monitoring plan separately and can update it at any time if necessary. The monitoring plan documents the characteristics of the affected units (*e.g.*, unit type, rated heat input capacity, etc.) and the monitoring methodology used for each parameter (*e.g.*, CEMS). The monitoring plan also describes the type of monitoring equipment used (hardware and software components), includes analyzer span and range settings, and provides other useful information. Nearly all coal-fired EGUs are subject to the ARP and thus have established electronic monitoring plans that describe their required SO_2, flow rate, CO_2 or O_2, and, in some cases, moisture monitoring systems. The EPA will adjust the ECMPS monitoring plan format to accommodate this same type of information for Hg, HCl, and HF CEMS, with the addition of a few codes for the new parameters.

The second type of data collected through ECMPS is certification and QA test data. These data include data from linearity checks, RATAs, cycle time tests, 7-day calibration error tests, and a number of other QA tests that are required to validate the emissions data. You may submit the results of these tests to the EPA as soon as you obtain the results, with one notable exception. Daily calibration error tests are not treated as individual QA tests, due to the large number of records generated each quarter. Rather, these tests must be included in the quarterly electronic reports, along with the hourly emissions data. The ECMPS system is set up to receive and process certification and QA data from SO_2, CO_2, O_2, flow rate, and moisture monitoring systems that are installed, certified, maintained, operated, and quality-assured according to 40 CFR part 75. EGUs routinely submit these data to the EPA under the ARP and other emissions trading programs.

To accommodate the certification and QA tests for Hg CEMS, other CEMS, and sorbent trap monitoring systems, the structure and functionality of ECMPS needs relatively few changes, because most of the tests are the same as those required for other gas monitors. For reporting Hg, HCl, SO_2, and HF CEMS data under this rule, we are disabling ECMPS' 40 CFR part 75 bias test (which is required for certain types of monitors under the EPA's SO_2 and NO_X emissions trading programs). The bias adjustment of the data from these monitors is unnecessary for compliance with the rule.

The third type of data collected through ECMPS is the hourly emissions data, which, as previously noted, is reported on a quarterly schedule. You must submit reports within 30 days after the end of each calendar quarter. The emissions data format requires hourly reporting of all measured and calculated emissions values, in a standardized electronic format. You must report direct measurements made with CEMS, such as gas concentrations, in a Monitor Hourly Value (MHV) record. A typical MHV record for gas concentration includes data fields for:

(1) The parameter monitored (*e.g.*, SO_2);

(2) The unadjusted and bias-adjusted hourly concentration values (note that if bias adjustment is not required, only the unadjusted hourly value is reported);

(3) The source of the data, *i.e.*, a code indicating either that each reported hourly concentration is a quality assured value from a primary or backup monitor, or that quality-assured data were not obtained for the hour; and

(4) The percent monitor availability (PMA), which is updated hour-by-hour. This generic record structure could easily accommodate hourly average measurements from CEMS used under this rule.

The ECMPS reporting structure is quite flexible, which makes it useful for assessing compliance with various emission limits. The Derived Hourly Value (DHV) record allows calculations of a wide variety of quantities from the reported hourly emissions data. For instance, if an emission limit is expressed in units of lb/MMBtu, the DHV record can be used to report hourly pollutant concentration values in these units of measure, since the lb/MMBtu values can be derived from the hourly pollutant and diluent gas (CO_2 or O_2) concentrations reported in the MHV records. The ECMPS can also accommodate multiple DHV records for a given hour in which more than one derived value is required to be reported. The system will support reporting hourly data in the units of the emission standards (*e.g.*, lb/MMBtu, lb/TBtu, lb/GWh, etc.) when hourly Hg concentration data are reported through ECMPS using the DHV record, in conjunction with the appropriate equations and auxiliary information such as heat input and electrical load (all of which are reported hourly in the emissions reports).

One change in this rule from standard 40 CFR part 75 emissions data reporting is elimination of the requirement to provide substitute data calculations within ECMPS. The ARP and other emissions trading programs that report emissions data to the EPA using 40 CFR part 75 require provision of a complete data record. Emissions data are required to be reported for every unit operating hour. When CEMS are out of service, substitute data must be reported to fill in the gaps. However, for the purposes of compliance with a NESHAP, reporting substitute data during monitor outages is not necessary, as quantification of total mass emissions is not the focus of the rule. Hours when a monitoring system is out of service would be counted as hours of monitor down-time and may be a deviation from the monitoring requirements of this rule unless the rule provides an exception, as it does for routine quality control and maintenance activities.

In contrast to the CEMS-related data that would be submitted through ECMPS, you must submit reports of performance tests and PM CPMS data to EPA's WebFIRE database by using CEDRI that is accessed through EPA's

CDX (*www.epa.gov/cdx*). You must submit performance test data in the file format generated through use of EPA's ERT (see *http://www.epa.gov/ttn/chief/ert/index.html*) within 60 days of performance test completion. Electronic data submittal requirements are described in section V.H. of this preamble.

Other notifications and reports not currently accepted by the electronic reporting system will be submitted in hardcopy form at this time.

VI. Summary of Significant Changes Since Proposal

The previous section described the requirements that EPA is finalizing in this rule. This section will discuss in greater detail the key changes EPA is making from the proposed. These changes result from EPA's review of the additional data and information provided to us and our consideration of the many substantive and thoughtful comments submitted on the proposal. While our approach and methodology to establishing the standards remain the same, the changes make the final rule more flexible and cost-effective, reduce reliability concerns and improve clarity, while fully preserving, or improving, the public health and environmental protection required by the CAA.

A. Applicability

Since proposal, the EPA has made certain changes to the applicability provisions of the final rule to provide clarity. These changes do not change the universe of sources subject to the rule.

The EPA is revising a number of the proposed definitions and adding a definition for "natural gas-fired electric utility steam generating unit" in the final rule to provide clarity to the regulated community concerning the standards applicable to coal- and oil-fired EGUs.

In the proposed rule, the EPA defined "[e]lectric utility steam generating unit" consistent with the CAA section 112(a)(8) definition:

> A fossil fuel-fired combustion unit of more than 25 megawatts electric (MWe) that serves a generator that produces electricity for sale. A fossil fuel-fired unit that cogenerates steam and electricity and supplies more than one-third of its potential electric output capacity and more than 25 MWe output to any utility power distribution system for sale is considered an electric utility steam generating unit.

40 CFR 63.10042.

We also indicated how we would determine whether units were coal-fired or oil-fired fired EGUs: "If an EGU burns coal (either as a primary fuel or as a supplementary fuel), or any combination of coal with another fuel (except solid waste as noted below), the unit is considered to be coal fired under this proposed rule. If a unit is not a coal-fired unit and burns only oil, or oil in combination with another fuel other than coal (except as noted below), the unit is considered to be oil fired under this proposed rule." 76 FR 25020.

We proposed a definition for the term "fossil fuel-fired" because that term was not defined in the statute and we wanted to clarify the level of fossil fuel combustion necessary to satisfy the CAA section 112(a)(8) definition of EGU. The definition focused on coal and oil combustion because the EPA was only regulating coal- and oil-fired EGUs in this final rule. The proposed definition contained two primary elements: (1) the unit must be capable of combusting sufficient amounts of coal or oil to generate the equivalent of 25 megawatts electrical output; and (2) the unit must have fired coal or oil for more than 10.0 percent of the average annual heat input during the previous 3 calendar years or for more than 15.0 percent of the annual heat input during any one of those calendar years. 76 FR 25025. We further stated that for a unit to be "capable of combusting" coal or oil the unit must have a permit that authorized the combustion of coal or oil and also have the appropriate fuel handling facilities on-site. *Id.*

As explained in the proposed rule, natural gas-fired EGUs were not included in the December 2000 listing so such units that otherwise met the CAA section 112(a)(8) definition of EGU because of natural gas combustion are not subject to the final rule. In the proposed rule, we stated that an EGU that "combusts natural gas exclusively or natural gas in combination with another fuel where the natural gas constitutes 90 percent or more of the average annual heat input during the previous 3 calendar years or 85.0 percent or more of the annual heat input during any one of those calendar years" was not subject to the rule. *Id.* The references to 90 percent natural gas combustion over 3 years and 85 percent natural gas combustion in any one year were included to align with the definitions of "fossil fuel-fired" so that it would be clear that units combusting primarily natural gas would not be considered coal-fired, oil-fired, or IGCC EGUs if they burned 10 percent or less of coal, oil, or synthetic gas derived from coal or solid oil over 3 years or 15 percent or less of such fuels in any one year. We did not intend to suggest that to be considered a fossil fuel-fired EGU a natural gas-fired unit that is not a coal-fired or oil-fired EGU would have to combust natural gas that exceeded the 10 percent/15 percent thresholds set forth in the proposed rule. In fact, in 40 CFR 63.9983 of the proposed rule, we stated that "[a]ny EGU that is not a coal- or oil-fired EGU and combusts natural gas more than 10.0 percent of the average annual heat input during the previous 3 calendar years or for more than 15.0 percent of the annual heat input during any one of those calendar years" is not subject to this subpart.

We further explained that the percentages included in the definition of "fossil fuel-fired" would prevent units that primarily combusted fuels other than fossil fuels from being subjected to the final rule:

> Units that do not meet the definition of fossil-fuel fired would, in most cases, be considered IB units subject to one of the Boiler NESHAP. Thus, for example, a biomass-fired EGU, regardless of size, that utilizes fossil fuels for startup and flame stabilization purposes only (*i.e.*, less than or equal to 250 MMBtu/hr and used less than 10.0 percent of the average annual heat input during the previous 3 calendar years or less than 15.0 percent of the annual heat input during any one of those calendar years) is not considered to be a fossil fuel-fired EGU under this proposed rule. The EPA has based its threshold value on the definition of "oil-fired" in the ARP found at 40 CFR 72.2. As EPA has no data on such use for (*e.g.*) biomass co-fired EGUs because their use has not yet become commonplace, we believe this definition also accounts for the use of fossil fuels for flame stabilization use without inappropriately subjecting such units to this proposed rule. *Id.*

Thus, in the proposed rule, we intended to create thresholds to determine when a unit is fossil fuel-fired and for which fossil fuel the unit is fossil fuel-fired. We intended to include a unit combusting more than the defined amount of coal in one of the coal-fired EGU subcategories. If a unit is not coal-fired and it is combusting more than the defined amount of oil, we intended to include the unit in one of the oil-fired EGU subcategories. We also intended to make clear that EGUs that are neither coal-fired nor oil-fired but combust more than the defined amount of natural gas are natural gas-fired EGUs not subject to the final standards. However, the definitions, as proposed, were not sufficiently descriptive.

For example, we included a definition for "coal-fired electric utility steam generating unit" that did not include the requirement that the unit must combust coal for at least 10 percent of the heat input over 3 years or 15 percent of the heat input in any one year. Instead, in the proposed rule we indicated that a unit was coal-fired if it burned coal in any amount. We did not intend to

define a unit as coal-fired if it burned coal that accounted for 10 percent or less over 3 years or 15 percent of less in any one year, as that would be inconsistent with the definition of fossil fuel-fired and the definitions for the oil-fired EGU subcategories. Under the proposed rule construct, a unit that combusts mostly biomass and less than 10 percent coal over 3 years would not be a coal-fired EGU because it would not meet the "fossil fuel-fired" definition. But a unit burning mostly petroleum coke and less than 10 percent coal over 3 years might be considered a coal-fired EGU because it would meet the definition of "fossil fuel-fired" and be burning some coal, even though that level of coal combustion alone would not be sufficient to make the unit "fossil fuel-fired" for coal. That result is at odds with our intent. The same would hold true for an EGU that combusts mostly natural gas and less than 10 percent synthetic gas derived from coal over a 3-year period. Our proposal preamble makes clear that we did not intend this result because we specifically stated that units burning 90 percent or more natural gas over a 3-year period would be considered natural-gas fired EGUs. 76 FR 25025.

In addition, we proposed to define "[u]nit designed to burn solid oil fuel subcategory" to include any EGU that burned a solid fuel derived from oil for more than 10.0 percent of the average annual heat input during the previous 3 calendar years or for more than 15.0 percent of the annual heat input during any one of those calendar years, either alone or in combination with other fuels. We also included the 10 percent/15 percent thresholds in the definition for the liquid oil subcategory, but, as stated above, we did not include the thresholds in the definition of "coal-fired" EGU. Therefore, there would be some confusion for a source that blended coal with solid oil derived fuel (*e.g.*, petroleum coke). For example, the owner or operator of an EGU that burned sufficient solid oil-derived fuel that accounted for 80 percent of the heat input in a given year and the remainder of the fuel was coal would not be sure which standard applied because the definitions in the proposed rule were internally inconsistent.

For these reasons, we are revising the definitions for "coal-fired electric utility steam generating unit," "integrated gasification combined cycle electric utility steam generating unit," and "oil-fired electric utility steam generating unit," and we are adding a definition of "natural-gas fired electric utility steam generating unit" as set out in 40 CFR 63.10042.

In addition to these changes, we are revising the definition of "fossil fuel-fired" based on comments. We are revising the definition to remove the heat input equivalent of 25 MW because commenters noted that the equivalency used (taken from 40 CFR part 60, subpart Da) could not be applied consistently because of differing boiler efficiencies. Commenters noted that owners/operators were familiar with the use of the "MW" term for the boilers and boilers include nameplate capacities that are readily identifiable.

We are also including a revision to the definition so that the fossil fuel combustion thresholds of 10 percent over 3 consecutive years and 15 percent in one year are evaluated after the applicable compliance date of the final rule on a rolling basis. Commenters correctly noted that some existing coal- and oil-fired EGUs will convert their units to alternative fuels (*e.g.*, natural gas or biomass) and if the definition were finalized as proposed such units could be improperly subjected to the final standards.

The new definition is set out in 40 CFR 63.10042.

For clarity, we are also removing the definition of "[u]nit designed to burn liquid oil fuel subcategory," revising the definition of "[u]nit designed to burn solid oil fuel subcategory," adding definitions for the continental and non-continental liquid oil-fired EGU subcategories, and adding a definition of a limited-use liquid oil-fired EGU as set out in 40 CFR 63.10042.

In the proposed rule, we stated that we believed EGUs may at times not meet the definition of an EGU subject to this subpart. For example, we explained that there may be some cogeneration units that are determined to be covered under the Boiler NESHAP. Such unit(s) may make a decision to increase the proportion of production output being supplied to the electric utility grid, thus causing the unit(s) to meet the EGU cogeneration criteria (*i.e.*, greater than one-third of its potential output capacity and greater than 25 MW). In the preamble to the proposed rule, we indicated that a unit subject to one of the Boiler NESHAP that increases its electricity output and meets the definition of an EGU would be subject to the EGU NESHAP for the 6-month period after the unit meets the EGU definition.[310] 76 FR 25026. Assuming the EGU did not meet the definition of an EGU following that initial occurrence, at the end of the 6-month period it would revert back to being subject to the Boiler NESHAP, or other applicable standard. We solicited comment on the extent to which situations like this might occur, how the EPA should address situations where units change applicability, and whether we should include provisions similar to those included in the final CISWI (40 CFR 60.2145) to address such situations. *Id.*

Several commenters asked the Agency to include provisions in the final rule that would address situations like the ones described in the preamble to the proposed rule. Because applicability to the final rule is based in part on the statutory definition of an EGU is CAA section 112(a)(8), similar to the situation with units combusting solid waste under CAA section 129(g)(1) (*e.g.*, CISWI Rule), we are adopting provisions in the final rule that are based on the fuel switching provisions of the final CISWI Rule (*See* Final CISWI Rule, 40 CFR 60.2145). For example, a cogeneration unit that did not historically provide more than one third of its potential electrical output capacity to a power distribution system could change its output and provide more than 25 megawatts electrical output to any power distribution system for sale. Such units would be subject to MATS. If the cogeneration unit later reduced its output such that it no longer met the definition of an EGU, that source would nevertheless remain subject to MATS for at least 6 months from the date that the unit first qualified as an EGU.

In addition, we are finalizing a provision whereby you may opt to remain subject to the provisions of this final rule, unless you combust solid waste, in which case you are a solid waste incineration unit subject to standards under CAA section 129 (*e.g.*, 40 CFR part 60, subpart CCCC (New Source Performance Standards (NSPS) for Commercial and Industrial Solid Waste Incineration Units), or subpart DDDD (Emissions Guidelines (EG) for Existing Commercial and Industrial Solid Waste Incineration Units)). We believe the provision to opt to remain subject to this final rule will ameliorate conditions where EGUs may potentially move between NESHAP on a relatively frequent basis. Notwithstanding the provisions of this final rule, an EGU that starts combusting solid waste is subject to standards under CAA section 129, and the unit remains subject to those standards until the unit no longer meets the definition of a solid waste incineration unit consistent with the provisions of the applicable CAA section 129 standards.

[310] Although we clearly stated the intent to require sources to comply for 6 months after meeting the definition of an EGU, we inadvertently failed to include the provision in the proposed rule.

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The changes to the definitions described above provide clarity to sources, permitting agencies, and the public about the applicability of the rule and help ensure that sources are appropriately covered by the regulation.

B. Subcategories

In this final rule, the EPA is adding subcategories for limited-use oil-fired units and non-continental oil-fired units and revising the definitions for the coal-fired EGU subcategories.

The proposed rule subcategorized EGUs burning coal into two subcategories: EGUs designed for coal ≥8,300 Btu/lb and EGUs designed for virgin coal <8,300 Btu/lb (low rank virgin coal). We received a number of comments indicating that the definition of the low rank virgin coal subcategory was technically deficient.

Under CAA section 112(d)(1), the Administrator has the discretion to "* * * distinguish among classes, types, and sizes of sources within a category or subcategory in establishing * * *" standards. The EPA maintains that, normally, any basis for subcategorization (*i.e.*, class, type, or size) must be related to an effect on HAP emissions that is due to the difference in class, type, or size of the units. *See* 76 FR 25036–25037. The EPA believes it is not reasonable to exercise our discretion without such a difference because if sources can achieve the same level of emissions reductions notwithstanding a difference in class, type, or size, the purposes of CAA section 112 are better served by requiring a similar level of control for all such units in the category or subcategory. *See Lignite Energy Council* v. *EPA*, 198 F. 3d 930, 933 (D.C. Cir. 1999) ("EPA is not required by law to subcategorize—section 111[b][2] merely states that 'the Administrator *may* distinguish among classes, types, and sizes within categories of new sources'" (emphasis original)); *see* also CAA section 112(d)(1) (containing almost identical language to CAA section 111, CAA section 112(d)(1) provides that "the Administrator may distinguish among classes, types, and sizes of sources within a category or subcategory in establishing [ ] standards * * *"). Even if we determine that emissions characteristics are different for units that differ in class, type, or size, the Agency may still decline to subcategorize if there are compelling policy justifications that suggest subcategorization is not appropriate. *Id.*

When developing the proposed rule, we examined the EGUs in the top performing 12 percent of sources for Hg emissions. We determined that:

There were no EGUs designed to burn a nonagglomerating virgin coal having a calorific value (moist, mineral matter-free basis) of 19,305 kJ/kg (8,300 Btu/lb) or less in an EGU with a height-to-depth ratio of 3.82 or greater among the top performing 12 percent of sources for Hg emissions, indicating a difference in the emissions for this HAP from these types of units. The boiler of a coal-fired EGU designed to burn coal with that heat value is bigger than a boiler designed to burn coals with higher heat values to account for the larger volume of coal that must be combusted to generate the desired level of electricity. Because the emissions of Hg are different between these two subcategories, we are proposing to establish different Hg emission limits for the two coal-fired subcategories. For all other HAP from these two subcategories of coal-fired units, the data did not show any difference in the level of the HAP emissions and, therefore, we have determined that it is not reasonable to establish separate emissions limits for the other HAP. 76 FR 25036–67.

Based on this determination, we proposed to establish two subcategories with separate Hg limits. Comments on the proposed rule indicate that we correctly identified the EGUs that should be included in each subcategory, but the comments also demonstrated that we made certain incorrect conclusions that require us to revise the definitions of our coal-fired EGU subcategories. The revised definitions ensure that the EGUs we identified at proposal as having different Hg emissions remain in one subcategory.

As stated above, we believed at proposal that the boiler size was the cause of the different Hg emissions characteristics that led us to propose subcategorization, but many commenters indicated that it was not the boiler size but the fact that the EGUs burned a nonagglomerating virgin coal having a calorific value (moist, mineral matter-free basis) of less than 19,305 kJ/kg (8,300 Btu/lb) (low rank virgin coal) that causes the disparity in Hg emissions. Several commenters indicated that their EGUs were designed to burn and burned low rank virgin coal but the units did not meet the height-to-depth ratio that EPA proposed. For example, the height-to-depth ratio of certain EGUs in this subcategory is in fact 3.5, not 3.82. Further, there are other EGUs in this subcategory that are circulating fluidized bed (CFB) combustion units which do not meet the height-to-depth ratio parameters in the proposed rule, nor are they anything like the pulverized coal (PC) EGUs we initially identified as having the 3.82 height-to-depth ratio.

In addition to the comments concerning EGUs firing this coal, we received comments from at least two commenters indicating that the EPA should clarify in which subcategory a unit belongs when it does not burn low rank virgin coal but is designed to combust low rank virgin coal and has a height-to-depth ratio of greater than 3.82. Commenters also indicated that CFB units that are burning coal-refuse [311] or other nonagglomerating virgin coal having a calorific value (moist, mineral matter-free basis) of 19,305 kJ/kg (8,300 Btu/lb) or greater are "designed to burn" any type of coal. Owners of CFB units that are not firing low rank virgin coal asked which subcategory they belong to based on their ability to burn any type of coal (including low rank virgin coal) without modification. These commenters also indicated that some coal refuse that is combusted has a heating value less than 8,300 Btu/lb but is not "virgin coal." It was unclear to which subcategory they belonged since the proposed rule did not in fact require the unit to burn any specific coal, instead only requiring the unit be "designed" to burn lower Btu coal.

Based on the comments received, we reevaluated the subcategory definitions because we were concerned that the definitions we proposed would improperly categorize a number of the EGUs in both subcategories. We concluded that we should not maintain the proposed definition for "[u]nits designed for coal <8,300 Btu/lb" and exclude the CFB units and PC EGUs with a height-to-depth ratio less than 3.82 that combusted low rank virgin coal.

We were equally concerned that the subcategory definitions not be revised in a manner that would move EGUs that we believed the data show could comply with a more stringent standard into a subcategory with a less stringent standard because, aside from the type of EGUs we identified, all other classes, types, and sizes of EGUs were represented among the top performing 12 percent for Hg in the ≥8,300 Btu/lb subcategory. We were particularly concerned about the CFB units because other CFB units are well represented among the best performing EGUs for Hg in the ≥8,300 Btu/lb subcategory, but the CFB units burning low rank virgin coal are not achieving the same levels of Hg emissions control. Including the best performing CFB units from the other subcategory in the low rank virgin coal subcategory would likely lead to a Hg standard as stringent as the standard for

[311] It is our understanding that no unit combusts coal-refuse from nonagglomerating virgin coal having a calorific value (moist, mineral matter-free basis) of less than 19,305 kJ/kg (8,300 Btu/lb).

EGUs in the ≥8,300 Btu/lb subcategory because the CFB units from the other subcategory would be used to establish the floor. We believe that result would be inconsistent with the intent of the proposed rule. We were also concerned about the information that some EGUs that fired low rank virgin coal had a height-to-depth ratio of 3.5, not 3.82, and that some EGUs that fired other ranks of coal had a height-to-depth ratio greater than 3.82. For these reasons, we did not revise the definition to include CFB units and PC EGUs with a height-to-depth ratio greater than 3.5.

After fully considering the available information, including the comments received, we have concluded that it is appropriate to continue to base the subcategory definitions, at least in part, on whether the EGUs were designed to burn and, in fact, did burn low rank-virgin coal, but that it is not appropriate to continue to use the height-to-depth ratio criteria because that approach would potentially exclude EGUs we identified as having different Hg emission characteristics and include EGUs that did not have different emissions characteristics. We recognize that some commenters have taken the position that it is unlawful to subcategorize based on factors such as fuel type but nothing in the statute prohibits such an approach and the case law supports this approach to the extent courts have considered subcategorization based on such factors. *See Sierra Club* v. *Costle,* 657 F. 2d 298, 318–19 (D.C. Cir. 1981) (differing pollutant content of input material can justify a different standard based on subcategorization authority to "distinguish among classes, types and sizes within categories of new sources"). Furthermore, we believe had Congress intended to prohibit the EPA from subcategorizing based on an EGU being designed to use and using a certain material input (*e.g.,* fuel) it would have clearly stated such intent in the CAA. However, we believe the Agency could decline to exercise its discretion to subcategorize even if the potential result would be the prohibition of the use of some materials if the circumstances warranted. We note that even if we did not subcategorize on the final basis selected, the Hg emissions standard of 1.2E0 lb/Tbtu for the "unit designed for coal ≥8,300 Btu/lb" would remain the same.

We considered basing the subcategory solely on an EGU being designed to burn and burning low rank virgin coal. We decided not to do so because we were concerned that such a definition would allow sources to potentially meet the definition by combusting very small amounts of low rank virgin coal. For example, an EGU on the east coast (or any other region) that was not designed to burn and did not routinely burn low rank virgin coal could import one truck full of low rank virgin coal and burn a very small quantity of it periodically to meet the subcategory definition. To avoid creating this potential loophole, we considered other characteristics that would distinguish EGUs combusting low rank virgin coal.

We determined that these EGUs are universally constructed "at or near" a mine containing low rank virgin coal because it is not cost-effective to transport large quantities of such fuel long distances. Furthermore, we believe that this subcategory of EGUs are almost always built at a mine and limited transportation of the coal is only required as the mine face moves over the course of time. Many such EGUs construct dedicated rail lines, private roads, or conveyor systems to transport the coal to the EGU as the mine face moves. We obtained information from data acquired to develop the CSAPR indicating that the longest distance any EGU firing low rank virgin coal transports that coal is 40 miles. We believe that this distance is near the outer limits for the transport of such coal, but, even for those EGUs, the EGUs were constructed closer to a now idle mine or closer to the working face of a mine that has now expanded away from the EGU site. For these reasons, we are including a requirement that the unit be constructed and operated at or near a mine containing the low rank virgin coal it burns.

We are revising the coal-fired EGU subcategory definitions as set out in 40 CFR 63.10042.

We believe the revised subcategory definitions are reasonable for all the reasons set forth above. The revised definitions maintain the EGUs we identified as having different Hg emissions characteristics in one subcategory and the definitions prevent other EGUs that are not firing low rank virgin coal from being required to comply only with the less stringent Hg emission standard.

As discussed in response to comments, we do not believe that additional subcategorization of other coal-fired EGUs is reasonable or appropriate. All other coal-fired EGUs that are not designed to burn and are burning low rank virgin coal are represented among the best performing sources for Hg, such that no argument exists to support that the Hg emissions from those EGUs are different. In any case, even if emissions are somewhat different as some commenters suggest, we would decline to exercise our discretion because the data demonstrate that the best performing EGUs designed to burn and burning all other ranks of coal are able to achieve the MACT level of control using currently available controls and other HAP emission reduction mechanisms (*e.g.,* coal washing) for the ≥8,300 Btu/lb subcategory.

A second issue related to subcategorization concerns non-continental liquid oil-fired EGUs. At proposal, the EPA did not have sufficient emissions data from non-continental liquid oil-fired EGUs upon which to base a subcategory and took comment on the issue. The data have since been provided in response to the ICR and we received comments suggesting that a non-continental subcategory is appropriate based on the location of such units, the limited availability of alternative fuel sources, and the fact that the emissions characteristics of such units are distinct from continental liquid oil-fired EGUs. The EPA has evaluated the data and comments and we agree that a subcategory is warranted based for the reasons suggested by the commenters. Therefore, the Agency is finalizing the liquid oil-fired EGU subcategories of "continental" and "non-continental."

Lastly, the EPA did not have sufficient information on limited-use liquid oil-fired EGUs upon which to base a subcategory at proposal because some sources required to test under the ICR did not submit the data until after proposal. We took comment on whether a limited-use subcategory was warranted. Commenters indicated that their units were a different class and type of units because many of them were only called to service to address reliability issues associated with, for example, natural gas curtailments. The commenters further indicated that their units are different because of the generally infrequent use and the sporadic, and at times frequent, start-up and shutdown periods (*e.g.,* they are often only required to run for a couple of hours). These factors would lead to differences in the emissions characteristics for these units such that a numeric standard based on base load units would not likely be achievable during the very limited times that these limited use oil-fired units operate. Based on comments received and our own analysis, we are finalizing a subcategory for limited-use liquid oil-fired EGUs as discussed further elsewhere in this preamble.

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C. Emission Limits

The proposed rule included numerical emission limits for PM, Hg, HCl, HF, SO_2, total HAP metals, and individual HAP metals, depending on the subcategory and specific situation. These proposed limits resulted from calculations of MACT floors using information and data available to the Agency prior to proposal, as required by CAA section 112. Based on information and data received during the comment period, we have made data and calculation corrections where necessary and then re-ranked the best performing units in the MACT floor pools. Based on the new ranking, a limited number of the emission limits in the final rule have changed from those proposed.

In addition to adjustments to the emission limits themselves, we are finalizing several other changes to the emission standards that will simplify and improve compliance for sources without compromising the toxics reductions achieved. One key change, as discussed elsewhere in this notice, is that we have changed the surrogate for non-mercury metallic HAP from total particulate matter (PM) to filterable PM for coal-fired and solid oil-derived EGUs. This change is based on information provided in comments and our own conclusion that measurement of filterable PM provided assurance of equivalent HAP emissions control. Most of the non-mercury metal HAP, for which PM is a surrogate, are filterable PM and the one that is not (Se) is well controlled by the limit on acid gases. Using filterable PM as the surrogate will allow us to use continuous PM monitoring systems, which measure filterable (but not total) PM, thereby providing a more continuous measure of compliance.

For liquid oil-fired EGUs, based on comments received and corrections made to the data submitted, we have added a filterable PM limit in the final rule as an alternative equivalent standard for the total metal-HAP limit in the proposed rule. In addition, as discussed elsewhere in this notice, we have added measurement of the moisture content of the oil (with a 1 percent limit) as an alternate compliance assurance measure for liquid oil-fired EGUs for determining compliance with the HCl and HF limits. Direct measurement of HCl and HF remains a compliance demonstration method in the final rule. Finally, as discussed in section VI.D of this notice, the final work practice standard consisting of burner tune-ups, much like those required for organic HAP control, for those limited-use liquid oil-fired EGUs whose annual capacity factor is less than 8 percent.

D. Work Practice Standards for Organic HAP Emissions

As noted earlier in section V.D., the final rule includes a work practice standard for organic HAP, including dioxins and furans, applicable to all EGUs. As noted in section V.D. above, the majority of emissions of these pollutants are below the detection levels of EPA test methods and, therefore, are impractical to measure. The work practice standard, described below, is a practical approach to ensuring that equipment is maintained and run so as to minimize emissions of dioxins and furans, and we expect it to be more effective than establishing a numeric standard that cannot reliably be measured or monitored. The work practice also applies to the limited-use liquid oil-fired subcategory included in the final rule.

The work practice involves maintaining and inspecting the burners and associated combustion controls (as applicable), tuning the specific burner type to optimize combustion, obtaining and recording CO and NO_X values before and after the burner adjustments, keeping records of activity and measurements, and submitting a report for each tune-up conducted. In Table 3 of the final regulation, we have clarified that this refers to performance tune-ups, not tests, and have addressed the frequency requirement as discussed in response to comments about the appropriateness of the 18-month frequency. The provisions of 40 CFR 63.10006(h)(i) refer to 40 CFR 63.10021(e) for the specific steps required to be part of the periodic tune-up. We have also adjusted the language in the final rule to recognize the value of automated boiler optimization tools such as neural network systems.

Under the final rule, the tune-up must be conducted at each planned major outage and in no event less frequently than every 36 calendar months, with an exception that if the unit employs a neural-network system for combustion optimization during hours of normal unit operation, the required frequency is a minimum of once every 4 years (48 calendar months). Initial compliance with the work practice standard of maintaining burners must occur within 180 days of the compliance date of the rule. The initial compliance demonstration for the work practice standard of conducting a tune-up may occur prior to the compliance date of the rule, but must occur no later than 42 months (36 months plus 180 days) from the compliance date of the rule or, in the case of units employing neural network combustion controls, 54 months (48 months plus 180 days). If the tune-up occurs prior to the compliance date of the rule, you must maintain adequate records to show that the tune-up met the requirements of this standard.

We have made a number of specific changes to address what to do for repairs that may require longer term corrective actions, additional methods for evaluating combustion effectiveness, and clarification on procedures for recording CO and NO_X information. There were specific comments that opposed the reference to manufacturer specifications, if available. We retained this language in the final rule, but note that these specifications apply only to the extent applicable. Specifically, if manufacturer specifications only address equipment or conditions that are no longer present given current boiler operations, then those specifications are not applicable and other combustion engineering best practice procedures for that burner type would apply. We have also clarified that portable emission monitoring equipment may be used to collect the required emissions optimization data regarding pre- and post-tune-up CO and NO_X emission levels.

E. Requirements During Startup, Shutdown, and Malfunction

We proposed numerical emission standards that would apply at all times, including during periods of startup, shutdown, and malfunction. Although at proposal we stated that we were not setting a different standard for startup and shutdown, we did propose different standards for startup and shutdown by our inclusion of the default values described below, which applied only during startup and shutdown. Specifically, we stated:

> To appropriately determine emissions during startup and shutdown and account for those emissions in assessing compliance with the proposed emission standards, we propose use of a default diluent value of 10.0 percent O_2 or the corresponding fuel specific CO_2 concentration for calculating emissions in units of lb/MMBtu or lb/TBtu during startup or shutdown periods. For calculating emissions in units of lb/MWh or lb/GWh, we propose source owners use an electrical production rate of 5 percent of rated capacity during periods of startup or shutdown. We recognize that there are other approaches for determining emissions during periods of startup and shutdown, and we request comment on those approaches. We further solicit comment on the proposed approach described above and whether the values we are proposing are appropriate.

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We proposed application of the respective emission limits during periods of startup and shutdown and use of default values to calculate the emission limits. The standards that apply at all times other than startup and shutdown are production-based limits, which is why we proposed the default values. The default values were meant to account for the fact that during startup and shutdown events, production (in this case the generation of electricity) is by definition nonexistent. Thus, in effect, we proposed a separate standard to apply during startup and shutdown.

We received a variety of comments on the proposed standards that would apply during startup and shutdown. Many commenters pointed to the lack of data in the record concerning emissions that occur during periods of startup and shutdown. They further asserted that emissions during these periods can be highly variable in light of the sequence of events that occurs during the startup and shutdown of an EGU. Although a number of commenters supported the use of the diluent factor approach, including the default 5 percent of rated capacity, during startup/shutdown periods, other commenters questioned the feasibility of collecting additional data during such periods and had concerns regarding the reliability of measurements obtained from EGUs during such periods.

In response to the Agency's ICR to the utility industry, seven owners or operators indicated that they provided startup and shutdown data for their EGUs. These data were submitted in response to the requirement in the ICR to provide all available data from the 5 years prior to the date the ICR was issued. Of these data, there were almost no HAP data for startup and shutdown periods and almost all of the data failed to meet our data quality requirements.[312] Thus, we do not have sufficient data on emissions that occur during startup and shutdown on which to set emission standards. We are therefore establishing work practice standards rather than numeric emissions standards for periods of startup and shutdown in the final rule. Before we describe those work practices, we first address what constitutes startup and shutdown.

Several commenters had an expansive view of what constitutes startup and shutdown. We disagree with these commenters that asserted that periods of "load swings" should be considered "startup" or "shutdown," as they are generally routine, normal operations with production (*i.e.,* generation of electricity) taking place. We maintain that the standards as promulgated account for any variability in emissions that may occur during these periods over a 30-day averaging period, and commenters have provided no data that cause us to doubt that determination. We have included definitions of startup and shutdown in the final rule that are consistent with the definitions in the proposed rule. At proposal, we defined startup as the setting in operation of an affected source or portion of an affected source for any purpose, and shutdown as the cessation of operation of an affected source or portion of an affected source for any purpose.

Commenters sought more clarity regarding the meaning of these terms as applied to EGUs, so we are revising the definitions in the final rule as set out in 40 CFR 63.10042.

These interpretations are tailored for EGUs and are consistent with the definitions of "startup" and "shutdown" contained in the 40 CFR part 63, subpart A General Provisions. We believe these revised definitions address the comments and are rational based on the fact that EGUs function to provide electricity primarily for sale to the grid but also at times for use on-site; therefore, EGUs should be considered to be operating normally at all times electricity is generated. We further believe these revised definitions address what some commenters describe as "warm" and "hot" startups as long as the EGU is shutdown (*i.e.,* no fuel fired and no electricity generation) prior to the "warm" or "hot" startup period.

As for the work practices, in this final rule, the EPA is requiring sources to operate using either natural gas or distillate oil for ignition during startup. The EPA also is requiring sources to vent emissions to the main stack(s) and operate all control devices necessary to meet the normal operating standards under this final rule (with the exception of dry scrubbers and SCRs) when coal, solid oil-derived fuel, or residual oil is fired in the boiler during startup or shutdown. It is the responsibility of the operators of EGUs to start their dry scrubber and SCR systems appropriately to comply with relevant standards applicable during normal operation.

The EPA carefully considered fuels and potential operational constraints of air pollution control devices (APCDs) when designing its work practices for periods of startup and shutdown. The EPA notes that there is no technical barrier to burning natural gas or distillate oil for longer portions of startup or shutdown periods, if needed, at a boiler, and the HAP emission reduction benefits warrant additional utilization of such fuels until the temperature and stack emissions pressure is sufficient to engage the APCDs. The EPA is aware that SCR systems with ammonia injection need to be operated within a prescribed and relatively narrow temperature window to provide NO_X reductions. Further, the EPA is aware that dry scrubbers also need to be operated close to flue gas saturation temperature. Because these devices have specific temperature requirements for proper operation, the EPA notes in its work practices that it is the responsibility of the operators of EGUs to start their SCR and dry scrubber systems appropriately to comply with relevant standards applicable during normal operation.

Some commenters have asserted that firing of fuel oil during periods of startup and shutdown constrains operation of PM controls (ESPs and baghouses) because under cooler conditions, acids and tars can condense on surfaces in these controls. The commenters assert that such condensation can cause detrimental impacts on hardware and operation of these controls, and could cause safety concerns. The EPA understands that concerns with acidic and tarry deposits are related to firing of heavy (residual) oil and not distillate oil. Accordingly, with residual fuel oil firing, site-specific flue gas temperature and oxygen (O_2) concentration thresholds may be applicable to minimize condensation of acids and tars and thereby minimize any potential for detrimental impacts on hardware and any safety concerns.

[312] In response to the ICR, we also received SO_2 CEMS data and the Agency had additional SO_2 CEMS data available through the CAMD ARP database. We are not able to identify specific periods of start-up and shutdown in either the ICR CEMS data or the CAMD ARP data, and the ICR respondents do not indicate that the ICR data includes periods of startup and shutdown. We set the emission limits for SO_2 and HCl using the data provided to the EPA from the 2010 ICR, not the CAMD data, since those data were taken concurrently under the same specified operating conditions using the same fuel. We used the SO_2 CEMS data that was submitted in response to the ICR by converting it to single point data to correlate to the data from units that did not provide CEMS data from the relevant testing period. The emissions limits for the NESHAP incorporated variability by applying the 99 percent UPL to the average emissions developed from the stack test data and SO_2 CEMS data that was converted to stack test data. Thus, we did not have data on which to establish an SO_2 standard during periods of startup and shutdown and the numeric standards do not apply to those periods in the final rule. In contrast, the NSPS for SO_2 is applicable during periods of startup and shutdown since the long term CAMD ARP CEMS data were used to determine the average performance of the best demonstrated technology. Those long term data were assumed to incorporate process variability including that associated with fuel and process/operational changes and periods of startup and shutdown.

However, the EPA notes that its work practice requirements provide flexibility to the operator to take appropriate site-specific remedial measures, if needed. The EPA further notes that boilers have several options to prevent detrimental impacts by: (1) Using startup fuels, natural gas or distillate oil, until appropriate flue gas conditions have been reached and then fire residual oil; (2) pre-coating the PM control surfaces [313] with an alkaline powder (*e.g.,* limestone); (3) installing chemically resistant bags [314] in baghouses if applicable; and (4) using low-sulfur oils. The EPA also notes that currently the industry has many operational residual oil-fired boilers that are started up with either natural gas or distillate fuel oil. At these boilers, the transition from the startup fuel, distillate oil or natural gas, to residual oil is already being practiced without unacceptable impacts on APCDs including PM controls, which are operated to meet applicable opacity limits. Based on this experience and the options described above, those boilers where residual oil is used for either a part of the startup period, or as the main fuel, will also be able to operate their PM controls to meet the work practice requirements of the rule. Note that coal firing is done at high enough temperatures that concerns with condensation are not relevant. None of the commenters have specifically commented on this aspect of coal firing.

The EPA is not aware of any operational constraints applicable to operation of wet scrubbers during startup that could cause detrimental impacts on wet scrubber hardware and safety concerns and none of the commenters have commented on this aspect of wet scrubber operation.

Finally, the EPA notes that dry sorbent injection (DSI) can be applied across a very broad temperature range and will be engaged when residual oil or coal is fired in a boiler to comply with HCl requirements. Again, no comments have been received on this aspect of DSI operation.

This final rule requires work practice standards for emissions during startup and shutdown, and the rule requires sources to measure and report their emissions at all times, including periods of startup and shutdown, when continuous monitoring is used to demonstrate compliance. Data collected under this final rule will provide the EPA with information to more fully analyze this issue and address it during the 8-year review established under CAA section 112.

We now address malfunctions. In contrast to the exclusion of startup and shutdown period emissions from 30-boiler operating day rolling average emissions, the final rule requires inclusion of emissions during periods of source or APCD malfunction. We have concluded that when combined with the availability of an affirmative defense as described below, this is an appropriate and practical approach.

As mentioned earlier, periods of startup, normal operations, and shutdown are all predictable and routine aspects of a source's operations. However, by contrast, malfunction is defined as a "sudden, infrequent, and not reasonably preventable failure of air pollution control and monitoring equipment, process equipment or a process to operate in a normal or usual manner * * *" (40 CFR 63.2). The EPA has determined that CAA section 112 does not require that emissions that occur during periods of malfunction be factored into development of CAA section 112 standards. Under CAA section 112, emissions standards for new sources must be no less stringent than the level "achieved" by the best controlled similar source and for existing sources generally must be no less stringent than the average emission limitation "achieved" by the best performing 12 percent of sources in the category. There is nothing in CAA section 112 that directs the Agency to consider malfunctions in determining the level "achieved" by the best performing or best controlled sources when setting emission standards. Moreover, while the EPA accounts for variability in setting emissions standards consistent with the CAA section 112 case law, nothing in that case law requires the Agency to consider malfunctions as part of that analysis. Clean Air Act section 112 uses the concept of "best controlled" and "best performing" unit in defining the level of stringency that CAA section 112 performance standards must meet. Applying the concept of "best controlled" or "best performing" to a unit that is malfunctioning presents significant difficulties, as malfunctions are sudden and unexpected events.

Further, accounting for malfunctions would be difficult, if not impossible, given the myriad different types of malfunctions that can occur across all sources in the category and given the difficulties associated with predicting or accounting for the frequency, degree, and duration of various malfunctions that might occur. As such, the performance of units that are malfunctioning is not "reasonably" foreseeable. *See, e.g., Sierra Club* v. *EPA,* 167 F. 3d 658, 662 (D.C. Cir. 1999) (The EPA typically has wide latitude in determining the extent of data-gathering necessary to solve a problem. We generally defer to an agency's decision to proceed on the basis of imperfect scientific information, rather than to "invest the resources to conduct the perfect study."). *See also, Weyerhaeuser* v. *Costle,* 590 F.2d 1011, 1058 (D.C. Cir. 1978) ("In the nature of things, no general limit, individual permit, or even any upset provision can anticipate all upset situations. After a certain point, the transgression of regulatory limits caused by 'uncontrollable acts of third parties,' such as strikes, sabotage, operator intoxication or insanity, and a variety of other eventualities, must be a matter for the administrative exercise of case-by-case enforcement discretion, not for specification in advance by regulation."). In addition, the goal of a best controlled or best performing source is to operate in such a way as to avoid malfunctions of the source and accounting for malfunctions could lead to standards that are significantly less stringent than levels that are achieved by a well-performing non-malfunctioning source. The EPA's approach to malfunctions is consistent with CAA section 112, and we believe it is a reasonable interpretation of the statute. This approach to malfunctions has been used consistently in CAA section 112 and CAA section 129 rulemaking actions since the D.C. Circuit's decision in *Sierra Club* v. *EPA,* 551 F.3d 1019 (D.C. Cir. 2008) vacated the SSM exemption contained in CFR 63.6(f)(1) and 40 CFR 63.6(h)(1). (*See, e.g.,* National Emission Standards for Hazardous Air Pollutants From the Portland Cement Manufacturing Industry and Standards of Performance for Portland Cement Plants, 75 FR 54970 (September 9, 2010); Standards of Performance for New Stationary Sources and Emission Guidelines for Existing Sources: Sewage Sludge Incineration Units; Final Rule, 76 FR 15372 (March 21, 2011).

In the event that a source fails to comply with the applicable CAA section 112(d) standards as a result of a malfunction event, the EPA would determine an appropriate response based on, among other things, the good faith efforts of the source to minimize emissions during malfunction periods, including preventative and corrective actions, as well as root cause analyses

[313] Coal Power, May 1, 2007: *http://www.coalpowermag.com/plant_design/Coal-Plant-O-and-M-River-Locks-and-Barges-Are-an-Aging-Workforce-Too 36.html.*

[314] Neundorfer: Lesson #r, p.4–7, Table 4–1: *http://www.neundorfer.com/FileUploads/CMSFiles/Fabric%20Filter%2OMaterial [0].pdf.*

to ascertain and rectify excess emissions. The EPA would also consider whether the source's failure to comply with the CAA section 112(d) standard was, in fact, "sudden, infrequent, not reasonably preventable" and was not instead "caused in part by poor maintenance or careless operation." 40 CFR 63.2 (definition of malfunction).

Finally, the EPA recognizes that even equipment that is properly designed and maintained can sometimes fail and that such failure can sometimes cause an exceedance of the relevant emission standard. (*See, e.g.,* State Implementation Plans: Policy Regarding Excessive Emissions During Malfunctions, Startup, and Shutdown (Sept. 20, 1999); Policy on Excess Emissions During Startup, Shutdown, Maintenance, and Malfunctions (Feb. 15, 1983)). The EPA is therefore adding to the final rule an affirmative defense to civil penalties for exceedances of emission limits that are caused by malfunctions. *See* 40 CFR 63.10042 (defining "affirmative defense" to mean, in the context of an enforcement proceeding, a response or defense put forward by a defendant, regarding which the defendant has the burden of proof, and the merits of which are independently and objectively evaluated in a judicial or administrative proceeding). We also have added other regulatory provisions to specify the elements that are necessary to establish this affirmative defense; the source must prove by a preponderance of the evidence that it has met all of the elements set forth in 63.10001. (*See* 40 CFR 22.24). The criteria ensure that the affirmative defense is available only where the event that causes an exceedance of the emission limit meets the narrow definition of malfunction in 40 CFR 63.2 (*i.e.,* sudden, infrequent, not reasonable preventable and not caused by poor maintenance and or careless operation). For example, to assert the affirmative defense successfully, the source must prove by a preponderance of the evidence that excess emissions "[w]ere caused by a sudden, infrequent, and unavoidable failure of air pollution control and monitoring equipment, process equipment, or a process to operate in a normal or usual manner * * *" The criteria also are designed to ensure that steps are taken to correct the malfunction, to minimize emissions in accordance with section 63.10001 and to prevent future malfunctions. For example, the source must prove by a preponderance of the evidence that "[r]epairs were made as expeditiously as possible when the applicable emission limitations were being exceeded * * *" and that "[a]ll possible steps were taken to minimize the impact of the excess emissions on ambient air quality, the environment and human health * * *" In any judicial or administrative proceeding, the Administrator may challenge the assertion of the affirmative defense and, if the respondent has not met its burden of proving all of the requirements in the affirmative defense, appropriate penalties may be assessed in accordance with CAA section 113 (*see* also 40 CFR 22.27).

The EPA is including an affirmative defense in the final rule as we have in other recent MACT rules so as to balance the tension, inherent in many types of air regulation, to ensure adequate compliance while simultaneously recognizing that despite the most diligent of efforts, emission limits may be exceeded under circumstances beyond the control of the source. The EPA must establish emission standards that "limit the quantity, rate, or concentration of emissions of air pollutants on a continuous basis." 42 U.S.C. 7602(k) (defining "emission limitation and emission standard"). *See* generally *Sierra Club* v. *EPA,* 551 F.3d 1019, 1021 (D.C. Cir. 2008). Thus, the EPA is required to ensure that section 112 emissions limitations are continuous. The affirmative defense for malfunction events meets this requirement by ensuring that even where there is a malfunction, the emission limitation is still enforceable through injunctive relief. While "continuous" limitations, on the one hand, are required, there is also case law indicating that in some situations it is appropriate for the EPA to account for the practical realities of technology. For example, in *Essex Chemical* v. *Ruckelshaus,* 486 F.2d 427, 433 (D.C. Cir. 1973), the D.C. Circuit acknowledged that in setting standards under CAA section 111 "variant provisions" such as provisions allowing for upsets during startup, shutdown and equipment malfunction "appear necessary to preserve the reasonableness of the standards as a whole and that the record does not support the 'never to be exceeded' standard currently in force." *See* also, *Portland Cement Association* v. *Ruckelshaus,* 486 F.2d 375 (D.C. Cir. 1973). Though intervening case law such as *Sierra Club* v. *EPA* and the CAA 1977 amendments calls into question the relevance of these cases today, they support the EPA's view that a system that incorporates some level of flexibility is reasonable. The affirmative defense simply provides for a defense to civil penalties for excess emissions that are proven to be beyond the control of the source. By incorporating an affirmative defense, the EPA has formalized its approach to upset events. In a Clean Water Act setting, the Ninth Circuit required this type of formalized approach when regulating "upsets beyond the control of the permit holder." *Marathon Oil Co.* v. *EPA,* 564 F.2d 1253, 1272–73 (9th Cir. 1977). But *see, Weyerhaeuser Co.* v. *Costle,* 590 F.2d 1011, 1057–58 (D.C. Cir. 1978) (holding that an informal approach is adequate). The affirmative defense provisions give the EPA the flexibility to ensure both that its emission limitations are "continuous" as required by 42 U.S.C. 7602(k), and account for unplanned upsets and thus support the reasonableness of the standard as a whole.

F. Testing and Initial Compliance

We have carefully evaluated the wide-ranging comments on testing, continuous monitoring, and other provisions regarding initial compliance demonstrations, and we have made adjustments intended to help streamline implementation while still ensuring adequate demonstration of compliance with the emission limits and other standards established under this final rule. The significant changes include:

1. No Fuel Analysis Requirements

Apart from an alternative that allows you to analyze fuel moisture for liquid oil-fired EGUs rather than measuring HCl and HF, the final rule does not include any of the fuel analysis requirements that were in the proposed rule, either as part of initial compliance demonstrations or ongoing compliance demonstrations. In reviewing the results of the fuel analyses and the expected range of results that would be received from laboratories conducting the proposed analyses, we determined that too many results would be returned as "below detection level" and, thus, provide little information to assist with rule implementation and compliance oversight. Given the costs and efforts involved, we determined that the proposed fuel analysis requirements would not be an effective compliance monitoring tool for this final rule.

2. Clarification of Testing

We have clarified that where options for emission limits apply (such as filterable PM versus non-mercury HAP metals, or SO_2 versus HCl), you need only perform stack testing to demonstrate compliance with the selected emission limit. For example, if you elect to meet the individual non-

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mercury HAP metals standards, you must conduct the Method 29 test for the metals, and you do not have to conduct a Method 5 test for PM.

3. Low Emitting EGU Qualification

We have significantly modified the proposed requirements to qualify as a LEE unit for a pollutant other than Hg based on an initial performance test. Under the proposed rule, the operating limit monitoring provided additional assurance of compliance for a source qualified for non-mercury LEE status based on an initial compliance demonstration. Under the final rule, to qualify for LEE status for pollutants other than Hg, a unit must meet the LEE criteria for a series of performance tests over a 3-year period to demonstrate that the unit continues to perform well below the standard for which the source has obtained LEE status.

G. Continuous Compliance

The most significant changes to the testing and monitoring requirements involve the procedures for demonstrating continuous compliance. The proposed rule contained different options involving CEMS, periodic stack tests, fuel analysis, and various PM and control device operating limits. The final rule greatly simplifies the requirements and provides two basic approaches for most situations: use of continuous monitoring (either CEMS or PM continuous parametric monitoring system, CPMS) or periodic quarterly testing. The final rule does not contain the proposed fuel analysis requirements. For periodic testing, the proposed rule required testing every month or every 2 months. For those EGU owners or operators who choose to use emissions testing to demonstrate compliance, the final rule requires quarterly filterable PM or non-mercury metals HAP, whether individual or total metals, testing for coal- and liquid oil-fired units. The rule requires quarterly HCl testing for coal-fired units and quarterly HCl and HF testing, along with site-specific monitoring for liquid oil-fired units to ensure compliance with the HCl and HF standards. The final rule also has a separate compliance demonstration for those liquid oil-fired EGUs that have an annual capacity factor of less than 8 percent (emission limits do not apply, just the tune-up work practice standard). For those EGU owners or operators who choose to use emissions testing to demonstrate compliance, the final rule requires quarterly filterable PM or non-mercury metals HAP, whether individual or total metals, testing for coal- and liquid oil-fired units; quarterly HCl testing for coal-fired units and quarterly HCl and HF testing, along with site-specific parameter monitoring for liquid oil-fired units to ensure compliance with the HCl and HF standards.

The continuous monitoring options remain generally intact from the proposed rule, with relatively minor clarifications concerning calculation of 30-boiler operating day averages and QA requirements.

The final rule eliminates all operating limits for PM except for the use of a PM CPMS. For the PM CPMS, the final rule clarifies procedures for setting this operating limit and how it is distinct from the PM emission limit. The PM CPMS will not be correlated as a PM CEMS under PS 11 and will produce data in terms of a signal you define. That signal could be milliamps, stack concentration, or other output signal instead of PM emissions in units of the standard. The operating limit will be set using the highest hourly average obtained from the PM CPMS during the performance test. Compliance with the limit is based on a 30-boiler operating day rolling average basis. However, the final rule also does provide for the use of a PM CEMS to determine compliance with the filterable PM emission limit if the source elects to use this approach. The EPA believes that some sources may be interested in adopting this direct approach, and so has included that option in the final rule. If this approach is selected, the PM CEMS is used as the direct method of compliance and no additional testing is required other than tests that are required as part of the QA requirements in PS 11 and Procedure 2. To use this option, the source must elect to meet the filterable PM standard, and not one of the HAP metals standards.

Apart from the operating limit for site-specific monitoring associated with liquid oil-fired EGUs, we removed the other operating limits for control devices based on a review of the comments, after considering other programs in place to ensure proper operations of controls at EGUs. Those other programs include compliance assurance monitoring under part 64, part 70, and New Source Review permit conditions, and other SIP and NSPS requirements for operating and maintaining equipment in accordance with good air pollution control practices. Those requirements, in combination with the CEMS, PM CPMS, and frequent periodic testing provisions under the final rule, will enhance the monitoring of continuous compliance with the requirements of this rule.

Because the EPA is concerned that there will be little or no monitoring in these underlying applicable requirements for acid gases at liquid oil-fired EGUs, the final rule requires a site-specific monitoring plan for those units in this subcategory that demonstrate compliance with the HCl and HF standards through quarterly performance tests. With the exception for limited-use liquid oil-fired EGUs and other monitoring options available (such as fuel moisture monitoring or HCl/HF CEMS), the EPA believes this provision will apply to few units. The owner or operator will submit the site-specific plan to identify appropriate parameters that ensure that the operations of the unit critical to meeting the HCl/HF emission limits remain consistent with conditions during performance testing. This will be approved similarly to an alternative monitoring request. The plan should include the parameters, monitoring approach, QA/QC elements, and data reduction (including averaging period) elements. Like the PM CPMS operating limit, the operating limit for acid gas control devices on liquid oil-fired EGUs will be set using the highest hourly average obtained during the HCl and HF performance tests. Compliance with the limit is based on a 30-boiler operating day rolling average basis.

Finally, we have changed the continuous compliance requirements for the performance tune-up work practice standard since the proposal. Our intent was that this work practice standard could be performed in conjunction with routine maintenance operations at a facility and be a logical extension of routine best practices for boiler inspection and optimization. Based on the comments received, we have reduced the required frequency for this inspection to every 3 years and provided incentives for neural network combustion management and optimization practices by providing a longer interval of 4 years between inspections when such systems are in use at a given EGU.

H. Emissions Averaging

We are finalizing that owners and operators of existing affected sources may demonstrate compliance by emissions averaging for existing EGUs that are located at the same facility that are within a single subcategory and that rely on emissions testing as the compliance demonstration method. In response to our request for comments on the suitability of emissions averaging and need for a discount factor, we received a range of suggestions, including requests for clarification regarding eligibility, points for and against the need for a discount factor, and suggestions to ease implementation.

As we noted at proposal, part of the EPA's general policy of encouraging the use of flexible compliance approaches where they can be properly monitored and enforced is to include emissions averaging. Emissions averaging can provide sources the flexibility to comply in the least costly manner while still maintaining a regulation that is workable and enforceable. Emissions averaging would not be applicable to new affected sources and could only be used between EGUs in the same subcategory at a particular facility. Also, owners or operators of existing sources subject to the EGU NSPS (40 CFR part 60, subparts D and Da) would be required to continue to meet the PM emission standard of that NSPS regardless of whether or not they are using emissions averaging (*i.e.,* an EGU subject to 40 CFR part 60, subpart D or Da must meet its applicable NSPS filterable PM emission limit even if it is included in a 40 CFR part 63, subpart UUUUU, emissions averaging group for filterable PM).

Emissions averaging allows owners and operators of a facility that includes existing EGUs within a subcategory to demonstrate that the source complies with the proposed emission limits by averaging the emissions from an individual affected EGU that is emitting above the proposed emission limits with other affected EGUs at the same facility that are emitting below the proposed emission limits and that are within the same subcategory. Although some commenters note that the MACT limits are low, based on the data available to the Agency, we believe that dozens of existing EGUs are achieving all of the limits and, thus, emissions averaging is a possible approach.

The final rule includes an emissions averaging compliance alternative because emissions averaging [315] represents an equivalent, more flexible, and less costly alternative to controlling certain emission points to MACT levels. We have concluded that averaging in the proposed rule could be implemented and that it would not lessen the stringency of the MACT floor limits and would provide flexibility in compliance, cost and energy savings to owners and operators. We also recognize that we must ensure that any emissions averaging option can be implemented and enforced, will be clear to sources, and most importantly, will be no less stringent than unit-by-unit implementation of the MACT floor limits.

In the final rule, the EPA is providing that sources may average emissions from existing EGUs at the same facility and within the same subcategory. Further, for Hg emissions only from existing EGUs within the same subcategory, such EGUs in an emissions averaging plan may use an alternate compliance approach consisting of a 90-boiler operating day rolling average emission limit of 1.0 lb/TBtu or 1.1E–2 lb/GWh.

In the memo entitled "The Impact of Emission Averaging Time on the Stringency of an Emission Standard" in the docket, we have illustrated why a longer-term average results in a lower limit. In essence, longer-term averages allow particularly high (or low) measurements to be averaged with many more measurements closer to the mean. This results in the highest averages from a longer-term averaging period (*e.g.,* 90 days) being lower than the highest averages in a shorter term averaging period (*e.g.,* 30 days).

We have illustrated this concept by taking Hg CEMS data and calculating rolling 30-day averages and rolling 90-day averages. The 30-day averages have greater variability and, thus, higher peaks and valleys. The 90-day average has less variability; therefore, the same unit is able to meet a tighter 90-day limit.

The EPA is providing this alternate 90-day rolling average compliance approach for Hg only. A 90-day rolling average is appropriate for Hg, and only for Hg, because the health and environmental impacts associated with Hg are related to environmental loading rather than shorter term inhalation or other acute exposure, as is the case with HCl and PM. We believe that this alternative compliance approach will provide at least the same level of environmental protection while allowing companies greater flexibility to use emissions averaging. For example, such an approach would allow for the averaging of an infrequently operated unit that is operating slightly above the standard with a more frequently operated unit that is operating below the standard in the instances when the more frequently operated unit is in a multi-day or multi-week maintenance outage.

The EPA has concluded that it is permissible to establish within a NESHAP a unified compliance regimen that permits averaging within the same facility across individual existing EGUs subject to the same standards under certain conditions. As mentioned earlier, individual EGUs within an emissions averaging group would be allowed to have emissions greater than, less than, or equivalent with the emissions limit for their subcategory, provided that the average emissions comprised from individual EGU emissions do not exceed the emissions limit for their subcategory. Averaging across affected units is permitted only if it can be demonstrated that the total quantity of any particular HAP that may be emitted by that portion of a contiguous major source that is subject to the same standards in the NESHAP will not be greater under the averaging mechanism than it could be if each individual affected EGU in the subcategory complied separately with the applicable standard. Under this test, the practical outcome of averaging is equivalent to compliance with the MACT floor limits by each discrete EGU, and the statutory requirement that the MACT standard reflect the maximum achievable emissions reductions is, therefore, fully effectuated.

As noted in the proposal preamble, in past rulemakings, the EPA has generally imposed certain limits on the scope and nature of emissions averaging programs. These limits include: (1) No averaging between different types of pollutants; (2) No averaging between sources that are not part of the same affected source; (3) No averaging between individual sources within a single major source if the individual sources are not subject to the same NESHAP; and (4) No averaging between existing sources and new sources.

The final rule fully satisfies each of these criteria. First, emissions averaging would only be permitted between individual existing sources at a single stationary source (*i.e.,* the facility), and would only be permitted between individual sources in the same subcategory in the final EGU NESHAP. Further, emissions averaging would not be permitted between two or more different affected sources. Finally, new affected sources could not use emissions averaging. Accordingly, we have concluded that the averaging of emissions across affected units in the same existing source subcategory is consistent with the CAA. In addition, the final rule requires each facility that intends to utilize emissions averaging to develop an emissions averaging plan, which provides additional assurance that the necessary criteria will be followed. In this emissions averaging plan, the facility must include the identification of: (1) All units in the averaging group; (2) the control technology installed; (3) the process parameter that will be monitored; (4) the specific control technology or pollution

[315] As long as required emission rates are designed to account for factors such as changes in averaging times.

prevention measure to be used; (5) the test plan for the measurement of the HAP being averaged; and (6) the operating parameters to be monitored for each control device. A state, local, or tribal regulatory agency that is delegated authority for this rule could require the emissions averaging plan to be submitted or even approved before emissions averaging could be used. Upon receipt, the regulatory authority would not be able to approve an emissions averaging plan differing from the eligibility criteria contained in the rule.

The final rule excludes new affected sources from the emissions averaging provision. The EPA does not believe the statute authorizes emissions averaging for new affected sources. One reason we allow emissions averaging is to give existing sources flexibility to achieve compliance at diverse points with varying degrees of add-on control already in place in the most cost-effective and technically reasonable fashion.

With the monitoring and compliance provisions that are being finalized, there is additional assurance that the environmental benefit will be realized. Further, the emissions averaging provision would not apply to individual EGUs if the EGU shares a common stack with units in other subcategories, because in that circumstance it is not possible to distinguish the emissions from each individual unit.[316]

The rule allows EGUs that rely on CEMS for compliance demonstrations to be able to participate in emissions averaging and the emissions limits are not subject to a discount. The EPA believes that the data certainty provided by units that use CEMS would be ideal for emissions averaging and the flexibility and cost-effectiveness it offers. Given the homogeneity of fuels within the rules subcategories, along with other emissions averaging criteria, the Agency believes use of a discount factor to be unwarranted for this rule.

The emissions averaging provisions in this final rule are based in part on the emissions averaging provisions in the Hazardous Organic NESHAP (HON). The legal basis and rationale for the HON emissions averaging provisions were provided in the preamble to the final HON.[317] We do not believe that we have the authority to provide for emissions averaging among EGUs in different subcategories or among EGUs not physically located at the same affected facility.

I. Notification, Recordkeeping, and Reporting

Compared to the proposed rule, the reduced continuous compliance requirements in the final rule—primarily reduced testing frequencies and removal of fuel analyses and control device or fuel operating parameter monitoring—considerably reduces the overall burden associated with recordkeeping and reporting. Based on evaluation of the comments received, we have established a provision in the final rule for submission of most CEMS data (including monitoring plan, emissions data, and QA data) through ECMPS, so that the affected industry uses a common reporting tool for submitting CEMS data.

For data other than most CEMS data, the final rule requires electronic reporting of certain data, including performance test reports, PM CPMS data, PM CEMS data, and, if approved as part of an alternative monitoring request, HAP metals CEMS data. Other reports, such as notifications, must be submitted in hard copy format or in accordance with the procedures established by state and local agencies that receive delegation for implementing this rule. In the proposed rule, we took comment on these approaches and stated our anticipation of adopting these approaches. In the final rule, we have extended the ECMPS reporting to most CEMS data to promote harmonization for CEMS data from the industry, while leaving reporting of non-CEMS data in a separate reporting system.

J. Technical/Editorial Corrections

In this final action, we are making a number of technical corrections and clarifications to 40 CFR part 63, subpart UUUUU. These changes clarify procedures for implementing the emission limitations for affected sources. We are also clarifying several definitions to help affected sources determine applicability of this rule. We have modified some proposed regulatory language based on public comments. In addition, in response to comments received (including the May 2010 notice from the Utility Air Regulatory Group (UARG) of calculation errors in the proposed Hg MACT floor limits), we have checked all calculations and made corrections where necessary.

In several places throughout the subpart, including the associated tables, we have corrected the cross-references to other sections and paragraphs of the subpart.

VII. Public Comments and Responses to the Proposed NESHAP

A. MACT Floor Analysis

1. New Data/Technical Corrections to Old Data

Comment: Many commenters identified errors in the emissions database compiled through information provided by industry in response to the 2010 information collection request (ICR) that supported development of this rule. Commenters submitted corrections to the EPA during the public comment period.

Response: The EPA has incorporated technical corrections and new data submitted prior to the end of the comment period. The corrections and new data are described in detail in a memorandum in the docket. The EPA re-ranked the sources in the MACT floor pools to the extent necessary based on the new or corrected data, and we recalculated the MACT floors as necessary based on the re-ranking of sources. The revised MACT floors were established using the same methodology set forth in the proposed rule.

2. Pollutant-by-Pollutant Approach

Comment: Many commenters raised concerns about the way the EPA determined the MACT floors using a pollutant-by-pollutant approach. Commenters contended that such a methodology produced limits that are not achievable in combination, and as such, the limits do not comport with the intent of the statute or the recent court decision (*NRDC* v. *EPA,* 2007). Commenters further added that the CAA directs the EPA to set standards based on the overall performance of "sources" and CAA sections 112(d)(1), (2), and (3) specify that emissions standards be established on the "in practice" performance of a "source" in the category or subcategory. Commenters stated that if Congress had intended for the EPA to establish MACT floor levels considering the achievable emission limits of individual HAP, it could have worded CAA section 112(d)(3) to refer to the best-performing sources "for each pollutant." Many commenters added that the EPA's discretion in setting standards is limited to distinguishing among classes, types, and sizes of sources. Commenters contend that although Congress limited the EPA's authority to parse units and sources with similar design and types, it does not allow the EPA to "distinguish" units and sources by individual pollutant as proposed in this rule (*Sierra Club* v. *EPA,* 551 F.3d 1019, 1028 (D.C. Cir. 2008)). By calculating each MACT floor

[316] The EPA has reviewed monitoring data submitted to the Agency under the Title IV Acid Rain Program. Based on that review, the EPA is unaware of any coal- and oil-fired units that share a common stack.

[317] Hazardous Organic NESHAP (59 FR 19,425; April 22, 1994).

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independently of the other pollutants, commenters contend that the combination of HAP limits results in a set of standards that only a hypothetical "best performing" unit could achieve.

Response: We disagree with the commenters who believe MACT floors cannot be set on a pollutant-by pollutant basis. Contrary to the commenters' suggestion, CAA section 112(d)(3) does not mandate a total facility approach. A reasonable interpretation of CAA section 112(d)(3) is that MACT floors may be established on a HAP-by-HAP basis, so that there can be different pools of best performers for each HAP. Indeed, as illustrated below, the total facility approach not only is not compelled by the statutory language but can lead to results so arbitrary that the approach may simply not be legally permissible.

Clean Air Act section 112(d)(3) is not explicit as to whether the MACT floor is to be based on the performance of an entire source or on the performance achieved in controlling particular HAP. Congress specified in CAA section 112(d)(3) the minimum level of emission reduction that could satisfy the requirement to adopt MACT. For new sources, this floor level is to be "the emission control that is achieved in practice by the best controlled similar source." For existing sources, the floor level is to be "the average emission limitation achieved by the best performing 12 percent of the existing sources" for categories and subcategories with 30 or more sources, or "the average emission limitation achieved by the best performing 5 sources" for categories and subcategories with fewer than 30 sources. Commenters point to the statute's reference to the best performing "sources," and claim that Congress would have specifically referred to the best performing sources "for each pollutant" if it intended for the EPA to establish MACT floors separately for each HAP.

The EPA disagrees. The language of the Act does not address whether floor levels can be established HAP-by-HAP or by any other means. The reference to "sources" does not lead to the assumption the commenters make that the best performing sources can only be the best-performing sources for the entire suite of regulated HAP. Instead, the language can be reasonably interpreted as referring to the source as a whole or to performance as to a particular HAP. Similarly, the reference in the new source MACT floor provision to "emission control achieved by the best controlled similar source" can mean emission control as to a particular HAP or emission control achieved by a source as a whole.

Commenters also stressed that CAA section 112(d) requires that floors be based on actual performance from real facilities. The EPA agrees that this language refers to sources' actual operation, but again the language says nothing about whether it is referring to performance as to individual HAP or to single facility's performance for all HAP. Industry commenters also said that Congress could have mandated a HAP-by-HAP result by using the phrase "for each HAP" at appropriate points in CAA section 112(d). The fact that Congress did not do so does not compel any inference that Congress was *sub-silentio* mandating a different result when it left the provision ambiguous on this issue. The argument that MACT floors set HAP-by-HAP are based on the performance of a hypothetical facility, so that the limitations are not based on those achieved in practice, just reiterates the question of whether CAA section 112(d)(3) refers to whole facilities or individual HAP. All of the limitations in the floors in this rule reflect sources' actual performance and were achieved in practice. As to commenters' claims that standards set in this manner cannot be met by any actual sources, we have determined that there are approximately 69 existing coal-fired EGUs that meet all of the final existing source MACT emission limits (out of 252 EGUs that reported data for Hg, PM, and HCl in the 2010 ICR) and at least one EGU that meets all of the final new source MACT emission limits.

Commenters also point to the EPA's subcategorization authority, and claim that because Congress authorized the EPA to distinguish among classes, types, and sizes of units, the EPA cannot distinguish units by individual pollutant, as they allege the EPA did in the proposed rule. However, that statutory language addresses the EPA's authority to subcategorize sources within a source category prior to setting standards, which the EPA has done for certain EGUs. The EPA is not distinguishing within each subcategory based on HAP emitted. Rather, it is establishing emissions standards based on the emissions limits achieved by units in each subcategory. Therefore, the EPA's subcategorization authority is irrelevant to the question of how the EPA establishes MACT floor standards once it has made the decision to distinguish among sources and create subcategories.

The EPA's long-standing interpretation of the Act is that the existing and new source MACT floors are to be established on a HAP-by-HAP basis. One reason for this interpretation is that a whole plant approach could yield least common denominator floors—that is, floors reflecting limited or no control, rather than performance which is the average of what best performers have achieved. *See* 61 FR 173687 (April 19, 1996); 62 FR 48363–64 (September 15, 1997) (same approach adopted under the very similar language of CAA section 129(a)(2)). Such an approach would allow the performance of sources that are outside of the best-performing 12 percent for certain pollutants to be included in the floor calculations for those same pollutants, and it is even conceivable that the worst performing source for a pollutant could be considered a best performer overall, a result Congress could not have intended. Inclusion of units that are outside of the best performing 12 percent for particular pollutants would lead to emission limits that do not meet the requirements of the statute.

For example, if the best performing 12 percent of facilities for HAP metals were also the worst performing units for acid gas HAP and the best performers for acid gas HAP were the worst performers for HAP metals, the floor for acid gases or metals would end up not reflecting best performance. In such a situation, the EPA would have to make a value judgment as to which pollutant reductions were most critical to decide which sources are best controlled.[318] Such value judgments are antithetical to the direction of the statute at the MACT floor-setting stage.

Commenters suggested that a multi-pollutant approach could be implemented by weighting pollutants according to relative toxicity and calculating weighted emissions totals to use as a basis for identifying and ranking best performers. This suggested approach would require the EPA to essentially prioritize the regulated HAP based on relative risk to human health of each pollutant, where risk is a criterion that has no place in the establishment of MACT floors, which are required by statute to be based on technology.

The central purpose of the amended air toxics provisions was to apply strict technology-based emission controls on HAP. *See, e.g.,* H. Rep. No. 952, 101st Cong. 2d sess. 338. An interpretation that the floor level of control must be limited by the performance of devices

[318] See Petitioners Brief in *Medical Waste Institute et al.* v. *EPA,* No. 09–1297 (D.C. Cir.) pointing out, in this context, that "the best performers for some pollutants are the worst performers for others" (p. 34) and "[s]ome of the best performers for certain pollutants are among the worst performers for others."

that only control some of these pollutants effectively guts the standards by including worse performers in the averaging process, whereas the EPA's interpretation promotes the evident Congressional objective of having the floor reflect the average performance of best performing sources. Because Congress has not spoken to the precise question at issue, and the Agency's interpretation effectuates statutory goals and policies in a reasonable manner, its interpretation must be upheld. *See Chevron* v. *NRDC,* 467 U.S. 837 (1984).[319]

The EPA notes, however, that if optimized performance for different HAP is not technologically possible due to mutually inconsistent control technologies (for example, if metals performance decreased as organics reduction is optimized), then this would have to be taken into account by the EPA in establishing a floor (or floors). The Senate Report indicates that if certain types of otherwise needed controls are mutually exclusive, the EPA is to optimize the part of the standard providing the most environmental protection. S. Rep. No. 228, 101st Cong. 1st sess. 168 (although, as noted, the bill accompanying this Report contained no floor provisions). It should be emphasized, however, that the D.C. Circuit has stated that "the fact that no plant has been shown to be able to meet all of the limitations does not demonstrate that all the limitations are not achievable." *Chemical Manufacturers Association* v. *EPA,* 885 F. 2d at 264 (upholding technology-based standards based on best performance for each pollutant by different plants, where at least one plant met each of the limitations but no single plant met all of them).

All available data for EGUs indicate that there is no technical problem achieving the floor levels contained in this final rule for each HAP simultaneously, using the MACT floor technology. Data demonstrating a technical conflict in meeting all of the limits have not been provided, and, as stated above, based on the available data, there are approximately 64 EGUs that meet all of the final existing source emission limits and at least one EGU that meets all of the final new source emission limits.

[319] Because industry commenters argued that the statute can only be read to allow floors to be determined on a single source basis, commenters offered no view of why their reading could be viewed as reasonable in light of the statute's goals and objectives. It is not evident how any statutory goal is promoted by an interpretation that allows floors to be determined in a manner likely to result in floors reflecting emissions from worst or mediocre performers.

3. Minimum Number of EGUs To Set Floors

Comment: Many commenters indicated that CAA section 112 requires that data from a minimum of 5 units are required to set MACT floors for existing sources. Commenters noted that the EPA's use of less than 5 units for subcategories with greater than 30 units is a legalistic reading of CAA section 112 that could result in such absurd results as using 5 units to set MACT floors for a subcategory with 29 units and data for only 10 units, but using a single unit to set MACT floors for a subcategory with 31 units and data for only 10 units.

Response: The EPA does not agree that CAA section 112(d)(3) mandates a minimum of 5 sources in all instances, notwithstanding the incongruity of having less data to establish floors for larger source categories than is mandated for smaller ones. The literal language of the provision appears to compel this result. CAA section 112(d)(3) states that for categories and subcategories with at least 30 sources, the MACT floor for existing sources shall be no less stringent than the average emission limitation achieved by the best-performing 12 percent of the sources for which the Administrator has emissions information. The plain language of this provision requires the use of fewer data points for large source categories than for small source categories where the Administrator only has emissions information on a small number of units for categories and subcategories with 30 or more sources. Furthermore, commenters contend that Congress could not have intended the floors for a subcategory with 29 sources to be based on 5 sources and a subcategory with 31 sources to be based on less than that number; but we maintain this contention is without merit because 12 percent of 31 is 3.72 (rounded to 4) so the EPA would not base standards for a subcategory with 31 sources on 5 sources even if we had data on all 31 sources in the subcategory. For these reasons, we decline to adopt commenters' position and continue to adhere to the clear statutory directive.

4. Treatment of Detection Levels

Comment: Commenters stated that when setting the MACT floors, non-detect values are present in many of the datasets from best performing units. Commenters provided input on how these non-detect values should be treated in the MACT floor analysis. Some commenters agreed that it is appropriate to keep the detection levels as reported, while certain commenters suggested that the detection levels should be replaced using a value of half the method detection limit (MDL). Many other commenters stated that data that are below the detection limit should not be used in setting the floors, and these data should be replaced with a higher value including either the MDL, limit of quantitation (LOQ), practical quantitation limit (PQL), or reporting limit (RL) for the purposes of the MACT floor calculations. Other commenters stated all non-detect values should be excluded from the floor analysis, or all values should be treated as zero.

Some commenters stated it is necessary to keep the data as reported because changing values would lead to an upward bias. Additional commenters agreed with this basic premise, but suggested that replacing non-detect data with a value of half the MDL is appropriate while still minimizing the bias. They noted that treating measurements below the MDL as occurring at the MDL is statistically incorrect and violates the statute's "shall not be less stringent than" requirement for MACT floors. One commenter also provided a reference for a statistical method based on a log-normal distribution of the data which estimated the "maximum likelihood" of data values; this result is slightly higher than half the MDL.

Some commenters stated that it is necessary to substitute the MDL value when performing the MACT floor calculations. With MDL defined as the lowest concentration that can be distinguished from the blank at a defined level of statistical significance, this is an appropriate value. If MDL values are not reported, one commenter suggested an approach for estimating an MDL equivalent value, but recognized that the background laboratory and test report files may not be available to the EPA in order to derive these estimates.

Most commenters representing industry and industry trade groups argued that either LOQ or PQL values should replace non-detects. The LOQ is defined as the smallest concentration of the analyte which can be measured. These commenters contended that the LOQ leads to a quantifiable amount of the substance with an acceptable level of uncertainty. A few commenters provided calculations showing some of the proposed MACT floors were below the LOQ. Additionally, some of these commenters stated that using LOQ or PQL values also incorporates additional sources of random and inherent sampling error throughout the testing process, which is necessary. These errors occur during sample collection, sample recovery, and sample analysis;

MDL values only account for method specific (*e.g.*, instrument) errors. These commenters contended that the three times the MDL approach discussed in the proposal accounts for some measurement errors but does not account for these unavoidable sampling errors. The commenters also noted that an LOQ is calculated as 3.18 times the MDL, and PQL is calculated as 5 to 10 times the MDL. Many of the commenters in support of using either an LOQ or PQL value ultimately believed a work practice is more appropriate where a MACT floor limit is below either of these two values. They cited CAA section 112(h)(1) which allows work practices under CAA section 112(h)(2) if "the application of measurement methodology to a particular class of sources is not practicable due to technological and economic limitations". These commenters stated that the inability of sources to accurately measure a pollutant at the level of the MACT floor qualifies as such a technological limitation that warrants a work practice standard.

Commenters stated that where the proposed MACT floor is below the LOQ or PQL then that source category has a technological measurement limitation. A few commenters suggested RL values should be used when developing the floor limits. They stated that the RL is the lowest level at which the entire analytical system gives reliable signals and includes an acceptable calibration point. They added that use of an acceptable calibration point is critical in showing that numbers are real versus multiplying the MDL by various factors.

Several commenters stated that all non-detect values should be excluded from MACT floor calculations. They believed that excluding all non-detect values would eliminate any potential errors or accuracy issues related to testing for compliance. Due to inconsistencies of the MDL value reported for non-detect data, one commenter suggested treating all such values as zero. This would provide a consistent approach for setting the floor as well as determining compliance.

Several commenters provided input on the EPA's proposed method of three times the MDL as an option for setting limits. A few commenters in support noted that this approach provided a reasonable method to account for data variability as it took into account more than just analytical instrument precision. Many other commenters argued that this method results in limits which are too low, namely that it is still lower than the LOQ value which they are in favor of as a substitute for any reported non-detect data. Other commenters disagreed with this method and claimed that it would lead to results which introduce a high bias in the floor setting process. A few contended that multiplying by 3 would introduce a 300 percent error into the floor, resulting in a floor that is less stringent than required by the Act. Others suggested that the MDL values are antiquated and already too high and thus it is not appropriate to multiply them by three. Also, a few commenters suggested multiplying the MDL by three would not reflect the actual lower emissions achieved by any source and as such is unlawful under CAA section 112(d).

Response: We agree with many of the comments related to treatment of data reported as detection limit values in the development of MACT floors and emissions limits. As we noted at proposal, the statistical probability procedures applied in calculating the floor or an emissions limit inherently and reasonably account for emissions data variability including measurement imprecision when the database represents multiple tests from multiple emissions units for which all of the data are measured significantly above the method detection level. That is less true when the database includes emissions occurring below method detection capabilities regardless of how those data are reported.

The EPA's guidance to respondents for reporting pollutant emissions used to support the data collection specified the criteria for determining test-specific method detection levels. Those criteria ensure that there is only about a 1 percent probability of an error in deciding that the pollutant measured at the method detection level is present when in fact it was absent. (Reference: ReMAP: PHASE 1, Precision of Manual Stack Emission Measurements; American Society of Mechanical Engineers, Research Committee on Industrial and Municipal Waste, February 2001.) Such a probability is also called a false positive or the alpha, Type I, error. This means specifically that for a normally distributed set of measurement data, 99 out of 100 single measurements will fall within ±2.54 × standard deviation of the true concentration. The anticipated range for the average of repeated measurements comes progressively closer to the true concentration. More precisely, the anticipated range varies inversely with the square root of the number of measurements. Thus, for a known standard deviation (SD) of anticipated single measurements, the anticipated range for 99 out of 100 future triplicate measurements will fall within ±2.54 SD/$\sqrt{3}$ of the true concentration. This relationship translates to an expected measurement imprecision for an emissions value occurring at or near the method detection level of about 40 to 50 percent.

By assuming a similar distribution of measurements across a range of values and increasing the mean value to a representative higher value (*e.g.*, 3 times minimum detection level or 3xMDL), we can estimate measurement imprecision at other levels. For an assumed 3xMDL, the estimated measurement imprecision for a three test run average value would be on the order 10 to 20 percent. This is about the same measurement imprecision as found for Methods 23 and 29 indicated in the ASME ReMAP study for the sample volumes prescribed in the final rule (*e.g.*, 4 to 6 dscm) for multiple tests.

Analytical laboratories often report a value above the method detection limit that represents the laboratory's perceived confidence in the quality of the value. This independently adjusted value is expressed differently by various laboratories and is called LOQ, PQL, or RL. In many cases, the LOQ, PQL, or RL is simply a multiplication of the method detection limit. Commonly used multipliers range from 3 to 10. Because these values reflect individual laboratories' perceived confidence, and, therefore, could be viewed as arbitrary, we decline to adopt the LOQ, PQL, or RL because such approaches in our view would inappropriately inflate the MACT floor standards. Our alternative to those inconsistent approaches is discussed below.

Consistent with findings expressed in reports of emissions measurement imprecision and the practices of analytical laboratories, we believe that using a measurement value of 3 times a representative method detection limit established in a manner that assures 99 percent confidence of a measurement above zero will produce a representative method reporting limit suitable for establishing regulatory floor values.

On the other hand, we also agree with commenters that an emissions limit set from a small subset of data or data from a single source may be significantly different than the actual method detection levels achieved by the best performing units in practice. This fact, combined with the low levels of emissions measured from many of the best performing units, led the EPA since proposal to review and revise the procedure intended to account for the contribution of measurement imprecision to data variability in establishing effective emissions limits. In response to the comments about the

quality of measurements at very low emissions limits especially for new sources, we revised the procedure for identifying a representative method detection level (RDL).

The revised procedure for determining an RDL starts with identifying all of the available reported pollutant-specific method detection levels for the best performing units regardless of any subcategory (*e.g.,* existing or new, fuel type, etc.). From that combined pool of data, we calculate the arithmetic mean value. By limiting the data set to those tests used to establish the floor or emissions limit (*i.e.,* best performers), which in this case is a larger data set than normally available for establishing NESHAP, we believe that the result is representative of the best performing testing companies and laboratories using the most sensitive analytical procedures. We believe that the outcome should minimize the effect of a test(s) with an inordinately high method detection level (*e.g.,* the sample volume was too small, the laboratory technique was insufficiently sensitive, or the procedure for determining the minimum value for reporting was other than the detection level). We then call the resulting mean of the method detection levels the representative detection level (RDL) because it is characteristic of accepted source emissions measurement performance.

The second step in the process is to calculate 3xRDL to compare with the calculated floor or emissions limit. This step is similar to what we have used for other NESHAP including the Portland Cement rule. As outlined above, we use the multiplication factor of 3 to reduce the imprecision of the analytical method until the imprecision in the field sampling reflects the relative method precision as estimated by the ASME ReMAP study. That study indicates that such relative imprecision remains a constant 10 to 20 percent over the range of the method. For assessing the calculated floor results relative to measurement method capabilities, if 3xRDL were less than the calculated floor or emissions limit (*e.g.,* calculated from the upper predictive limit, UPL), we would conclude that measurement variability was adequately addressed with the initial floor calculation. The calculated floor or emissions limit would need no adjustment. If, on the other hand, the value equal to 3xRDL were greater than the UPL, we would conclude that the calculated floor or emissions limit did not account entirely for measurement variability. Where such was the case, we substituted the value equal to 3xRDL for the calculated floor or emissions limit (UPL) which results in a concentration where the method would produce measurement accuracy on the order of 10 to 20 percent similar to other EPA test methods and the results found in the ASME ReMAP study.

We determined the RDL for each pollutant using data from tests of all the best performers for all of the final regulatory subcategories (*i.e.,* pooled test data). We applied the same pollutant-specific RDL and emissions limit assessment and adjustment procedures to all subcategories for which we established emissions limits. We believe that adjusting emissions limits in this manner, which ensures that measurement variability is adequately addressed relative to compliance determinations, is a better procedure than the one applied at proposal, which was based on more limited data. We also believe that currently available emissions testing procedures and technologies provide the measurement certainty sufficient for sources to demonstrate compliance at the levels of the revised emissions limits.

5. Basis for New Source MACT

Comment: Several commenters stated that the proposed limits set for new EGUs do not represent the best performing EGU. The commenters state that the EPA has chosen the strictest limit irrespective of the EGU and that limits for new EGUs should be achievable. According to the commenters, no existing EGU is currently meeting the proposed limits, which will result in a moratorium on the construction of new coal-fired EGUs. Further, commenters state that another result of the EPA's flawed approach is that the proposed standards for new EGUs are so low that adequate test methodologies to demonstrate compliance do not exist. Without accurate testing methodologies, commenters assert that contractors will not guarantee that potential emission control technologies will meet the proposed standards. Without accurate test methodologies and vendor guarantees, commenters believe that financing of new facilities will be virtually impossible to secure which will, in turn, effectively preclude the construction of any new coal-based EGUs.

Commenters also stated that the EPA failed to address cumulative effects of using multiple pollution control devices in determining MACT levels applicable to PM levels. In proposing total PM as a surrogate, commenters believe that the EPA failed to consider or address the antagonistic effects that adding multiple pollution control devices can have on an EGU's HAP emissions. Commenters indicated that EGUs would not be able to comply with the proposed new source HCl limit without adding a scrubber or some type of sorbent injection to control HCl emissions. Adding these HCl control technologies will increase the total PM emissions of these units. According to commenters, because a fabric filter-alone configuration (the basis for the new source PM limit) would not meet all MACT limits, these units may not be the best-performing units.

Response: The EPA disagrees with the commenters' statements that no existing unit is currently meeting the new source limits. The EPA established the new source limits based on data from existing EGUs and there is at least one EGU, based on the data available, that is meeting all three final HAP limits and at least eight EGUs that are meeting one or more of the new source limits. As a result of comments received on the full body of data, the EPA has re-ranked the best performing EGUs and reviewed the new source limits based on the re-ranking where appropriate. Based on the revised ranking, the best performing source for PM has changed and that source now forms the basis for the new source filterable PM limit in the final rule. The source is a coal-fired EGU that includes the entire suite of controls that would likely be required on a new coal-fired source constructed prospectively (*i.e.,* it is a unit with SCR, dry FGD, and FF). Thus, the commenters' concerns are no longer relevant as they relate to PM emissions from coal-fired EGUs.

The EPA also believes that the EGUs serving as the basis for the new source Hg and HCl limits in the final rule are representative of what a new coal-fired EGU would look like to meet all of the requisite regulations applicable to EGUs (*e.g.,* NSPS and the CSAPR) as they also include the entire suite of controls that would likely be required on a new coal-fired source constructed prospectively. The EPA has also taken into account the ability of the various test methods to accurately measure emissions at the levels being demonstrated by the EGUs in the top performing 12 percent in establishing the final limits, and we have determined that there are adequate test methods to measure the regulated HAP at the new source levels.

6. Achievability of Limits

Comment: A number of commenters state that the EPA has chosen the strictest limit irrespective of the unit and that limits for new EGUs should be achievable. According to the

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commenters, no existing unit is currently meeting the proposed new source limits, which will result in a moratorium on the construction of new coal-fired units. The commenters state that this regulation goes beyond protecting public health and will impact the country's choice of fuel for energy production. Other commenters state that another result of the EPA's flawed approach is that the proposed standards for new units are so low that adequate test methodologies to demonstrate compliance do not exist. Without accurate testing methodologies, commenters allege that contractors will not guarantee that potential emission control technologies will meet the proposed standards. Without accurate test methodologies and vendor guarantees, commenters believe that financing of new facilities will be virtually impossible to secure, and that this in turn will effectively preclude the construction of any new coal-based units. Commenters maintain that adopting standards effectively banning new coal units amounts to a momentous change in national energy policy without discussion or analysis and far exceeds the EPA's authority.

Some commenters add that the proposed new source MACT standards do not represent rates that have been achieved in practice and are orders of magnitude lower than any of the CAA section 112(g) case-by-case MACT limits established for the most advanced units in the U.S. coal fleet by multiple state agencies.

Other commenters stated that the synergistic impact of multiple controls has not been taken into account in the proposed rules. Commenters argue that circumstances exist with respect to the control of acid gases, which will require scrubbers or other SO_2 controls that add particulate to the flue gas stream, and that added particulate must be removed by PM control devices along with the particulate added to the flue gas for EGUs that need to install ACI for Hg control. Because particulate devices provide a fixed percent reduction of particulate, commenters assert that it is mathematically certain that PM performance will decrease because control of both acid gases and Hg would add PM to the flue gas stream which would in turn decrease performance of the PM control on the relevant mass metric. As a consequence, commenters allege that there is no assurance that sources can meet the EPA's "cherry-picked" floors for acid gases and for Hg by "optimizing" these systems to meet the performance of the floor units because to do so would impact their ability to meet the EPA's similarly "cherry-picked" total PM floor standard.

The commenters state that, for existing sources as with the new source standard-setting approach, a pollutant-by-pollutant approach does not consider what the top performing 12 percent achieve in practice for all pollutants and does not consider the antagonistic effects of the concurrent use of various control technologies. For example, one commenter states that 47 of the 131 sources used to calculate the existing source total PM limit only had PM control but no acid gas or Hg controls that could emit additional PM. According to the commenter, the CAA is clear that standards must be based on actual sources and not the product of a pollutant-by-pollutant determination resulting in a set of composite standards that do not necessarily reflect the overall performance of any actual source. To address these issues, the commenter recommends that the EPA use an approach that more accurately reflects what actual best performing sources achieve.

Response: The EPA disagrees with the commenters' contention that the pollutant-by-pollutant approach to establishing MACT floors is inconsistent with the CAA for the reasons set forth in the response to comments on the EPA's MACT floor setting process. In addition, the EPA established the proposed new source limits based on data from existing EGUs, and there are EGUs that are able to meet the new source limits. To the extent the commenters are concerned that no existing source is simultaneously meeting all of the new sources limits, we note that the EPA has revised the new source standards based on comments and data corrections that industry made to data it incorrectly provided in response to the utility ICR. We have identified at least one source that is meeting all of the new source MACT limits in the final rule.

We disagree with commenters that suggest the proposed new source standards are invalid because they are more stringent than CAA section 112(g) case-by-case MACT limits established by state agencies. As commenters note, states, not the EPA, established the CAA section 112(g) standards, and they did so based on the information available to them. The EPA likewise must establish CAA section 112(d) standards based on the available data. We have considered the available data and information, including the 2010 ICR data, and complied with the requirements of CAA section 112(d) in establishing the standards in this final rule. That the final standards are more stringent than CAA section 112(g) standards issued by certain state agencies has no bearing on the legitimacy of the standards at issue here.

The EPA agrees with commenters that the SO_2 and some Hg controls may add to the PM loading and that it is reasonable to establish the new source standard based on an EGU that has a suite of controls that will be required of any new source. For example, new coal-fired EGUs will be required to comply with the utility NSPS and may have to comply with the CSAPR and other requirements (*e.g.,* SIP or state-only requirements). Commenters are also correct that the proposed new source PM surrogate standard was based on a source that is not like a coal-fired EGU that would be constructed today (*i.e.,* an EGU with only PM control and no SO_2 controls).

The final standard is not based on the source used to establish the proposed limit. As stated above, industry commenters provided data corrections and new data and the EPA considered that new and revised data in establishing the final standards. We re-ranked all the coal-fired EGUs based on the new data. The new ranking of coal-fired EGUs resulted in a change of the source we used to establish the new source PM surrogate standard for non-mercury metal HAP. The basis for the new source limit in the final rule is a unit that has a full suite of controls similar to what would be required for any new coal-fired EGUs (*i.e.,* it is a unit with SCR, dry FGD, and FF). The EPA has identified at least one EGU meeting all of the final new source limits; thus, the EPA does not believe that it is finalizing standards that "ban" new coal-fired generation as indicated by the commenter.

The EPA also disagrees that the final new source standards are so stringent that there are not adequate test methods available to determine compliance with the standards. The EPA has taken into account the ability of the various test methods to accurately measure emissions at the levels being demonstrated by the best performing EGUs in establishing the final limits. This has been done through use of the 3XRDL (discussed elsewhere in this preamble and the Response to Comments document) and through adjustments to the sampling time requirements for certain of the HAP.

7. Comments on Technical Approaches

Comment: Commenters disagreed with the EPA's use of data from multiple units exhausting through a common stack and argued that the EPA unreasonably treated data from multiple

units exhausting through a single stack as multiple data points in establishing the MACT floors. The commenters believe it is improper to count a single data point from a multiple-unit common stack as multiple data points. The commenters state that where two units exhaust through a common stack, the performance is not that of two sources, but only one. The commenters indicate that emissions performance that is actually achieved reflects combined operation, which cannot rationally be split into two parts (data points) because this emissions performance was not achieved by two separate sources. Commenters assert that although it may be acceptable for the EPA to surmise that the combined performance of multiple EGUs and pollution control devices represents an emissions control strategy that could be a best performer, thereby entitling the Agency to use the data at all, the fact is there is only one performer not two. Commenters contend that apart from being inconsistent with applicable MACT case law, counting combined stack emissions as two or more data points is unreasonable because it dampens variability and over-represents the emissions data by creating multiple "performers" or sources when there is in fact only one. Commenters note that in the major-source Industrial Boiler NESHAP, the EPA argued its approach of creating two data points from a single combined stack data point is reasonable because it cannot separate the comingled fraction of the emissions from the different emission points. Commenters state that this is irrelevant, believing that there is no basis to separate these emissions because the MACT floor is based on best performing sources and there is only a single source.

According to commenters, the EPA cannot determine what amount of the overall performance of a combined stack data point is the specific result of the combination. Commenters assert that the EPA also argues that applying the emissions equally to multiple units exhausting through a single stack "accurately represents the emissions of those units on average." Commenters believe that is simply not correct and there is no plausible factual basis for that statement, believing that there is no unit that "achieved" those emissions. Rather, the data represent the combined weighted average of two units, without knowing how either unit actually performed. One commenter also stated that in several instances when a facility operated tandem or multiple EGUs but only submitted a single stack measurement, the EPA used the single stack measurement to represent Hg emissions from the facility's other stacks.

Response: The EPA disagrees with commenters. As in the major-source Industrial Boiler NESHAP, the EPA continues to believe that the emissions from the common stack represent the average emissions of the EGUs exhausting to the common stack and are representative of both EGUs. Commenters have provided no data to support the contention that this assumption is false. In addition, commenters' contention that distinct EGUs (*i.e.,* boilers) are one source if they emit out of a common stack is not consistent with the CAA section 112(a)(8) definition, which clearly applies to the individual boiler units with a capacity of more than 25 MW. It would not be reasonable in light of that definition to consider the emissions from two boilers to a common stack as the emissions of one EGU. The EPA only used data from combined stacks where both EGUs were operating or where the owner/operator certified that no air leakage could occur. The EPA expects that companies will comply with the final rule by conducting testing at the common stack as that is usually where the sampling locations are (rather than in the intermediate ductwork) and will report the results as being for each EGU.

The EPA has reviewed the data based on comments received and does not believe that there are any inconsistencies in the data set used for the final rule. In the MACT floor analysis, the EPA only used data from stacks that were tested or for which test data were provided. These stack measurements were not used to represent emissions from other, non-tested, stacks in the MACT analysis.

8. Alternative Units for Emission Limits

Comment: Several commenters submitted a variety of alternatives to the input- or output-based MACT floor limits as means of establishing the MACT floors. Some commenters suggested emission reductions or removal efficiencies. These commenters suggest that a percent reduction MACT metric be considered as an alternative, and not a substitute, to some of the proposed MACT numerical limits, particularly those that appear too problematic to meet in reality. A necessary data format and protocol could be developed for some HAP, such as Hg, that would allow an appropriate percent reduction alternative to be developed. Commenters believe that the Brick MACT decision stands for the proposition that a MACT level cannot be based on a specific technology; commenters are advocating that a percent reduction format would specify the level or reduction but would not dictate any specific control or methodology.

Comments were also received that some state programs contain Hg emission limits that are more stringent than the EPA's proposed emission limits. The programs of Connecticut, Massachusetts, New Hampshire, New Jersey, and New York were noted. Commenters provided information on these states' Hg emission limits, which often are in the form of either a lb/TBtu format or a percent reduction. Commenters noted that EGUs in these states were in compliance with the state regulations and, therefore, the EPA's emission limits should be more stringent.

Response: The EPA disagrees with the commenters' suggestion that a percent reduction standard should be included in the final rule. The EPA notes that the inability to account for Hg removed from the coal prior to combustion was not the only reason provided for not using a percent reduction format. As noted in the proposal preamble (76 FR 25040), we did consider using a percent reduction format for Hg. We determined not to propose a percent reduction standard for several reasons. The percent reduction format for Hg and other HAP emissions would not have addressed the EPA's desire to promote, and give credit for, coal preparation practices that remove Hg and other HAP before firing because we did not have the data to account for those practices. Specifically, to account for the coal preparation practices, sources would be required to track the HAP concentrations in coal from the mine to the stack, and not just before and after the control device(s). Such an approach would be difficult to implement and enforce. Moreover, we do not have the data necessary to establish percent reduction standards for HAP at this time. Depending on what was considered to be the "inlet" and the degree to which precombustion removal of HAP was desired to be included in the calculation, the EPA would need (*e.g.*) the HAP content of the coal as it left the mine face, as it entered the coal preparation facility, as it left the coal preparation facility, as it entered the EGU, as it entered the control devices, and as it left the stack to be able to establish percent reduction standards. We do not have this type of information.

The EPA believes that an emission rate format allows for, and promotes, the use of pre-combustion HAP removal processes because such practices will

help sources assure they will comply with the proposed standard. A percent reduction requirement would likely limit the flexibility of the regulated community by requiring the use of a control device. In addition, as discussed in the Portland Cement NESHAP (75 FR 55002; September 9, 2010), the EPA believes that a percent reduction format negates the contribution of HAP inputs to EGU performance and, thus, may be inconsistent with the D.C. Circuit's rulings as restated in the *Brick* case (479 F.3d at 880) which say, in effect, that it is the emissions achieved in practice (*i.e.,* emissions to the atmosphere) that matter, not how one achieves those emissions.

The 2010 ICR data confirm that plant inputs likely play a role in emissions to the atmosphere. These data indicate that some EGUs are achieving lower Hg emissions to the atmosphere at a lower Hg percent reduction (*e.g.,* 75 to 85 percent) than are other EGUs with higher percent reductions (*e.g.,* 90 percent or greater). However, we are not sure whether these data accurately reflect the total percent reduction mine-to-stack because we do not have all the data necessary to make that determination. Thus, we proposed to establish numerical emission standards for Hg HAP emissions from EGUs and we are finalizing numerical emission standards. The same issues prevent us from considering percent reduction standards for the other HAP emitted from EGUs.

With regard to the comments relating to some state programs being more stringent than the EPA's proposed limits, the EPA would note that many of the programs identified by one commenter have an "either/or" format for their Hg standards. That is, an EGU can either meet an emission limit (*e.g.,* lb/TBtu) or achieve a percent reduction. The commenter did not note which form of the standard the EGUs were meeting so it is unclear whether the standards are in fact more stringent. In any case, CAA section 112(d) does not mandate that federal standards be more stringent than state requirements for HAP emissions. Furthermore, states are authorized to establish standards more stringent than this final NESHAP so promulgation of this rule will in no way affect a source's responsibility to comply with an otherwise applicable state Hg or other HAP standard.

9. Beyond-the-Floor

Comment: Several commenters stated that the proposed beyond-the-floor Hg limit for low rank coal EGUs is based on too little data and is technically and economically unattainable, noting that the EPA's proposed beyond-the-floor limit is based on only three samples from a single test held at only one EGU, which is not enough data to develop such a limit, especially as more data were available for this EGU in the database. Commenters noted that although this one EGU may have been able to achieve the proposed limit during this one test, the three samples are not adequate to demonstrate the long-term ability of this EGU to meet that limit consistently, let alone the long-term abilities of the top 12 percent of all low rank coal EGUs to meet that limit consistently. Given Texas lignite's particularly high rates of variability of Hg concentration, and the inability to minimize this variability, the commenters believe that the EPA is obliged to have more, not less, data to support the proposed beyond-the-floor Hg limit for low rank coal EGUs. One commenter added that the EPA's decision to require a beyond-the-floor limit for the low rank virgin coal subcategory does not comply with CAA section 112(d)(2). Some commenters also contended that the EPA failed to include the cost of a baghouse in its beyond-the-floor analysis. They note that, according to the EPA, in order to comply with the proposed EGU MACT rule, units will either fuel switch to a lower Hg fuel or retrofit air pollution controls.

Response: The EPA notes that all of the low rank virgin coal-fired EGUs for which data were submitted in response to the 2010 ICR were meeting the Hg floor limit (11 lb/TBtu). Four of the EGUs have ACI systems installed and three of the four EGUs tested were also meeting the beyond-the-floor Hg emission limit of 4.0 lb/TBtu. Those three units were achieving control levels of greater than 95 percent (fuel to stack). The other low rank virgin coal-fired EGUs that are not currently meeting the beyond-the-floor emission limit do not have installed Hg-specific controls. An analysis of the Hg content of the fuel used during the 2010 ICR testing suggests that control in the range of 80 to 90 percent (fuel to stack) would be needed to meet the beyond-the-floor limit of 4.0 lb/TBtu. One low rank virgin coal-fired EGU achieved 75 percent control with no Hg-specific control technology (*e.g.,* ACI).

The EPA believes that its beyond-the-floor analysis is appropriate, including the costs analyzed. The EPA's cost analysis is meant to serve as an average for all sources in the subcategory recognizing that some EGU's costs will be more and some less; EGUs whose costs are higher are not exempted from the regulation. Further, five EGUs in the subcategory are meeting the final beyond-the-floor limit based on available data (*see* the MACT Floor analyses in the docket), and, in any case, CAA section 112(d) does not require that a specified percentage of sources in a category or subcategory be able to meet the MACT standard that is established. This is even truer for beyond-the-floor standards which are set at levels beyond what the average of the best performing sources are achieving in practice and instead based on what is achievable. Commenters have failed to provide any data that supports the contention that some EGUs in the subcategory will not be able to achieve the standards with additional controls.

Comment: Commenters indicated that the EPA has not justified a beyond-the-floor limit for Hg for new IGCC units. The EPA's choice of the beyond-the-floor Hg limit for new IGCCs is not derived from IGCC test data from the 2010 ICR and commenters allege that the EPA has not provided adequate justification for its decision from a technology capability assessment. Commenters note that ACI for Hg treatment of coal-derived syngas is not in use in any operating IGCC plant today, nor can it be used in the same fashion as it is used at conventional coal-fired EGUs. Commenters assert that the EPA also lacks data with respect to new IGCC units, yet the EPA proposed beyond-the-floor MACT limits for new IGCC sources. The commenters assert that the EPA's limits for new IGCC sources are based on beliefs, predictions, projections and design target assumptions. The limits from the 2007 DOE Report referenced in the preamble are based on environmental target assumptions. These IGCC environmental targets were chosen to match Electric Power Research Institute (EPRI) design basis from their Coal Fleet for Tomorrow Initiative. Commenter states that EPRI notes that these were design targets and were not to be used for permitting values. Commenters assert that the EPA has simply not justified its process for going beyond-the-floor for new IGCC units and that, without sufficient justification, the EPA actions are unsupported.

Two commenters provided permit information, based on IGCC units currently under construction, for PM and Hg emissions. One commenter requested that the proposed new MACT floor limit for PM be modified to address the two scenarios for duct burners at IGCC plants, syngas-fired and natural-gas-fired. The commenter requested the 0.050 lb/MWh limit be increased to at least 0.068 lb/MWh

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based on gross energy output from the combined cycle generating unit when operated with duct burners fired with syngas. The 0.068 lb/MWh value is consistent with the calculated emission ceiling for its permit to construct for this operating scenario. According to the commenter, there is not sufficient experience with syngas turbines for manufacturers to guarantee performance in the 0.050 lb/MWh range. The 0.0681b/MWh performance basis proposed by the commenter was calculated based on the emission guarantees that the commenter was able to obtain for a turbine fired on the syngas. The commenter also requested that the 0.050 lb/MWh limit be increased to 0.083 lb/MWh based on gross energy output from the combined cycle unit when operated with duct burners fired by natural gas. The commenter indicated that, depending on market conditions, the syngas produced at an IGCC may have more value as a raw material for producing co-products than it would have as duct burner fuel. Where that is the case, the economic viability of an IGCC would be enhanced by firing the duct burners on natural gas and diverting that syngas to manufacture of a co-product. The commenter's air permits are currently based on the use of syngas as duct burner fuel; however, the commenter is currently examining an alternative operating scenario that may result in amendments to the air permits to authorize firing natural gas in the duct burners. Commenter states that preliminary calculations indicate that the PM limit would need to be set at 0.083 lb/MWh gross energy output when operated with duct burners fired with natural gas.

The commenter also noted that there is not sufficient test data to precisely predict the Hg emissions performance of even the best-controlled IGCC units, other than that IGCC Hg emissions are expected to be much less than those for EGUs that directly burn coal. In its permit application, the commenter proposed to establish a new standard for Hg removal in IGCC units by treating the syngas in catalytic reactors. The catalytic reactor system is expected to achieve greater than 95 percent Hg removal using either sulfur-impregnated activated carbon or alumina catalyst. In the absence of actual stack test data, the commenter has had to estimate expected emissions based on engineering estimates of how much Hg may arrive in the syngas routed to the catalytic reactors. Based on these engineering estimates and 95 percent Hg removal in the catalytic reactors, the commenter believes that the resulting Hg emission limit for a state-or-the-art IGCC unit would be 0.003 lb/GWh, which is much less than the Hg emissions for EGUs that directly burn coal.

The commenter notes that IGCC units are still in their infancy. Funding for them will be very difficult or unavailable if there is a regulatory limit below the level that can be supported by vendor guarantees. Given the important role that IGCC units may have in meeting global energy and climate stability goals, the commenter believes it would be a mistake to erect barriers to the implementation of this technology. The commenter stated that the EPA can reevaluate the appropriate levels for future IGCC units after demonstration units which incorporate effective controls have been built and tested.

Response: The EPA is not finalizing the proposed new source standards for IGCC units. As commenters noted, EPA proposed beyond-the-floor limits for IGCC units based on the performance of PC-fired EGUs and solicited data from IGCC units that would represent what a new IGCC could achieve. We received information that there are new IGCC units permitted and under construction. The EPA believes one IGCC unit under construction for which permit data were provided is representative of both current technologies and of IGCC units that will be built in the near-term future. Therefore, the EPA believes these permit levels should be the basis of the new source IGCC emission limits and the Agency is finalizing the PM and Hg limits on that basis, as that source will be required to comply with its permitted limits once constructed and it is a similar source. However, permit limits were only provided for PM and Hg; therefore, the EPA is finalizing the new source limits for acid gas HAP based on data from the best-performing of the existing IGCC units for the respective HAP.

B. Rationale for Subcategories

Many commenters stated that the EPA should have proposed more subcategories, while others believed that too many subcategories were proposed. Many different issues were raised by commenters, and some of the key issues that were considered in the final rule (some of which led to changes in the final rule) include: the technical deficiencies in the definition for the low-Btu coal subcategory; additional subcategorization of the coal-fired EGU population; the need for subcategorization of distillate vs. residual oil-fired EGUS; the need for a limited-use subcategory for EGUs that operate for only a small percentage of hours during a year; and the need for a non-continental liquid oil subcategory for island units that have limited fuel options and other unique circumstances. The comments and the EPA responses are provided below.

In general, the EPA has reviewed the data provided and continues to believe that the coal-fired EGU subcategories proposed are the only ones supported by the data, though we have revised the basis for EGUs designed to burn low rank virgin coal as discussed above. The EPA may not subcategorize by air pollution control technology type as requested by a few commenters. Further, the EPA has reviewed the other suggested coal-fired subcategories and finds no basis for further subcategorization (*e.g.,* based on boiler design, boiler size, or duty cycle).

1. Coal Subcategories

Comment: Commenters noted that although other subcategories had been evaluated, including subcategorization of other coal ranks, no other coal rank subcategorization was proposed. Commenters submit there should be subcategories for the coal ranks of bituminous, subbituminous, and lignite. The commenters noted that such treatment would be consistent with past practice (*e.g.,* CAMR where the differences in the type of emissions of Hg due to the different chemical properties of coal within differing fuel ranks was discussed). Commenters note that activated carbon has been shown to be very effective when used in combination with low chlorine coals (such as western subbituminous coals); however, activated carbons can suffer from poor performance when used with high sulfur coals. Commenters indicate that firing high sulfur coals (especially when an SCR is also used) can result in sulfur trioxide (SO_3) vapor in the flue gas stream. The SO_3 competes with Hg for binding sites on the surface of the activated carbon (or unburned carbon) and limits the effectiveness of the injected activated carbon. But another commenter noted that an SO_3 mitigation technology, such as dry sorbent injection (DSI, *e.g.,* trona or hydrated lime), applied upstream of the ACI can minimize this effect.

Commenters also stated that without further subcategorization the economic impacts on individual Midwestern states will be particularly acute as huge segments of the U.S. coal reserve will be disenfranchised by this rule. According to the commenters, the EPA did not even attempt to legitimately analyze this issue and, thus, in their opinion the Agency's proffered rationale for

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declining to further subcategorize based on the acid gas standard is belied by the record. The commenters believe that the EPA needs to better align this rule with its previous position in CAMR and further subcategorize based on coal type.

Other commenters are opposed to any further subcategorization based on coal rank. Because many sources blend several ranks of coal on a regular basis, commenters believe that establishing coal rank subcategories would create numerous opportunities for sources to game the regulations and substantially increase emissions. Commenters stated that there is no need for such an approach since modern pollution controls can accommodate a wide range of coals. These commenters believe that EGUs firing different ranks of coal are not fundamentally different in size, class, or type in a way that impacts emissions or that limits the availability of controls. The commenters believe that emissions of fuel-dependent HAP can be controlled by either changing the fuel prior to combustion or by removing the HAP from the flue gas after combustion. Commenters state that ACI systems, DSI controls, and PM controls are available for installation at units firing sub-bituminous coal and are equally available for units firing bituminous, anthracite, or lignite coal. These commenters also believe that as long as a control option is commercially available, the cost for a particular EGU is irrelevant to the EPA's development of emission standards based on MACT. Commenters stated that subcategories based on coal rank would make a meaningful consideration of fuel switching impossible, contrary to the judicial mandate to consider substitution of materials in setting the floor and the statutory mandate to consider substitution of materials in the beyond-the-floor analysis.

One commenter stated that although they previously supported the subcategorization of coal-fired units on the basis of coal rank, they no longer object to grouping units that burn bituminous and subbituminous coals in a single category because the prior basis for subcategorization no longer exists. The commenter indicated that at the time of CAMR, it was widely recognized that although coal-fired units combusting bituminous coal, with its higher concentration of chlorine and, therefore, ionic Hg, could effectively limit Hg emissions by utilizing existing control technologies such as scrubbers, units burning subbituminous coal could not do so with the same controls because of the coal's higher levels of elemental Hg. The commenter stated that activated carbon was only a fledgling and unproven technology at the time; today, however, activated carbon has been proven, and units burning bituminous and subbituminous coal can achieve the same levels of emissions for Hg and other HAP. Consequently, the commenter believes the prior basis for subcategorization no longer exists and the commenter, therefore, agrees that coal-fired EGUs burning bituminous and subbituminous coals ought to be grouped in a single category.

Response: The EPA disagrees with commenters that additional coal-fired subcategories are warranted and has not provided any in the final rule. Commenters are correct that additional subcategorization was proposed in January 2004. Whether or not such subcategorization was warranted at that time, the EPA believes that the current conditions are such that, even if appropriate at that time, such further subcategorization is not appropriate at this time.

When all of the factors noted by commenters have been reviewed, with the exception of Hg for certain units, as discussed above, the EPA does not believe that the HAP emissions to the atmosphere are sufficiently different from coal-fired EGUs to warrant further subcategorization. There are EGUs firing bituminous, subbituminous, and coal refuse among the top performing units for Hg and EGUs firing bituminous, subbituminous, lignite, and coal refuse are all among the top performers for the acid gas HAP and non-mercury metallic HAP indicating that the MACT floor limits established based on these units are achievable by units burning all ranks of coal.

As noted by commenters, ACI, not fully developed in 2004, is now able to effect Hg control levels on subbituminous coals such that similar emissions to the atmosphere may be achieved as those achieved by higher-chlorine bituminous coals when FGD systems are used or by coal refuse EGU with less controls. Thus, in looking at the total system, similar emissions to the atmosphere are achieved by all of these coal ranks. The EPA has addressed elsewhere in this document its rationale for not subcategorizing by coal chlorine content. The EPA does not believe that any fundamental discrimination between coal ranks will occur as a result of the final rule, though clearly some sources will be required to install greater controls to comply with the final standard. We maintain that such result is consistent with the intent of CAA section 112 standards, which are not intended to have an outcome whereby all sources can comply with final standards without any action.

The EPA agrees, in theory, that EGUs are designed around a basic set of coal characteristics. However, the 1999 ICR demonstrated that numerous EGUs have conducted trial burns and gained sufficient experience such that co-firing blends of various coal ranks is now common practice. In fact, the EPA believes that such blends may be modified daily, depending on the characteristics of the coal being burned and on the level of generation needed. The extent of blending, and the ability to switch the blends on short notice, does not lend itself (or, in fact, argue for) additional subcategorization.

The EPA disagrees with any assertion that the EPA ignored possible subcategorization approaches or that it has insufficient data upon which to base or evaluate various subcategories. The EPA fully examined the record, which demonstrates that coal-fired EGUs, with the exception of certain units for Hg, have similar HAP emissions profiles and that similar control approaches are available to such EGUs. Although commenters suggested additional subcategories were warranted, they failed to provide sufficient data to support their proposed alternative subcategories. As noted elsewhere, the EPA does not disagree with commenters that there are some differences in EGUs. However, the EPA does disagree with commenters that those differences result in differences in emissions to the atmosphere such that additional subcategorization is justified.

Failing to demonstrate that coal-fired EGUs are different based on emissions, the commenters turn to economic arguments, asserting that failing to subcategorize will impose an economic hardship on certain sources. Congress precluded consideration of costs in setting MACT floors, and it is not appropriate to premise subcategorization on costs either. See S. Rep No. 101–228 at 166–67 (5 Legislative History at 8506–07) (rejecting the implication that separate categories could be based on "assertions of extraordinary economic effects"); *see also NRDC* v. *EPA* 489 F.3d 1364 (D.C. Cir. 2007) (holding that EPA properly declined to create a subcategory for a particular source and rejecting the argument that the source may have to incur more costs to comply with the rule without such subcategory).

The final limits are based on EGUs currently operating with available controls. As noted above, the record shows that the various types of EGUs are represented in the floors, with the exception of certain units for Hg, which

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indicates that the levels are achievable by such units. Thus, the data actually show that the MACT standards are achievable for a wide variety of EGUs.

In addition, the EPA believes it has fulfilled the CAA section 112(c)(l) directive that "[t]o the extent practicable, the categories and subcategories listed under this subsection shall be consistent * * *" with those of CAA section 111, notwithstanding commenters assertion to the contrary. The decision on whether to directly align CAA sections 112 and 111 subcategories is discretionary and EPA has reasonably exercised its discretion in declining to create additional subcategories for coal-fired EGUs based on the record, with the exception of certain sources for Hg.

Finally, the EPA disagrees with the commenters that suggest that EPA lacks the legal authority to consider material inputs when considering subcategories. We agree, however, that material inputs must be considered when establishing MACT standards for the subcategories that are established. We also believe a meaningful consideration of fuel switching can occur even if sources are subcategorized based on fuel inputs because EPA considers fuels switching in evaluating potential beyond-the-floor alternatives.

Comment: One commenter stated that the EPA should establish an existing source acid-gas subcategory for high sulfur or high chlorine coals because the same factors that the EPA relied on to support a low rank virgin coal subcategory for Hg are also present in the high sulfur or high chlorine coal context. The commenter stated that the data indicate that even well-controlled units burning high sulfur coals would not be in the top performers for acid gases even at removal rates of 95 or 96 percent. The commenter added that absent such a subcategory, about 12 percent of coal deliveries (2005 data), and the vast majority of coal shipped from the states of Indiana, Ohio, and Illinois (2008 data), would become unusable. The commenter expressed support for the alternative SO_2 standard for units unable to meet the HCl standard; however, the commenter also believed that it is appropriate to establish a coal chlorine or sulfur content-based subcategory for the alternative SO_2 standard. The commenter stated that coal testing data indicate a clear break in chlorine concentrations in the coals burned by EGUs, as well as in sulfur content. The commenter indicated that there are factors supporting a high sulfur or high chlorine coal subcategory that are similar to those that the EPA relied upon to support a Hg subcategory for low rank virgin coal. According to the commenter, the EPA's key rationale for a Hg subcategory for low rank virgin coal was that no low rank virgin coal-fired unit appeared in the "top performing 12 percent of sources, indicating a difference in the emissions for this HAP from these types of units." The EPA did not establish other subcategories because "the data did not show any difference in the level of HAP emissions and, therefore, we have determined that it is not reasonable to establish separate emissions limits for other HAP." The commenter indicated that the EPA does not need emissions data to know that even well-controlled units burning higher sulfur coals would be unable to meet the alternative SO_2 emissions rate, and would therefore also not appear in the top 12 percent of performing units.

Response: The EPA disagrees with commenters that subcategories should be established for high sulfur and high chlorine coals. It appears from the comments that it is not in fact the chlorine content that is at issue but the sulfur content of the coal. Commenters state that they are unable to meet the HCl limit, but they only provide information indicating it would be difficult to meet the alternative equivalent SO_2 limit. In fact, our data show that coals with chloride contents as high as 2,100 ppm (0.16 lb/MMBtu) were burned by EGUs making up the MACT floor pool of sources for the final HCl emission limit and that the best-performing unit was burning coal with a maximum chloride content of 1,200 ppm. The median chloride level for bituminous coals identified from data submitted through the 1999 ICR was 1,030 ppm so we believe that the coals represented in the MACT floor pool indicate that the final limits are achievable with high-chlorine coals. We have determined that HCl removal is very effective using a number of different types of FGD systems. Absent information demonstrating that sources are unable to meet the proposed HCl limit due to the chlorine content of the coal, we believe it is unnecessary and inappropriate to consider subcategorizing based on chlorine content in the coal.

In addition, as noted above, the SO_2 limit is an alternative equivalent standard that is available to sources that have an SO_2 control and CEMS and operate the controls at all times. The EPA did not provide the alternative equivalent standard for sources that could not meet the HCl limit as one commenter suggests; instead, we provided the standard as a convenience and cost saving measure to EGUs with installed FGD systems because we recognize that many EGUs have SO_2 CEMS. Sources are required to comply with the HCl limit as a surrogate for all the acid gas HAP or the SO_2 limit as an alternate equivalent standard. Commenters have not demonstrated that they are unable to meet the HCl standard and our data show that the standard is achievable even for high chlorine coals.

Comment: Several commenters supported the development of a separate subcategory for fluidized bed combustors (FBC) or circulating fluidized bed (CFB) EGUs. The commenters encouraged the Agency to consider subcategorization of FBC EGUs for Hg emissions noting that the industry has long contended that the design, construction, and operation of FBCs are different than conventional boilers and that FBCs employ fundamentally different processes than conventional PC-fired EGUs. The selection of an FBC unit over a conventional PC boiler is driven in large part by fuel characteristics. The commenters assert that, as a result, the emissions profile of FBC units generally differ from conventional PC boilers because FBC units more advantageously combust waste coals, as well as coal blends with other carbonaceous material. The commenters stated that the EPA did not discuss the design differences between FBC units and PC units in the preamble to this proposed rule unlike what the Agency did when it previously proposed Hg MACT limits in January 2004. Commenters state that, for these reasons, FBC units can be considered a distinct type of boiler.

The commenters noted that an examination of the 40 "best performing" units for Hg emissions in the proposed MACT floor spreadsheet showed that 14 of those units are FBC units. The commenters maintained that had FBC units performed as well as conventional PC boilers, 2 units would have been expected to be in the top 40. The commenters allege that the far higher percentage of FBCs in the top 40 leads to the conclusion that these units are different from conventional PCs with regard to Hg emissions and, as a result, should have been placed in their own subcategory. Further, commenters noted that the largest FBC has a nameplate capacity of about 300 MW while the largest conventional boilers have nameplate capacities of around 1,300 MW.

The commenters stated that FBCs combust relatively large coal particles in a bed of sorbent or inert material at a lower degree of combustion efficiency.

Fluidized bed units operate at less than half of the temperature of a conventional boiler and have much longer fuel residence times. Conventional boilers pulverize coal to a very fine particle size to maximize combustion efficiency and minimize unburned carbon. As a result, the commenters noted that FBCs typically have higher levels of unburned carbon present in the ash, which behaves much like activated carbon and helps promote more efficient Hg removal. Accordingly, commenters maintain that Hg emissions of FBC boilers and PC boilers are statistically different, with emissions from FBCs significantly lower than those from PC boilers. According to commenters, this statistically significant difference in the Hg emissions profiles for these two distinct boiler technologies argues in favor of the creation of a separate subcategory for FBCs, as there is no control technology that PCs could install that would result in emissions reductions similar to those achieved by FBCs. The active quantity of calcium oxide (lime-CaO) available in a FBC boiler is also orders-of-magnitude greater than compared to a PC boiler, whose alkalinity is derived solely from the coal's mineral content. Significantly higher CaO can alter the process chemistry in the boiler, including the oxidation levels of Hg.

One commenter stated that the EPA properly declined to subcategorize units based on design type where there is no indication that any physical distinctions among unit designs have a meaningful and substantial impact on HAP emissions. The commenter indicated that it would be inappropriate to subcategorize FBCs because there is no evidence to support a determination that FBC design is responsible for a unit falling in or out of the top 12 percent for a particular HAP.

Response: The EPA acknowledges that there are design and operation differences between conventional PC-fired EGUs and FBC/CFB EGUS; however, the commenters are incorrect in asserting that the HAP emissions levels and characteristics are sufficiently distinct from other coal-fired EGUs to support subcategorization. Further, commenters fail to note that FBC EGUs were not subcategorized in CAMR even though, as commenters note, such design and operation differences were cited there. The fact that FBC units operate at lower temperatures is of no consequence as they still operate at temperatures high enough to vaporize Hg.

Commenters assert that FBC units are disproportionately represented among the best performers, with the inference being that they were selected to test in the 2010 ICR because of their boiler design. However, FBC EGUs were not specifically selected as best performers for Hg, as EPA did not select any EGUs based on a determination that they were best performers for Hg (as noted elsewhere, we had no basis for selecting EGUs as being best performers for Hg), and to the extent CFB units were selected in the 2010 ICR, they were selected because we determined they were best performers for non-mercury metallic HAP, acid gas HAP, or organic HAP or because they were randomly selected among the non-best performers for those three HAP groupings. Thus, the CFBs were selected for testing under the 2010 ICR based not on their boiler design but, rather, based on the age and on their PM and FGD control systems (as noted in the Supporting Statement for the 2010 ICR). As many FBC EGUs, including CFB EGUs, are relatively new, they were included in the non-mercury metallic HAP group selected for testing (because their PM controls were among the 175 newest), the acid gas HAP group selected for testing (because FBC was considered to be an FGD system and the units were among the 175 newest), and organic HAP testing (because they were among the newest and, thus, determined to be among the most efficient).

The effect on Hg emissions is not what commenters suggest because, although, as noted by commenters, FBC units may be found among the better performers (among the top 10 EGUs) on the Hg MACT floor spreadsheet, they are also found in the range of 221 to 226 EGUs (of 393 data points). The fact that FBC units have "vastly dissimilar ash properties" that may contain higher levels of lime or unburned carbon in the fly ash than conventional PC EGUs does not indicate that the overall system behaves any differently with regard to emissions to the atmosphere (the key metric) than a conventional PC EGU with add-on controls. The asserted higher levels of unburned carbon result in a range of effectiveness of Hg control that is similar to that of ACI found on PC EGUs; such ACI control may be found on EGUs that are among the better performers as well as on EGUs as low as 369 on the list of data points. Thus, the EPA disagrees that FBC units are disproportionately represented in the Hg floor and that their inclusion is somehow inappropriate or leads to skewing of the analysis.

All types of coal-fired EGUs other than those we subcategorized are represented in the MACT floors for Hg and all types of EGUs are represented in the floors for the non-mercury HAP. Fluidized bed combustion EGUs are not an exception and such EGUs are found across the range of top performing EGUs for all of the HAP categories: Acid gas, non-mercury metallic, and Hg. In addition, any assertion that non-FBC EGUs are unable to meet the final standards because FBC EGUs are included in the same subcategory (or vice versa) is plainly refuted by the fact that EGUs of all types are currently meeting one or more of the final standards. Thus, the EPA finds no basis for subcategorizing FBC EGUs.

Further, as noted below, the EPA does not believe there is a basis for subcategorizing small EGUs, either FBC or PC. In addition, the data have been re-evaluated based on comments received and an FBC unit is not the basis for the new source Hg MACT floor.

Comment: Many commenters stated that the EPA should have considered additional subcategorization schemes, including one based on EGU size. Commenters noted that one of the factors that the Administrator can consider under CAA section 112(d)(1) in making subcategorization decisions is unit size. Commenters stated that an analysis of the 2010 ICR data showed a statistical difference between EGUs with a capacity of 100 MW or less and EGUs above 100 MW; other commenters suggested that the cut-off range should be 125 MW. Although large in number (about 27 percent) of all EGUs, these small EGUs only comprise about 5 percent of the coal-fired capacity in the U.S. Thus, commenters assert that if different MACT limits are set for this subcategory of EGUs, it will not have a significant impact on the health effects of HAP emissions. Commenters noted that although emission rates from such small EGUs are greater than those found in the large unit fleet, their contribution to the total EGU emissions is not significant. The costs associated with coming into compliance with the proposed rule by installing new controls would be proportionally much higher for these small EGUs than larger EGUs according to the commenters. The commenters allege that this would force the retirement of generation capacity and threaten electrical reliability without appreciable benefit to the environment.

One commenter stated that in general, the nature of many public power facilities differs from the general population of coal-fired power plants. Public power units tend to be smaller in size, and are often space-constrained by growth in the community surrounding the generating unit since its initial construction. These limitations restrict the ability of these EGUs to achieve the same performance levels of larger,

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unconstrained EGUs; and, for those EGUs that can comply with the proposed standards, the installation of controls sharply increases the cost of compliance. The commenter stated that the EPA did not adequately subcategorize to accommodate many small- and medium-sized public power utilities. In particular, the EPA did not avail itself of the opportunity to use a public power electric utility subcategory, rural subcategory, or fuel type subcategories. Other commenters endorsed the establishment of a less than 100 MW subcategory that would reduce the costs of the proposed rule significantly, but only affect 5 percent of the total electric utility sector, and help minimize retirement of uneconomical plants.

One commenter stated that the EPA properly recognized that subcategories based on unit size would be inappropriate because the proposed emission limits are in terms of lb/MMBtu or lb/TBtu and noting that an EGU's total nameplate capacity is wholly unrelated to its ability to achieve the proposed limits. Another commenter opposed any proposal to subcategorize units below 100 MW. The proposed rule does not apply to units less than or equal to 25 MW, and this commenter believed that this is a sufficient threshold for applicability.

One commenter stated that the EPA could establish subcategories for the purpose of temporarily exempting, for example, a subcategory of utilities that meet the definition of small entity for purposes of the proposed rule. The temporary exemption would sunset on a date certain (e.g., 3 years from the effective date of the rule) at which point the sources in the subcategory would become subject to the rule, and a compliance timetable would start to run. The commenter believed that this time-staged promulgation and compliance proposal would greatly increase the chance that the control measures could be added in an orderly and efficient manner with minimal disruption to power markets and grid reliability.

Response: The EPA agrees with commenters who stated that an EGU's size is totally unrelated to its ability to comply with the final concentration-based limits. The EPA examined the size of units within the respective MACT floor pools of sources and found units ranging in size from 25 to 1,320 MW in the HCl floor pool, from 25 to 869 MW in the non-mercury metallic floor pool, and from 47 to 544 MW in the Hg floor pool. Thus, we find no more difference between a 25 MW EGU and (e.g.) a 500 MW EGU than we do between a 500 MW EGU and a 1,300 MW EGU and reaffirm our position that the MW capacity of the EGU is not a determining factor in its emissions. Further, the EPA believes that units of all sizes are owned by both large and small entities.

The EPA examined the effect if EGUs less than 125 MW were subcategorized for Hg. The resultant MACT floor for these EGUs would be 1.0 lb/TBtu on a 30-boiler operating day rolling average, a level more stringent than that developed for the >8,300 Btu subcategory as a whole. We do not believe that this is what commenters envisioned when suggesting such a subcategory but we believe it confirms our analysis of the data that indicates, as noted, these units are controlled in the same manner as other, larger EGUs, such that additional subcategorization is not necessary or reasonable. Further, based on the number of EGUs less than 125 MW in the HCl and PM MACT floor pools, we believe that a similar analysis for HCl and PM would lead to similar or more stringent standards than without the additional subcategory. Thus, units of all sizes are capable of achieving the proposed limits and the EPA is not finalizing a subcategory based on unit size in the final rule.

The CAA authorizes EPA to subcategorize based on "classes, types, and sizes of sources." The EPA does not believe that this provision permits subcategorizing sources based solely on their status as small entities for several reasons. As a threshold matter, commenters provided no information to suggest that EGUs at small entities are different from EGUs owned by other entities. Instead, the commenters' justification for such a subcategory was that the costs to comply with the standards make it more difficult for small entities; thus, the basis is essentially a cost basis and we do not think that is consistent with the statute. Moreover, the legislative history of CAA section 112(d) supports EPA's interpretation that subcategories cannot be based on the cost of compliance. *See* S. Rep No. 101–228 at 166–67 (5 Legislative History at 8506–07) (rejecting the implication that separate categories could be based on "assertions of extraordinary economic effects").

In addition, the EGUs owned by small entities use the same type of fuel as other units, have the same type of combustor designs, and can use the same types of controls, and so there is no difference in the HAP emissions from such units. So, even if we believed a subcategory based on small entities was consistent with the statute, we would decline to include such a subcategory.

Therefore, given the language of CAA section 112(d), the legislative history, and the available information, EPA is not creating a separate subcategory for EGUs owned by small entities.

In addition, the D.C. Circuit has clearly stated that the EPA does not have the statutory authority under CAA section 112 to extend compliance dates past the 3-year maximum compliance time authorized in CAA section 112(i)(3)(A) except consistent with CAA sections 112(i)(3)(B) and 112(i)(4). *See NRDC* v. *EPA,* 489 F.3d 1364, 1374 (D.C. Cir. 2007) (finding that "Congress enumerated specific exceptions to the 3-year maximum, which indicates that Congress has spoken on the question and has not provided the EPA with authority under subsection 112(i)(3)(B) to extend the compliance date * * *") (citing also CAA section 112(i)(4)). The EPA may not alter the compliance date based on size or ownership considerations and, thus, we are not providing a separate compliance date for different groups of EGUs in the final rule.

Comment: One commenter stated that the EPA should establish a subcategory consisting of EGUs that had received air construction permits but had not yet commenced construction as of the date of the EPA's proposed rule. The commenter believed that such a category would be justified because a substantial amount of time, money, and effort has been invested in these units. The commenter asserted that imposing new source standards on these EGUs for which the EPA's proposed rule had not been anticipated during their permit consideration would unreasonably and arbitrarily impose additional costs and burdens on these projects and would likely threaten the viability of many of them. The standards for this subcategory would be based on the anticipated performance of these units (as reflected by the permitted case-by-case emission levels), ensuring a reasonable and appropriate level of HAP control without unreasonably and arbitrarily interfering with the development of these units.

Response: Clean Air Act section 112(a)(4) defines a new source as "a stationary source the construction or reconstruction of which is commenced after the Administrator first proposes regulations under this section establishing an emission standard applicable to such source." The EPA's regulations implementing the CAA section 112 General Provisions define "commenced" to mean "with respect to construction or reconstruction of an

affected source, that an owner or operator has undertaken a continuous program of construction or reconstruction or that an owner or operator has entered into a contractual obligation to undertake and complete, within a reasonable time, a continuous program of construction or reconstruction." *See* 40 CFR 63.2.

The EPA is constrained by the definition of "new source" such that any source that "commenced" construction after the May 3, 2011, proposal date is considered a new source under the statute and the source must comply with the new source standards even if the source received a final and legally effective CAA section 112(g) permit before proposal. It is unclear from the comments whether the sources identified in the comments have commenced construction as defined in the regulations; however, the identified sources are existing sources, not new sources, under the final rule if construction was commenced prior to the proposal date.

Under the final rule, new sources must comply with the standards on the date of promulgation or at startup, whichever is earlier, and existing sources have 3 years to come into compliance with the final standards. Pursuant to the EPA's regulations at 40 CFR 63.44(b)(1), however, we may provide in a final CAA section 112(d) standard a specific compliance date for those sources that obtained a final and legally effective CAA section 112(g) case-by-case MACT standard and submitted the information required by 40 CFR 63.43 to the Agency before the close of the comment period. The EPA does not believe it has received such information during the comment period and we are not establishing a separate specific compliance period for sources that obtained final and legally effective CAA section 112(g) standards prior to promulgation of the final rule. In the absence of EPA action on this issue, state Title V permitting authorities are required to "establish a compliance date in the [title V] permit that assures that the owner or operator shall comply with the promulgated standard [ ] as expeditiously as practicable, but not longer than 8 years after such standard is promulgated * * *" 40 CFR 63.44(b)(2). Sources with final and legally effective section 112(g) standards should work with their permitting authorities to determine the appropriate compliance date consistent with the EPA regulations.

Comment: One commenter stated that in accordance with CAA section 112(d)(l), based on the government-to-government relationship of the Navajo Nation and the U.S. government, and consistent with the right of sovereignty and self-determination of the Navajo Nation, it may be appropriate to classify EGUs on tribal lands in a different subcategory from those on non-Indian lands. The commenter stated that in accordance with the distinctive status of Indian lands, based on principles of tribal sovereignty and self-determination, the government-to-government relationship, and the flexibility of federal agencies mandated under E.O. 13175, the EPA should classify sources on tribal lands as a unique subcategory of EGUs for which emission standards for NESHAP should be set pursuant to CAA section 112(d)(3).

Response: Pursuant to CAA section 112(d)(1), the EPA may subcategorize sources based on differences in class, type, or size. In the preamble to the proposed rule, the EPA further explains that any basis for subcategorizing (*e.g.*, class) must be related to an effect on emissions, rather than some difference which does not affect emissions performance. The EPA does not agree that a subcategory based on location on Tribal lands is consistent with the statutory authority to subcategorize, and commenters do not explain why emissions would be different for EGUs located on Tribal lands. Absent that showing, EPA believes it would not be appropriate to subcategorize units even if we believed such a subcategory is consistent with the statute. CAA section 112 imposes specific requirements with respect to the methodology that the EPA must use in establishing emission standards for HAP, including Hg emissions from EGUs. Pursuant to CAA section 112(d)(1), the EPA may subcategorize sources based on differences in class, type, or size. The EPA believes, that any basis for subcategorizing (*e.g.*, class) must be related to an effect on emissions, rather than some difference which does not affect emissions performance.

However, the EPA is sensitive to the commenters' concerns and particularly recognizes the significance of Navajo Generating Station to the Central Arizona Project and the water delivery to tribes. As a result, EPA has been consulting with affected Indian tribes and working closely with other federal agencies, including the Department of the Interior, on these issues and intends to work with tribal and other authorities to ensure a smooth transition and address specific issues as they arise.

2. Oil Subcategories

Comment: Several commenters stated that distillate oil, and in particular ultra-low sulfur diesel (ULSD) oil, has fuel characteristics closer to that of pipeline gas than to residual oils. The metals, as well as the ash and nitrogen content, of distillate oils are very low, and the sulfur content of ULSD is approximately the same as that of pipeline natural gas. The commenters state that distillate oil is a more refined product than residual oil and, thus, burns cleaner. According to commenters, separating liquid oil-fired EGUs into two subcategories (distillate and residual oil) would be consistent with the discussion of subcategory differentiation in the rule's preamble which indicates that the division of a category into subcategories is justified if the two subcategories have very different emissions, which is true for distillate vs. residual oils. Distillate and residual oils are also differentiated by their operating requirements. Some commenters stated that as a consequence of the mechanical differences between boilers designed for residual oil vs. distillate oils, and between the fuel-handling requirements for the different fuels, it is not possible to interchange oil types without significant modifications to the oil storage tanks, transfer pumps, piping and valves, flow control systems, burners, and burner control systems. Commenters also noted that some of the EGUs in the EPA's liquid oil-fired database were mischaracterized with regard to the type of oil burned during the 2010 ICR testing.

Some commenters alleged that by combining distillate and residual oil into a single MACT category, the resultant MACT standards cannot be satisfied by a boiler firing residual oil without substantial add-on controls. The commenters asserted that creation of separate subcategories for liquid oil-fired units that distinguish between residual and distilled oil would render the standards more achievable for distinct subcategories of EGUs and reduce the number of potential plant closures while still advancing the goal of reducing overall emissions. These commenters contend that MACT floors should not be used to eliminate whole classes of existing EGUs through mathematical floor calculations based on data from uncontrolled units and combining boiler subcategories that are not capable of accommodating a different fuel.

One commenter stated that the EPA should not subcategorize liquid oil-fired EGUs based upon different grades of liquid oil. Although different grades of liquid oil may vary in their heat contents or viscosities, the commenter maintained that there is no indication in the rulemaking record that any physical

distinction among units burning different grades of liquid oil affects the nature or characteristics of emissions in a way that impacts the availability of controls. According to the commenter, both distillate and residual oil-fired units can apply similar control technologies to reduce HAP emissions, and EGUs firing these fuels do not have physical distinctions that prevent controls from operating effectively. The commenter believes that fuel switching is an appropriate control technology and is available for liquid oil-fired sources. Residual fuel oil contains higher levels of contaminants, including HAP, than distillate oil, and because a regulated entity can readily burn cleaner distillate oil in lieu of residual oil, it is inappropriate to subcategorize based on the distillation fraction of the liquid oil. Thus, according to the commenter, the grade of liquid-oil fuel does not provide a reasonable basis for subcategorizing various groups of liquid oil-fired EGUs. Another commenter alleges that the EPA did not list distillate oil-fired EGUs in the 2000 Finding.

Response: The EPA has reviewed the data and determined that it is not necessary to subcategorize distillate vs. residual oil. Commenters had noted that the EPA's MACT Floor Analysis spreadsheet at proposal had erroneously assigned the oil type used during testing for some boilers. The EPA reviewed the data and determined that the submitting companies had entered the data incorrectly, or had indicated that two types of oil were fired in different parts of the 2010 ICR responses. The EPA contacted all of the companies with oil-fired EGUs in the 2010 ICR to confirm the oil used during testing. Upon review of these data, it became apparent that units using residual oil with ESPs or distillate oil without control were the best-performing oil-fired EGUs for PM and the HAP metals. Further, although emissions of HAP from distillate oil-fired EGUs are generally lower than those from residual oil-fired EGUs, EGUs burning distillate oil appeared to have higher emissions of some HAP but lower emissions of others.

In addition, the EPA does not agree that distillate oil-fired EGUs were not listed in the 2000 Finding. We believe it is inappropriate to exclude distillate oil-fired EGUs from regulation under the final rule because the Agency did not make a distinction when listing the oil-fired units.

The EPA also disagrees with commenters that by providing the distillate vs. residual oil subcategories as requested, the resultant standards would be more achievable. Were the EPA to subcategorize distillate oil from residual oil, the users of distillate oil would have no means of compliance other than obtaining "compliance" oil from their distributor (which was not indicated as an option by any commenter) or converting to natural gas and being removed from the subcategory. With no further subcategorization, oil-fired EGUs have the option of installing an ESP or converting to distillate oil for compliance. Commenters did not contend that it was impossible to convert to distillate oil, only that it would require plant modifications. Installing controls would also require plant modifications so sources will be able to evaluate the options and determine the most cost-effective option to comply with the final rule. CAA section 112 is intended to be a technology-forcing statute, and, because both distillate oil- and residual oil-fired EGUs were among the best performing sources in the floor and both types are meeting the final standards, we cannot reasonably conclude that the HAP emissions characteristics of these similar types of units are distinct. Therefore, the EPA is not establishing separate subcategories for distillate and residual oil-fired units in the final rule.

3. Limited-Use Subcategory

Comment: Several commenters stated that EPA should establish a limited-use subcategory for liquid oil-fired EGUs that are required to burn oil during periods of natural gas curtailment. One commenter stated that under New York State Reliability Council Rules, their facility is required by the New York Independent System Operator (NYISO), for reliability purposes, to maintain the capability to burn oil and actually burn oil, from time to time, at varying load levels to help avoid or avert potential natural gas shortages in New York City. The requirements to burn oil under this program are mandatory and are not within the commenter's discretion. The reliability rules require that the commenter's EGUs maintain their co-firing capability to respond to unplanned, emergency scenarios by operating on oil during required minimum oil burn periods, typically 25 percent oil/75 percent natural gas. The commenter noted that operation using oil at other times or on 100 percent oil during reliability operation periods occurs very infrequently; with natural gas expected to become more available in future years, such an operating scenario will become less likely. However, while the reliability rules remain in place and commenter's boilers are required to operate under his regimen, the commenter believed that it is essential that it be able to do so.

Other commenters noted that requiring installation of emission controls on oil-fired units that operate at a 10 percent oil-fired capacity factor or less is nonsensical and will result in little environmental benefit. Commenters contend that low-capacity factor units emit significantly less HAP than even well-controlled oil-fired units with much higher capacity factors. In addition, commenters allege that stack-testing at such units would be equally impractical and, in addition, would likely require the unit to operate on oil (and emit HAP just for the test) when it would otherwise be off-line or operating on natural gas.

Response: As stated above, after considering comments received, we are establishing a limited-use subcategory for liquid oil-fired EGUs with an annual fired capacity factor of less than 8 percent averaged over each 24-month block period after the compliance date.

At proposal, we solicited comment on establishing a limited-use subcategory for liquid oil-fired EGUs:

> EPA is also considering a limited-use subcategory to account for liquid oil-fired units that only operate a limited amount of time per year on oil and are inoperative the remainder of the year. Such units could have specific emission limitations, reduced monitoring requirements (limited operation may preclude the ability to conduct stack testing), or be held to the same emission limitations (which could be met through fuel sampling) as other liquid oil-fired units. EPA solicits comment on all of these proposed subcategorization approaches.

As stated above, the EPA did not have sufficient information on limited-use liquid oil-fired EGUs upon which to base a subcategory at proposal. Some sources required to test under the ICR did not submit the data until after proposal. Commenters indicated that their units are different because many of them are only called to service to address reliability issues associated with, for example, natural gas curtailments. The commenters further indicated that their units are different because of the generally infrequent use and the sporadic, and at times frequent, start-up and shutdown periods (*e.g.*, they are often only required to run for a couple of hours). These factors would lead to differences in the emissions characteristics for these units such that a numeric standard based on base load units would not likely be achievable during the very limited times that these limited use oil-fired units operate.

Based on comments received and our own analysis, we are finalizing a subcategory for limited-use liquid oil-

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fired EGUs as indicated elsewhere in this preamble. We find that these units constitute a different class and type of units because they are generally only used to address reliability issues associated with, for example, natural gas curtailments, and because they in fact only run for very limited periods in a year on a seasonal basis.

Although some commenters indicated a prevalence of natural gas/oil co-fired EGUs, the EPA also understands that there are other liquid oil-fired EGUs that do not co-fire natural gas but that could be subject to mandatory operation during periods of natural gas curtailment in their operating area if sufficient non-natural gas capacity is not available. Based on a review of units that report oil use to EPA, in 2010 there were 228 liquid oil-fired EGUs with a capacity factor of less than 5 percent and an additional 10 units with a capacity factor of between 5 percent and 10 percent. Only 2 of these units have capacity factors between 5 percent and 8 percent. This subcategory applies only to oil-fired EGUs that operate on oil alone and act as peaking units, as they generally address reliability issues. We are establishing the capacity factor threshold of 8 percent averaged over each 24-month block period after the compliance date.[320] In addition, as discussed below, we are establishing work practice standard for this subcategory in lieu of numeric emission standards.

Commenters that requested a subcategory for these units noted the dichotomy of establishing a NESHAP to reduce emissions of HAP to the environment while at the same time requiring an EGU to run for the sole purpose of conducting emissions testing and thereby emitting those same HAP. Because the operation of these units is infrequent and unpredictable, performing testing to demonstrate that emission limits are being met requires the sources to be scheduled to be operated merely for the purpose of performing testing. We realize that similar situations occurred in the gathering of emissions data through the 2010 ICR. However, unlike the case of one-time testing on a limited number of these units, such testing would be mandatory on a yearly basis for all of the EGUs upon the effective date of the final rule. Because requiring testing under this rule would in many cases require operators of these EGUs to schedule operation of these EGUs at times they would not otherwise run, it would result in both extra cost related to the testing as well as extra emissions; therefore, the Agency believes that it is technically and economically impracticable to monitor emissions for these EGUs, and that they should be subject to work practice standards that would not require emissions monitoring.

The annual average capacity factor would be calculated on a 24-month block period, commencing with the compliance date of the final rule. For example, assuming a March 1, 2015, compliance date, the first 24-month block would commence on March 1, 2015, and end on February 28, 2017, with the next 24-month block averaging period commencing on March 1, 2017. We believe the 24-month averaging period is reasonable to account for the fact that units needed to address reliability issues (e.g., natural gas curtailment periods) will be called to service sporadically. A 24-month averaging period provides flexibility to ensure that these units can run if there are large periods when natural gas is unavailable. As explained above, the data shows that most of these units operate for less than 8 percent of the time, and in fact it is usually less than 5 percent. Therefore, when considering whether these units would be able to perform stack testing, in many cases this will be for units that in fact operate significantly less than 8 percent of the time. In these cases, the EPA does not want to require the units to operate more just for the purpose of running a stack test resulting in additional pollution and cost. With projections for rising oil prices relative to natural gas prices, we expect this trend to continue. Liquid oil-fired EGUs subject to this subcategory would be required to conduct the same initial and periodic tune-up as all other affected units, but would have no other emission limit or work practice requirements.

Although the EPA believes that the ability to burn oil up to 8 percent of the time should address concerns about units that may need to operate using oil during gas curtailments. The EPA recognizes that if there were a period where gas use was more severely limited, such units might need the flexibility to operate for more than 8 percent in one year and less in the next, which is why we are providing the 2-year period; however based on the data we do not think EGUs in this subcategory will exceed even the 5 percent capacity factor that the data indicate is the average level for these sources.

4. Non-Continental Units

Comment: Commenters from affected island EGUs requested that non-continental EGUs be subcategorized from continental EGUs based on their lack of access to natural gas. The commenters urged the EPA to include a "non-continental liquid oil" subcategory in the final rule. According to the commenters, establishing a subcategory for non-continental units is consistent with the approach the EPA has taken in past rulemakings, including the final Industrial Boiler NESHAP. Non-continental EGUs have little or no access to natural gas, minimal control over the quality of available fuel, and disproportionately high operational and maintenance costs. All oil-fired EGUs operating in Hawaii, Guam, and Puerto Rico combust residual fuel oil exclusively and all are limited by the crude slates of their fuel suppliers. Island utilities can contract with suppliers for certain fuel specifications, such as sulfur content, pour point, flash point, API gravity and viscosity, which the refiners are able to meet primarily by blending and some sulfur removal during the refining process. However, the commenters state that the suppliers do not and cannot economically control for metal content. The crude slate feeding the refinery determines the HAP metal content of the residual oil produced according to the commenters. Because island utilities are dependent on local sources of fuel, they are equally limited by these factors.

Two commenters believe that the separate non-continental subcategory should be expanded to include continental areas that are not interconnected with other utilities and have limited compliance options due to remote locations (*e.g.*, Alaska).

Response: The EPA agrees that the unique considerations faced by non-continental EGUs warrant a separate subcategory for these units and the data show that the difference in location causes a difference in emissions apparently due to the fuel that is available for such units; thus, the Agency has included such a subcategory in the final rule. At proposal, the EPA did not have all of the data from liquid oil-fired units in non-continental areas (*e.g.*, Guam, Puerto Rico) and solicited comment on whether a subcategory should be established, based on the data to be received, for non-continental oil-fired EGUs. The EPA has now received these late data and, based on those data, is finalizing a non-continental subcategory for liquid oil-fired EGUs in Guam, Hawaii, Puerto Rico, and the U.S. Virgin Islands. The EPA is not aware of

[320] Units that co-fire oil and natural gas where the oil combustion comprises 10 percent or less of the capacity factor are natural gas-fired EGUs that are not subject to this final rule.

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any liquid oil-fired EGUs in any of the other U.S. territories that meet the CAA section 112(a)(8) definition but, if there are such units, they would also be part of the non-continental subcategory.

The EPA agrees that the unique considerations faced by non-continental refineries, including a limited ability to obtain alternative fuels that lead to different emissions characteristics, warrant a separate subcategory for these EGUs. The EPA believes that units in this subcategory will comply through the use of cleaner oils or, for PM, through the installation of an ESP. The EPA finds no merit in the comment that Alaska should be included in this non-continental subcategory because utilities in Alaska are not faced with the same access issues affecting island-based facilities.

C. Surrogacy

1. Filterable PM vs. Total PM

Comment: Numerous commenters strongly objected to the use of total PM as the surrogate standard for non-mercury HAP metals. They argued that filterable PM is a better surrogate, especially given EPA's intent to use a PM CEMS for continuous compliance demonstration. Other commenters argued that we should not use a surrogate and instead should require direct compliance with a non-mercury HAP metals standard.

Response: We have decided to use a filterable PM limit for the PM surrogate emission limit in the final rule.

Although the objective of the emission limits we are establishing is to reduce the risks associated with HAP emissions, the limits are based in part upon the demonstrated capabilities of control technologies which are installed on existing sources. Except for Hg, the best PM controls provide the best controls of metal emissions. Emissions measurements of either filterable particulate, total particulate, individual metals, or total metals provide comparable indications that the best level of control is achieved. We can find no significant difference in the emissions that would be achieved by using any one of these emissions measurements.

We re-assessed the relationships between individual metal emissions, filterable PM emissions, total PM emissions, and total $PM_{2.5}$ emissions based on the test results provided through part III of the 2010 ICR. We compared the measured emissions of metals and PM with the uncontrolled emissions estimates and found that control of PM was indicative of the control of metals emissions. In addition, we compared the correlations associated with non-mercury HAP metal emissions and the three forms of PM and found that no specific particulate form provided a consistently superior indicator of better metals control. Although control of filterable PM provided the best indicator of performance for control of some HAP metals, control of total particulate or total $PM_{2.5}$ was nearly as good as an indicator. For control of other HAP metals, total PM measurement provided the best indicator of control performance because it included the vapor-phase metal HAP, although, measurement of the control of filterable particulate was nearly as good an indicator. In addition, certain data analyzed by our Office of Research and Development indicate that a vapor-phase metal, such as Se, can be present as an acid gas and reduced significantly using acid gas technologies (wet and dry scrubbing). Given that the rule also provides for acid gas control monitoring, and the general equivalency of the different indicators, we have concluded that use of a filterable PM limit as the PM surrogate emission limit is appropriate.

2. Moisture Content of Oil

Comment: A number of commenters stated that studies suggest that chloride in fuel oil can result from contamination during transportation and processing of crude oils and then be emitted as HCl during combustion. For example, the commenters asserted that the chloride contamination of crude oils can occur as a result of the ballasting of tanker ships with seawater. However, the Oil Pollution Act of 1990 requires all new oil tankers to be double hulled and establishes a phase out schedule (by the middle of the decade) for existing single hulled tankers with un-segregated ballasts. Because of the role of seawater contamination in introducing contaminants into the oil, the commenters suggest that the EPA set a percent water content limit for fuel oil at a level of 1.0 percent, rather than setting HCl and HF emissions limits. This would encourage handling and transport practices to limit salt water contamination. One commenter recommended a standard of 1.0 percent water because several of the lowest HCl and HF emitting units currently require percent water (or water and sediment) specifications between 0.5 percent and 1.0 percent.

Response: The EPA is providing the alternative compliance assurance approaches in the final rule for liquid oil-fired EGUs of demonstrating compliance through either specific HCl or HF measurements or by demonstrating that the moisture content in the fuel oil remains at a level no more than 1.0 percent.

The EPA is not aware of any FGD systems installed on oil-fired EGUs. Thus, it is only the quality of the oil, and the level of HAP constituents contained therein, that can be relied upon for ensuring compliance.

In the proposal preamble, we stated:

> We believe that chlorine may not be a compound generally expected to be present in oil. The ICR data that we have received suggests that in at least some oil, it is in fact present. EPA requests comment on whether chlorine would be expected to be a contaminant in oil and if not, why it is appearing in the ICR data. To the extent it would not be expected, we are taking comment on the appropriateness of an HCl limit. *See* 76 FR 25045.

Commenters refer to certain studies that provide a plausible reason for the chloride/fluoride contamination of fuel oils. We found this reason persuasive and accordingly are providing alternative compliance approaches in the final rule to demonstrate compliance with the acid gas HAP standards. Specifically, sources can demonstrate compliance through either specific HCl or HF measurements or by demonstrating that the moisture content in the fuel oil remains at a level no more than 1.0 percent.

D. Area Sources

Comment: Numerous comments were received both in support of and in opposition to the establishment of generally available control technology (GACT) standards for area source EGUs.

Several commenters in opposition to area source standards stated that the EPA properly established emissions limitations based upon the performance of all EGUs, rather than distinguishing between major sources and area sources. The commenters believe that Congress did not intend the EPA to distinguish between "major source" EGUs and "area source" EGUs in determining whether and how to regulate EGUs under CAA section 112. These commenters indicated that differentiating major source and area source EGUs for purposes of setting emissions standards is inappropriate in light of the 2000 Finding regarding the threat posed by the absence of regulation of HAP emissions from EGUs. The 2000 Finding was based upon studies whose conclusions regarding the impacts from EGU emissions did not depend upon any relevant distinction between major source and area source EGUs. The commenters note that segregating "major source" and "area source" EGUs

would have the perverse effect of eliminating some of the best performing sources from the MACT pool of sources that constitute the "best performing" 12 percent. Many of the best performing sources have employed control technology that brings their emissions below the major source threshold, despite the fact that they are larger units. As a result, the commenters believe that if the EPA created standards for "major source" EGUs based only upon those units, the MACT standards for "major source" EGUs would be less stringent for each of the pollutants than proposed in this Rule. At the same time, the less polluting sources, the "area source" EGUs, could face limits more stringent than those proposed in the Rule. Commenters also note that after reviewing the substantial record in this rulemaking, they believe that the EPA has correctly determined that major and area source EGUs greater than 25 MW have similar HAP emissions and use the same control technologies and techniques to reduce HAP emissions. Thus, the commenters asserted that the record demonstrates that there is no technical basis for distinguishing between major and area source EGUs for purposes of establishing HAP emission control standards under CAA section 112(d).

Many commenters in support of an area source designation for EGUs stated that the EPA has promulgated area source limits for many source categories of HAP emissions, including most recently industrial boilers and note that GACT controls have been used successfully in many other EPA MACT rules, including rules for iron & steel foundries, electric arc steelmaking, coatings operations, clay ceramics manufacturing, glass manufacturing, and secondary nonferrous metals manufacturing, in order to reduce costs and regulatory burdens. The commenters state that Congress has given the EPA the ability to subcategorize area sources because of their low HAP emissions and low potential impact on human health and that, contrary to the plain language of CAA section 112 and its legislative history, the EPA made no attempt in the proposed rule to distinguish between major sources and area sources for purposes of listing or setting standards. The commenters indicated that where Congress was concerned about the health impacts of specific pollutants from specific sources, it knew how to specify that MACT limits be promulgated (*e.g.*, CAA section 112(c)(6)). The commenters state that area source rules would lessen the regulatory burden of a CAA section 112 EGU rule on many small entities (arguing that many EGUs owned by small public power entities are area sources) and that as many as 12 percent of the EGU population could qualify as area sources. A number of commenters pointed out that the small entity representatives (SER) on the SBREFA panel suggested that the EPA establish separate emission standards for EGUs located at area sources of HAP and that the standards be based on GACT as allowed under CAA section 112(d)(5). Specifically, the SERs recommended that the EPA establish management practice standards for area source EGUs.

Response: The EPA is not establishing an area vs. major source distinction in the final rule.

The CAA section 112(a)(8) definition of EGU does not distinguish between major and area sources, and we maintain that EGUs are a single source category that contains both major and area sources. The EPA proposed to regulate five subcategories of EGUs without distinguishing between major and area sources for purposes of establishing the standards for the different subcategories. Our approach is wholly consistent with the statutory definition of EGU and reasonable.

Nevertheless, the Agency did examine whether to set separate standards for area source EGUs, because we do not believe that the statute prohibits the Agency from exercising its discretion to establish GACT standards for area sources pursuant to CAA section 112(d)(5) if we determine such standards are appropriate. The EPA is not required, however, to establish GACT standards for area sources, and we believe it may even be unreasonable to do so under the circumstances we identified in the proposed rule as supported by the record of this final rule.

At proposal, we determined that it was not appropriate to establish separate standards for major and area source EGUs, and even if we had exercised our discretion to set separate standards, we would have likely declined to exercise our discretion to set GACT standards for area source EGUs given our appropriate and necessary finding and the fact that a potentially large number of area source EGUs are in fact large well controlled units.

Some commenters note that there could be as many as 12 percent of the total population that could be classified as area sources. We are not sure of the commenters' point in regard to this statement. As to commenters' statements that many of the area sources are municipal utilities, our information shows that many rather large EGUs (*e.g.*, hundreds of MW) are also area sources, and the commenters have not provided any justification for establishing GACT standards for large synthetic area sources.

Commenters did not provide an evaluation of the health and environmental impacts of the area sources and simply presume that the risks from such sources are lower, even though many of the same commenters noted that these smaller EGUs are often located in densely populated areas where populations are more likely to have adverse health effects from the HAP emissions. Furthermore, other commenters, including some industry commenters, noted that the vast majority of these potential area sources meet the criteria due to the installation of emission controls installed to meet other requirements. According to these commenters, these synthetic area sources would likely be able to meet the limits of this rulemaking and imposition of this rule would not appear to result in the installation of additional controls in a number of cases. We do not know if this assertion is correct but we determined approximately 69 coal-fired EGUs will be able to meet the existing source MACT standards with their current control configuration (out of 252 EGUs that reported data for Hg, PM, and HCl in the 2010 ICR).

Commenters also note that the Agency has exercised its discretion in other NESHAP rulemakings to establish area source limits. Although true, the fact that the EPA has established area source limits in some source categories is irrelevant to similar decisions for different source categories. Commenters have not shown that the circumstances applicable to those other source categories are similar to the circumstances identified for major and area source EGUs (*e.g.*, similar controls, similar emission characteristics, large number of synthetic minor area sources). Further, those other source categories are not statutorily defined in a manner that includes both area and major sources. EGUs are the only source category defined in CAA section 112 and, in establishing the definition of an "electric utility steam generating unit" under CAA section 112(a)(8), Congress included in the EGU source category both area and major sources. Thus, it is reasonable to regulate the EGU category in the manner Congress defined the category. Commenters have provided no legal support for the contention that the EPA must regulate area and major sources in the same category in separate rulemakings, and the EPA has in fact regulated both major and area sources in

the same rulemaking even absent a statutory definition that includes both major and area sources. (*See* National Emission Standards for Hazardous Air Pollutants From the Portland Cement Manufacturing Industry and Standards of Performance for Portland Cement Plants; 75 FR 54970; September 9, 2010.)

The EPA considered the totality of the circumstances when determining whether to set separate area and major source standards for EGUs and also considered whether it would be reasonable to establish GACT standards for areas sources. We reasonably considered whether emissions characteristics of major and area sources are different when determining whether to establish GACT standards, notwithstanding commenters' assertion that such consideration is not correct. That we also consider emission characteristics in subcategorization decisions is of no consequence for area source decisions. Given that the statutory definition of EGUs contains both major and area sources, it was reasonable to evaluate whether there were sufficient differences between area and major sources when deciding whether to exercise our discretion to set separate area and major source standards.

In addition, we find commenter's point concerning CAA section 112(c)(6) odd because EGUs emit several of the CAA section 112(c)(6) HAP (*e.g.,* lead, Hg). Although EGUs were exempted from that provision, the fact that they emit some of the HAP called out for MACT control supports our decision to not establish GACT standards for any EGUs. CAA section 112(d)(5) leaves it to the Agency's discretion to determine whether GACT standards should be established for area sources, and the statute does not require GACT standards or even indicate that such standards are to be the default regulatory approach for area sources. *See* 76 FR 25021. Instead, the statute provides the Agency with discretion and we have exercised it reasonably in this case.

Commenters indicate that many EGUs owned by small entities are potential area sources. However, commenters fail to note that there are also EGUs owned by small entities that are not potential area sources, and, thus, would not accrue any "lessened regulatory burden" benefit from a decision by the EPA to establish area source standards.

Some commenters state that the EPA's mere assertion that there would be no difference between GACT and MACT to justify an area source finding does not provide sufficient documentation for the decision. But EPA did not say there would be no difference between MACT and GACT. Instead, it stated that it would be difficult to make a distinction given the similarities between the EGUs and major and area source facilities. Specifically, as noted by other commenters, and observable by a review of the MACT Floor Analysis spreadsheets, potential area sources range in size from units near the CAA section 112(a)(8) defined lower size limit to units of hundreds of megawatts. Further, these larger area source units are, for the most part, controlled with the full suite of emission control technologies available (*e.g.,* fabric filters, scrubbers).

In addition, the data that were available in the docket for the proposed rule show that there is little difference between major and area source EGUs individually, and that generally the driver for whether a utility facility is a major or area source depends on the number of EGUs located at a facility (almost exclusively one or two EGUs located at area sources), not on any inherent difference between the EGUs themselves. *See* "Evaluation of Area Source EGUs" TSD, Docket EPA–HQ–OAR–2009–0234. In fact there are a number of EGUs that are quite large that are area sources and others that are small that are major sources. *Id.* This is the case because the acid gas HAP emissions are what drive EGUs to have HAP emissions exceeding the major source threshold. With a few exceptions, the EGUs located at area sources have FGD or other acid gas controls that reduce the acid gas HAP to area source levels. *Id.* Thus, the majority of sources that currently qualify as area sources were, in fact, major sources prior to installing controls. The exceptions are those units that would likely be able to achieve the MACT level of control for acid gas with minimal use of DSI at a reasonable cost. *Id.*

In addition, the data show that a number of area sources for which we have data are high emitters of Hg and non-Hg metal HAP. *Id.* Pursuant to our appropriate and necessary finding, these HAP pose a significant threat to human health. Thus, even were we to distinguish between major and area sources, which we do not believe is appropriate given the similarities between such sources, we would still decline to set GACT standards, and as such we maintain that MACT standards are appropriate. Moreover, for acid gas HAP, as discussed above, the data indicate that the level of control would likely be the same even if we did establish GACT standards under CAA section 112(d)(5).

We fully evaluated the nature of EGUs, and we do not see a basis on which to distinguish these sources for purposes of setting standards. Thus, we maintain that we reasonably exercised the discretion afforded the Agency under the statute and declined to set separate standards for area source EGUs.

E. Health-Based Emission Limits

Comment: Many commenters noted that in the proposed rule the EPA considered whether it was appropriate to exercise its discretionary authority to establish health-based emission limits (HBEL) under CAA section 112(d)(4) for HCl and other acid gases and proposed not to adopt such limits, citing, among other things, information gaps regarding facility-specific emissions of acid gases, co-located sources of acid gases and their cumulative impacts, potential environmental impacts of acid gases, and the significant co-benefits estimated from the adoption of the conventional MACT standard. Comments were received both supporting this position and refuting it. Several commenters suggested legal, regulatory and scientific reasons for why HBEL for HCl might be appropriate for this MACT standard. With respect to legal concerns, some commenters indicated that CAA section 112(d)(4) establishes a mechanism for the EPA to exclude facilities from certain pollution control regulations and circumstances when these facilities can demonstrate that emissions do not pose a health risk. Commenters cited a Senate Report that influenced development of CAA section 112(d)(4), where Congress recognized that, "For some pollutants a MACT emissions limitation may be far more stringent than is necessary to protect public health and the environment." (Footnote: S. Rep. No. 101–128 (1990) at 171.) Commenters also cited regulatory precedent for addressing HCl as a threshold pollutant, including the Hazardous Waste Combustors and the Chemical Recovery Combustion Sources at Kraft, Soda, Sulfite, and Stand-Alone Semichemical Pulp Mills NESHAP. Commenters requested that the EPA incorporate the flexibility afforded by CAA section 112(d)(4) and allow sources reasonable means for demonstrating that their respective emissions do not warrant further control. The commenters also cited the 2004 vacated Boiler MACT as precedent for HBEL for HCl. The commenters contended that the EPA failed to explain why the health-based emissions limitations it established in the 2004 Boiler MACT and the justification provided for those limitations could not be used in this case. The commenters also cited a 2006

court briefing where the EPA vigorously defended the HBEL included in the 2004 Boiler rule when it was challenged in the D.C. Circuit (Final Brief For Respondent U.S. Environmental Protection Agency, D.C. Cir. Case No. 04–1385 (Dec. 4, 2006) at 59–65, 69).

Other commenters stated that on August 6, 2010, the EPA adopted a NESHAP for Portland Cement plants that specifically rejected adoption of risk-based exemptions or HBEL for HCl and manganese (Mn). These commenters argue there are no differences sufficient to warrant a reversal of that decision in the EGU MACT standard. The commenters raised concerns that health risk information cited by the EPA for HCl, HF, and hydrogen cyanide (HCN) does not establish "an ample margin of safety" and, therefore, no health threshold should be established. The commenters believe risk-based exemptions at levels less stringent than the MACT floor are prone to lawsuits that could potentially further delay implementation of the EGU MACT.

Some commenters disagreed with using a hazard quotient (HQ) approach to establish a risk-based standard because the HQ would not account for potential toxicological interactions. The commenter noted that an HQ approach incorrectly assumes the different acid gases affect health through the same health endpoint, rather than assuming that the gases interact in an additive fashion. This commenter suggested that a hazard index approach, as described in the EPA's "Guideline for the Health Risk Assessment of Chemical Mixtures," would be more appropriate.

Some commenters dispute that emissions from other EGUs or source categories should be considered when developing an HBEL and they argued that Congress expected the EPA to consider the effect of co-located facilities during the CAA section 112(f) residual risk program instead of under CAA section 112(d). Commenters added that there is no prior EPA precedent for considering co-located facilities from a different source category during the same CAA section 112 rulemaking.

Several commenters disputed the EPA's consideration of non-HAP collateral emissions reductions in setting MACT standards. They contended that the EPA's sole support for its "collateral benefits" theory is legislative history—the Senate Report that accompanied Senate Bill 1630 in 1989 and noted that the D.C. Circuit rejected this use of this theory since the Senate Report referred to an earlier version of the statute that was ultimately not enacted. Instead commenters suggested that other components of the CAA, such as the National Ambient Air Quality Standards (NAAQS), are more appropriate avenues for mitigating emissions of criteria pollutants.

Several other commenters suggested it is impossible to assess an established health threshold for HCl such that a CAA section 112(d)(4) standard could be set without evaluating the collateral benefits of a MACT standard. And, as described in the recently finalized cement kiln MACT rule, setting technology-based standards for HCl will result in significant reductions in the emissions of other pollutants, including SO_2, Hg, and PM. The commenter added that these reductions will provide enormous health and environmental benefits, which would not be experienced if CAA section 112(d)(4) standards had been finalized. These commenters contended that HCl and other dangerous acid gases produced by EGUs pose substantial risks to industrial workers, as well as surrounding communities, and must be limited by the strict conventional MACT standards.

Several commenters indicated that the current economic climate requires the EPA to balance economic and environmental interests and indicated that HBEL would help target investments into solving true health threats where limits are no more or less stringent than needed to protect public health. Many commenters provided estimates of compliance cost savings if an HBEL is included in this final rule. Some commenters stressed the importance of an HBEL for small entities affected by the regulations. Several other commenters suggested that the EPA should estimate the costs and environmental effects of the HBEL option compared to a conventional MACT standard in order to make an informed decision on the adoption of HBEL.

Response: After considering the comments received, the EPA has decided not to adopt an emissions standard based on its authority under CAA section 112(d)(4) for all the reasons set forth in the proposed rule.

The EPA notes that the Agency's authority under CAA section 112(d)(4) is discretionary. That provision states that the EPA "may" consider establishing health thresholds when setting emissions standards under CAA section 112(d). By the use of the term "may," Congress clearly intended to allow the EPA to decide not to consider a health threshold even for pollutants which have an established threshold. As explained in the preamble to the proposed rule, it is appropriate for the EPA to consider relevant factors when deciding whether to exercise its discretion under CAA section 112(d)(4), and, notwithstanding commenters' assertions to the contrary, the considerations we include in our analysis are reasonable. The EPA has considered the public comments received and is not adopting an emissions standard under CAA section 112(d)(4) for the reasons set forth in the proposed rule and explained below. We note that this action is consistent with EPA's recent decisions not to develop standards under CAA section 112(d)(4) for the Industrial, Commercial and Institutional Boilers and Process Heaters and the Portland Cement source categories.

As explained in the preamble to the proposed rule, the EPA continues to believe that the potential cumulative public health and environmental effects of all acid gas HAP emissions, not just HCl emissions, from EGUs and other acid gas sources located near EGUs supports the Agency's decision not to exercise its discretion under CAA section 112(d)(4). Additional data for all acid gas emissions were not provided during the comment period, and the data already in hand regarding these emissions are not sufficient to support the development of emissions standards for EGUs under CAA section 112(d) that take into account the health threshold for acid gas HAP, particularly given that the Act requires the EPA's consideration of health thresholds under CAA section 112(d)(4) to protect public health with an ample margin of safety. We note here that EPA agrees with the commenter who pointed out that a better way to evaluate the potential health impact interactions of all acid gases would be to use the approach in EPA's "Guideline for the Health Risk Assessment of Chemical Mixtures" rather than a simple evaluation of individual HQ values for each acid gas, but we further note that use of such an approach requires a substantially greater knowledge of acid gas emissions than is currently available. We further note that, even if cost were a relevant factor in setting standards under CAA section 112(d)(4), since the data are not available that would allow us to develop an acid gas HBEL appropriate to protect public health with an ample margin of safety, we cannot determine whether such standards would have any cost savings associated with them or not. In addition, the concerns expressed by the EPA in the proposal regarding the potential environmental impacts and the cumulative impacts of acid gases on public health were not assuaged by the

comments received because no significant data regarding these impacts were received.

The EPA also received comments recommending not only that the EPA establish emissions standards for acid gases pursuant to CAA section 112(d)(4), but that it do so by excluding specific facilities from complying with emissions limits if the facility demonstrates that its emissions do not pose a health risk. The EPA does not believe that a plain reading of the statute supports the establishment of such an approach. Although CAA section 112(d)(4) authorizes the EPA to consider the level of the health threshold for pollutants which have an established threshold, that threshold may be considered "when establishing emissions standards under [CAA section 112(d)]." Therefore, the EPA must still establish emissions standards under CAA section 112(d) even if it chooses to exercise its discretion to consider an established health threshold. A source-by-source standard is not mandated as some commenters seem to imply, and we are unsure how we could reasonably implement such an approach even if we determined such an approach was legally available. For these reasons alone, we concluded it was not appropriate to exercise our discretion to establish section 112(d)(4) standards for acid gas HAP emissions.

In addition, as explained in the preamble to the proposed rule, the EPA also considered the co-benefits of setting a conventional MACT standard for HCl. The EPA considered the comments received on this issue and continues to believe that the estimated co-benefits are significant and provide an additional basis for the Administrator to conclude that it is not appropriate to exercise her discretion under CAA section 112(d)(4). The EPA disagrees with the commenters who stated that it is not appropriate to consider non-HAP benefits in deciding whether to invoke CAA section 112(d)(4). Although MACT standards may directly regulate only HAP and not criteria pollutants, Congress did recognize, in the legislative history to CAA section 112(d)(4), that MACT standards would have the collateral benefit of controlling criteria pollutants as well and viewed this as an important benefit of the air toxics program. *See* S. Rep. No. 101–228, 101st Cong. 1st sess. at 172. The EPA consequently does not accept the argument that it cannot consider reductions of criteria pollutants in determining whether to take or not take certain discretionary actions, such as whether to adopt an HBEL under CAA section 112(d)(4). There appears to be no valid reason that, in situations where the EPA has discretion in what type of standard to adopt, the EPA must ignore controls which further the health and environmental outcomes at which CAA section 112(d) is fundamentally aimed because such controls not only reduce HAP emissions but emissions of other air pollutants as well. Thus, the issue being addressed is not whether to regulate non-HAP under CAA section 112(d) or whether to consider other air quality benefits in setting CAA section 112(d)(2) standards—neither of which the EPA is doing—but rather whether EPA may exercise its discretion to regulate certain HAP based on the MACT approach and consider collateral health and environmental benefits when choosing whether to exercise that discretion. The EPA believes there is no legal principle that precludes it from doing so and commenters have not provided one.

F. Compliance Date and Reliability Issues

Comment: Multiple commenters asked that the compliance date be clearly stated as soon as possible, as well as that guidance be provided for utilities unable to comply with the stated timelines, to allow time for utilities to prepare for compliance. Commenters also asked that any decisions or policies on extensions be published in a rulemaking. In addition, commenters requested that the EPA establish, streamline, and simplify the process of applying for the 1-year extension under CAA section 112(i)(3).

Multiple commenters offered suggestions on methods for allowing more time for compliance, including EPA's authority under CAA section 112(n)(1)(A); state authority under CAA section 112(i)(3); Presidential authority under CAA section 112(i)(4); categorical extensions for publicly-owned or governmental facilities according to EO 13132, 13563, and UMRA of 1995; state-designed programs under the delegation provisions of CAA section 112; various Consent Decrees; Administrative Orders of Consent (AOCs); temporary waiver mechanisms; and adoption of MACT compliance schedules through minor permit modifications of a source's Title V federal operating permits. Absent such considerations for additional compliance time, many commenters suggested that the reliability of the nation's electric grid would be jeopardized as utility companies were forced to retire EGUs because they could not install the needed controls in the requisite time.

Compliance times requested by commenters ranged from 1 additional year (4 years total) to 6 additional years (9 years total). Multiple commenters requested that a utility be required to demonstrate good faith progress toward compliance to get any extension. Some commenters suggested that the EPA require utilities to submit a notice concerning which EGUs will be retrofitted or retired within 1 year of the effective date; that the compliance date align with the Power Year used by RTOs; and that the EPA clarify that retirement and any clean replacement power that complies with the NESHAP rule, including off-site combined heat and power and waste heat recovery, can be deemed "controls" under the CAA.

Commenters noted the specific situations related to small entities and their inability to compete with the larger, investor-owned utilities for financing and engineering and technical labor as well as the different process they need to follow for capital improvements. Multiple commenters asked that the EPA consider other simultaneous rulemakings (*e.g.,* Cooling Water Intake Structures; Coal Combustion Residuals; CSAPR, etc.) and extend the compliance period. Many commenters noted these other requirements and suggested that installation of the necessary controls could not be completed within the compliance period allowed under CAA section 112, even if a fourth year were to be granted by the permitting authority, citing examples of the times necessary for installation of various pieces of control equipment or replacement power.

Some commenters pointed to existing state programs (*e.g.,* Colorado, Oregon, Washington) and indicated that if states can demonstrate that overall emissions reductions would be equivalent or greater than those that would be achieved by the proposed rule, the EPA should delegate the CAA section 112 program to these states, even if the state emissions reductions would not necessarily occur on the same schedule (many state programs call for retirement of EGUs in years beyond the CAA section 112 compliance date). The commenters did not want the promulgation of the final rule to undermine the significant amount of work that may have been invested in creating state-specific programs to curb emissions within a reasonable timeframe. The commenters seek to make use of temporal flexibility, authorized under CAA section 112(i)(3), in obtaining delegation of the final rule to preserve the hard-negotiated comprehensive state-specific programs designed to yield greater emission reductions than the MATS alone.

Other commenters requested that no additional time be granted for compliance. These commenters reference a number of reports (*e.g.,* by the URS Corporation, by M.J. Bradley & Associates and the Analysis Group, and by the Bipartisan Policy Center) to indicate that not only is technology readily available, but that the technology can typically be installed in less than 2 years and that the electric industry is well-positioned to comply with the EPA's proposed air regulations without threatening electric system reliability. Commenters assert that, if electric system reliability were to be threatened in local areas as a result of the rule, the EPA has the statutory authority to grant, on a case-by-case basis, extensions of time to complete the installation of pollution control systems. One commenter stated that no additional controls would need to be installed in many cases and any coal unit should be able to comply with all of the standards. Another commenter noted that utilities that failed to plan ahead "should not be permitted to use their own inaction to justify more time." Commenters noted that several major utility companies have anticipated the EPA's rules and are already taking action to ensure a reliable supply of electricity in their service territory and beyond. Other commenters agree that there is significant excess generation capacity in the country and reliability will not be threatened by the rule. According to one commenter, companies are already preparing for a 2015 compliance date, factoring in the capital expenditures required to comply and delays would undermine decisions that have already been made. Commenters cite, for example, recent electricity forward capacity market auctions in the PJM market for the period of 2014 and 2015 that indicate that the capacity markets cleared with electricity reserve margins of 20 percent; this is in excess of the default reliability targets used by the North American Electric Reliability Corporation (NERC) for the year 2015. One commenter quoted NERC, stating that NERC does not see impacts from proposed climate legislation or anticipated EPA regulation as a reliability concern. Another commenter noted that the Building and Construction Division of the AFL–CIO has stated that there is no evidence to suggest that the availability of skilled manpower will constrain pollution control technology installation. In fact, according to the commenter, given the high levels of unemployment in the construction sector, these jobs are much needed.

A number of commenters expressed concern that the time frame for compliance with a regulation under CAA section 112(d) was too short for this industry and would result in compromising the reliability of electricity supply. Commenters asserted that reliability would be compromised in several ways: (1) EGUs might have to temporarily close if the owner or operator is unable to install controls on the unit within the 3-year time frame or 3 years plus one; (2) the timing of outages to install controls will cause short term closures that could threaten grid stability; (3) owner/operators may shut down EGUs rather than invest in retrofits to keep them running and that these closures may cause a loss of critical generation; and (4) the construction of replacement generation or implementation of other measures to address reliability concerns due to plant retirements could take longer than 3 years, and that units slated for closure may be necessary beyond the 3-year compliance period but will be unable to run because they have not installed the necessary controls.

Response: Clean Air Act section 112 specifies the dates by which affected sources must comply with this rule. New or reconstructed units must be in compliance immediately upon startup or the effective date of this rule, whichever is later. Existing sources may be provided up to 3 years after the effective date to comply with the final rule; if an existing source is unable to comply within 3 years, a permitting authority has the ability to grant such a source up to a 1-year extension, on a case-by-case basis, if such additional time is necessary for the installation of controls.

As is explained earlier in this preamble, the 3-year compliance window is based on the date that is 60 days after publication of this rule in the **Federal Register.** Because publication doesn't occur until several weeks after the rule is signed by the Administrator, the earliest required date for compliance would be sometime in March 2015. Because the last stage of control installations usually needs to occur when the unit is off-line and because scheduled outages are usually scheduled for the spring or fall months when peak electric demand is lower, this additional time is significant as it provides companies an additional outage period, the spring of 2015, to install controls.

The EPA has considered the concerns raised by commenters and has concluded that given the flexibilities further detailed in this section, the requirements of the final rule for existing sources can be met by most sources without adversely impacting electric reliability. In particular, EPA believes that the flexibility of permitting authorities to allow a fourth year for compliance should be available in a broad range of situations (as discussed below), and that this flexibility addresses many of the concerns that have been raised. Furthermore as indicated below, in the event that an isolated, localized concern were to emerge that could not be addressed solely through the 1-year extension under CAA section 112(i)(3), the CAA provides flexibilities to bring sources into compliance while maintaining reliability.

The EPA considered the impact that potential retirements in response to this rule will have on resource adequacy in order to gauge the rule's impact on reliability. In considering these impacts, the EPA considered both the analysis it has conducted as well as analyses conducted by a number of other groups. The EPA's analysis shows that the expected retirements of coal-fueled units as a result of this final rule (4.7 GW) are fewer than was estimated at proposal and much fewer than some have predicted.[321] The net capacity reductions projected by the EPA make up less than one-half of one percent of the total generating capacity in the U.S. and about one and one-half percent of U.S. coal capacity. Because concerns have been raised that the use of DSI may not be as prevalent as the Agency has predicted and because this could lead to more coal retirements, the Agency also performed a sensitivity analysis in which fewer DSI systems and more scrubber systems were installed. In that sensitivity, we see approximately 1 more GW of retirements. This small change would have only a very small potential impact on resource adequacy. When considering the impact that one specific action has on power plant retirements, it is important to understand that the economics that drive retirements are based on multiple factors including: expected demand for electricity, the cost of alternative generation, and the cost of continuing to generate using an existing unit. The EPA's analysis shows that the lower cost of alternative fuels, particularly natural gas, as well as reductions in demand, will have a greater impact on the

[321] The EPA's analysis also identifies a small amount of capacity loss (less than 0.7 GW) due to derating of certain units, as well as partially offsetting reductions in non-coal retirements in comparison with the base case. The net estimated reduction in capacity, in comparison with the base case, is estimated at less than 5 GW.

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number of projected retirements than will the impact of this final rule.

The EPA's assessment looked at the capacity reserve margins in each of 32 subregions in the continental U.S. Demand forecasts used were based on EIA projected demand growth. The analysis shows that with the addition of very little new capacity, average reserve margins are significantly higher than required. The NERC assumes a default reserve margin of 15 percent while the average capacity margin seen after implementation of the policy is nearly 25 percent. Although such an analysis does not address the potential for more localized reliability concerns associated with transmission constraints or the provision of location-specific ancillary services (such as voltage support and black start service), the number of retirements projected suggests that the magnitude of any local reliability concerns should be manageable with existing tools and processes.

Several outside analyses have reached conclusions consistent with EPA's analysis. The DOE, in December 2011, published a report that looked at resource adequacy in the bulk power system when faced with a stress test which was a regulatory scenario far more stringent than EPA's regulations.[322] For this stress test, in addition to CSAPR and MATS requirements, each uncontrolled electric generator is required to install both a wet FGD system and a fabric filter to reduce air toxics emissions. If such installations are not economically justified, this scenario assumes that the plant must retire by 2015. In reality, as discussed previously, power plant owners will have multiple other technology options to comply with the regulations—options that typically cost less than installations of FGDs and fabric filters. The analysis finds that target reserve margins can be met in all regions, even under these stringent assumptions. Moreover, in every region but one (TRE), no additional new capacity is needed. In TRE, the analysis finds that less than 1 GW of new natural gas capacity would be needed by 2015 beyond the additions already projected to occur in the Reference Case. This analysis also finds that the total amount of new capacity that would be added by 2015 is less than the amount that is already under development.

In June 2011, the Bipartisan Policy Center issued a report analyzing potential collective impacts of EPA's pending power sector rules and concluding that "scenarios in which electric system reliability is broadly affected are unlikely to occur."[323]

In August 2011, PJM Interconnection—the Regional Transmission Operator (RTO) responsible for planning and reliable operation of the bulk power system serving all or portions of 13 states in the Mid-Atlantic and Midwestern regions—issued a report analyzing the impacts of the CSAPR and the proposed MATS rule.[324] Although PJM's analysis assumes substantially more retirements than EPA projects, it nevertheless concludes that resource adequacy is not threatened in the PJM region. This is particularly significant, given that the PJM region is one of the largest and most heavily dependent on coal-fueled generation in the country. The PJM analysis notes, as EPA has acknowledged, that even where there is adequate generation capacity on a regional basis, localized reliability issues may emerge in connection with retirements that may need to be addressed.

The EPA has reviewed industry and NERC studies suggesting, contrary to the EPA's and these other groups' analyses, that EPA rules affecting the power sector (including this final rule, the CSAPR, EPA's proposed rule addressing power plant cooling water intake systems under section 316(b) of the Clean Water Act (CWA), and EPA's proposed rule addressing coal combustion residuals under the Resource Conservation and Recovery Act) will result in substantial power plant retirements. Some of these studies predict that such levels of retirements will have adverse effects on electric reliability in some regions of the country. Although the specifics of these analyses differ, in general they share a number of serious flaws in common that call their conclusions into question.

First, most of these studies make assumptions about the requirements of the EPA rules that are inconsistent with, and dramatically more expensive than, the EPA's actual proposals or final rules. For example, a large proportion of the retirements projected by several of these studies is attributable to their inaccurate assumption that EPA's cooling water intake rule under CWA section 316(b) would require all or virtually all existing power plants to install cooling towers. In one study, the reliability effects reported are based on inaccurate assumptions that all existing EGUs with a capacity utilization factor of less than 35 percent would close, and that all in-scope electric generators would be required to install cooling towers within 5 years, whereas the not-selected options with closed cycle cooling in EPA's proposal envisioned that permit authorities could exercise discretion to allow facilities 10 to 15 years' time to comply. In most cases, these analyses were performed before the CWA section 316(b) rule or the MATS rule were even proposed; even analyses subsequent to the CWA section 316(b) proposal continue to inaccurately portray EPA's proposed approach.

Second, in reporting the number of retirements, many analyses fail to differentiate between plant retirements attributable to the EPA rules and retirements of older, smaller, and less efficient plants that are already scheduled for retirement because owners have made business decisions, based in significant part on market conditions, not to continue operating them.

Third, most of these analyses fail to account for the broad range of responses available to address electric reliability concerns associated with power plant retirements, including upgrades to the transmission system, construction of new generation, and implementation of demand-side measures. These measures are discussed at greater length below.

As a preliminary matter, none of these situations, either alone or in combination, will necessarily lead to an electric reliability problem. There is excess generating capacity in the U.S. today and in most cases an EGU that closes, either temporarily until it comes into compliance or permanently, will not cause a reliability problem. As explained above, our modeling of the impact of this final rule at the regional level projects retirements of less than one percent of nationwide generating capacity and confirms that there will continue to be adequate capacity in all 32 subregions of the country as sources comply with the rule.[325] This analysis shows that significantly less capacity will close in response to the final rule than might have under the proposal. Moreover, the regional modeling of retirements demonstrates that plants that close in response to this rule are spread out across the country rather than clustered in one area.

Outside analyses have identified many of the same flaws in studies

[322] U.S. Department of Energy, December 2011, "Resource Adequacy Implications of Forthcoming EPA Air Quality Regulations."

[323] Bipartisan Policy Center, June 2011, "Environmental Regulation and Electric System Reliability."

[324] PJM Interconnection, August 26, 2011, " Coal Capacity at Risk for Retirement in PJM: Potential Impacts of the Finalized EPA Cross State Air Pollution Rule and Proposed National Emissions Standards for Hazardous Air Pollutants."

[325] *See* Technical Support Document on Resource Adequacy in this Docket.

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projecting large-scale retirements as a result of EPA's power sector rules. For example, on August 8, 2011, the Congressional Research Service (CRS) [326] issued a report concluded that studies that assert that EPA rules will cause reliability problems, often make assumptions about the requirements of the rules that are inconsistent with, and dramatically more expensive than, the EPA's actual proposals. The CRS further noted that EPA's rules will primarily affect units that are more than 40-years old, that have not yet installed state-of-the-art pollution controls, and that are inefficient. Many of these plants are being replaced by combined cycle natural gas plants, driven more my lower gas prices than by EPA's regulations. The June 2011 Bipartisan Policy Center report referenced above likewise highlighted many of these same shortcomings in the studies in question.[327]

Although we do not expect to see any regional reliability problems, we acknowledge that there could be localized reliability issues in some areas—due to transmission constraints or location-specific ancillary services provided by retiring generation—if utilities and other entities with responsibility for maintaining electric reliability do not take actions to mitigate such issues in a timely fashion. There are many potential actions that could be taken to address this problem and multiple safeguards to assure a reliable electricity supply.

First, utilities can help to assure reliability through proactive steps in coordination with relevant planning and regulatory authorities. As we said in the proposal, early planning is key. The industry has adequate resources to install the necessary controls and develop the new capacity that may be required within the compliance time provided for in the final rule.[328] Although there are a significant number of controls that need to be installed across the industry, with proper planning, we believe that the compliance schedule established by the CAA can be met. Many companies have begun to do the detailed analysis and engineering and are ahead of others in their compliance strategy. There are already tools in place (such as integrated resource planning, and in some cases, forward auctions for future generating capacity) that ensure that companies adequately plan for, and markets are responsive to, future requirements such as this final rule.

Second, companies that intend to retire EGUs should formally notify their RTO (or comparable planning authority in the case of non-RTO regions), state regulatory agencies, and regional reliability entities as soon as possible of their compliance plans, particularly with regard to any planned unit retirements. As we said before, in most places a closing plant will not be a cause for concern for reliability. The same is true of any outages required for retrofitting of units with controls. To the extent there is concern, however, early notification will provide an opportunity for transmission planners, market participants, and state authorities to develop solutions to avoid a reliability problem. In RTOs with forward capacity markets, owner/operators that do not bid generating capacity that they plan to shut down will provide an advance signal to market participants to take action to assure adequate future capacity. In all regions, early and public notification will allow market participants, planning coordinators and state authorities, as appropriate and in a timely fashion, to bring new generation on line, put demand side resources in place, and/or complete any transmission upgrades needed to circumvent a potential issue. Most RTOs only require 45 to 120 days notification of closure. In combined comments to EPA, 5 RTOs suggested that such notification should be made no later than 12 months after this regulation is final in order to allow a smooth transitioning to action to avoid a reliability problem. The EPA strongly encourages sources to provide notice to the RTOs as early as possible and believes that responsible owner/operators should and will do the early planning for compliance and provide early notification of their compliance plans, especially where such plans include retiring one or more units.

On the supply side, there are a range of options including the development of more centralized power resources (either base-load or peaking) and/or the development of cogeneration or distributed generation. Even with the current large reserve margins, there are companies ready to implement supply-side projects quickly. For instance, in the PJM region, there are over 11,600 MW of capacity that have completed feasibility and impact studies; the units representing this capacity could be on-line by the third quarter of 2014.[329] The EPA notes, as well, that in the 3 years from 2001 to 2003, industry brought over 160 GW of generation on line.[330]

Demand side options include energy efficiency as well as demand response programs. These types of resources can also be developed very quickly. In 2006, PJM had less than 2,000 MWs of capacity in demand side resources. Within 4 years this capacity nearly quadrupled to almost 8,000 MW of capacity.[331] In addition to helping address reliability concerns, reducing demand through mechanisms such as energy efficiency and demand side management practices has many other benefits. It can reduce the cost of compliance and has collateral air quality benefits by reducing emissions in periods where there are peak air quality concerns.

With regard to transmission, recent experience also shows that, in many cases, transmission upgrades to address reliability issues from plant closures can be implemented in less than 3 years. For instance, when Exelon notified PJM of its intention to retire four units,[332] it was determined that transmission upgrades necessary to allow retirement of two units could be made within 6 months of notification, transmission upgrades for the third unit would require slightly over 1 year and transmission upgrades to allow the fourth unit to retire could be made in approximately 18 months.[333]

The CAA allows CAA Title V permitting authorities the discretion to grant extensions to the compliance time of up to one year if needed for installation of controls. *See* CAA section 112(i)(3)(B)). If an existing source is unable, despite best efforts, to comply within 3 years, a permitting authority has the discretion to grant such a source up to a 1-year extension, on a case-by-case basis, if such additional time is necessary for the installation of controls. Id. Permitting authorities should be familiar with the operation of the 1-year

[326] James E. McCarthy and Claudia Copeland, Congressional Research Service, August 8, 2011, "EPA's Regulation of Coal-Fired Power: Is a 'Train Wreck' Coming?".

[327] Bipartisan Policy Center, June 2011, "Environmental Regulation and Electric System Reliability."

[328] As stated above, EPA has provided the maximum compliance time authorized under CAA section 112(i)(3)(A).

[329] Paul M Sotkiewicz, PJM Interconnection, Presentation at the Bipartisan Policy Commission Workshop Series on Environmental Regulation and Electric System Reliability, Workshop 3: Local, State, Regional and Federal Solutions, January 19, 2011, Washington, DC, *http://www.bipartisanpolicy.org/sites/default/files/Paul%20Sotkiewicz-%20Panel%202_0.pdf,* slide 6.

[330] Form EIA–860 Annual Electric Generator Report, *http://www.eia.gov/cneaf/electricity/page/eia860.html.*

[331] BPC slides cited above—slide 5.

[332] *http://www.exeloncorp.com/Newsroom/pages/pr_20091202_Generation.aspx?k=eddystone.*

[333] Cromby Units 1 and 2 and Eddystone Units 1 and 2—Deactivation Study, Updated September 7, 2010—*http://policyintegrity.org/documents/20100907-cromby-and-eddystone-retirement-study-posting-update.pdf.*

extension provision because EPA has established regulations to implement the provision and the provision applies to all NESHAP. *See* 40 CFR 63.6(i)(4)(A).

We believe that the permitting authorities have the discretion to use this extension authority to address a range of situations in which installation schedules may take more than 3 years including: staggering installations for reliability reasons or other site-specific challenges that may arise related to source-specific construction, permitting, or labor, procurement or resource challenges. Staggered installation allows companies to schedule outages at multiple units so that reliable power can be provided during these outage periods. It can also be helpful for particularly complex retrofits (*e.g.,* when controls for one unit need to be located in an open area needed to construct controls on another unit). The additional 1-year extension would provide an additional two shoulder periods (*i.e.,* seasons flanking annual high-demand periods) to schedule outages, thus enabling owners/operators to gain the full benefit of staggering outages in support of complex installations. The EPA believes that although most units will be able to fully comply within 3 years, the fourth year that permitting authorities are allowed to grant for installation of controls is an important flexibility that will address situations where an extra year is necessary. That fourth year should be broadly available to enable a facility owner to install controls within 4 years if the 3-year time frame is inadequate for completing the installation.

As we indicated at proposal, this source category is unique due to the large, complex and interconnected nature of electrical generation, transmission and distribution, and the critical role of the electric grid in the functioning of all aspects of the economy. The grid functions as an interconnected system that supplies electricity to end users on a continuous basis. Safe, reliable operation of the grid requires coordination among actions taken at individual units, including timing of outages for the installation of controls, derating, or deactivation. It was for this reason that we specifically addressed in the proposed rule reasonable interpretations of the phrase "installation of controls" in CAA section 112(i)(3)(B). We determined that it was important to provide Title V permit authorities with information that might be useful if they were asked to authorize a fourth year for specific EGUs.

The EPA took comment on whether the construction of on-site replacement power could be considered the "installation of controls" such that a fourth year would be available while the replacement unit is being completed for a unit that is retiring (*e.g.,* a case when a coal-fueled unit is being shut down and the capacity is being replaced on-site by another cleaner unit such as a combined cycle or simple cycle gas turbine). After reviewing the comments, EPA believes that it is reasonable for permit authorities to allow the fourth year extension to apply to the installation of replacement power at the site of the facility. The EPA believes that building replacement power constitutes the "installation of controls" at a facility to meet the regulatory requirements.

Commenters were generally supportive of the proposed approach described above, but a number of commenters suggested several additional situations that should be considered as the "installation of controls" such that it would be appropriate for permitting authorities to grant a 1-year extension beyond the 3-year compliance time-frame. In particular, commenters suggested that the 1-year extension should be available for a unit if a company's compliance choice was to retire that unit but doing so within the 3-year time-frame caused reliability problems for any of the following reasons: (1) Generation from the retiring unit is needed to maintain reliability while other units install emission controls; (2) new off-site generation was being built to replace the retiring unit, but the new generation was not scheduled to be operational within the 3-year time-frame and any gap between the time the existing unit retires and the new unit comes on line would cause reliability problems; and (3) transmission upgrades were needed in order to maintain electric reliability after the unit retired but could not be completed within 3 years.

While the ultimate discretion to provide a 1-year extension lies with the permitting authority, EPA believes that all three of these cases may provide reasonable justification for granting the 1-year extension if the permitting authority determines, for example, based on information from the RTO or other planning authority or other entities with relevant expertise, that continued operation of a particular unit slated for retirement for some or all of the additional year is necessary to avoid a serious risk to electric reliability.

In a case where pollution controls are being installed, or onsite replacement power is being constructed to allow for retirement of older, under-controlled generation, a determination that an extra year is necessary for compliance should be relatively straightforward. In order to install controls, companies will have to go through a number of steps fairly early in the process including obtaining necessary building and environmental permits and hiring contractors to perform the construction of the emission controls or replacement power. This should provide sufficient information for a permitting authority to determine that emission controls are being installed or that replacement power is being constructed. Because companies will need to develop this information early in the process and because a determination can easily be made as to whether the schedule will exceed 3 years, the EPA believes that Title V permitting authorities should be able to quickly make determinations as to when extensions are appropriate.

In the three cases related to retirement of a unit without construction of onsite replacement power, additional information is needed. The Title V permitting authority should request that the affected company or companies provide information, including, for example, from the RTO or other planning authority for the relevant region, the state electric regulatory agency, NERC or its regional entities, and/or FERC or the DOE, demonstrating that retirement of a particular unit within the 3-year compliance period would result in a serious risk to electric reliability.

The first two situations involving a retiring unit—where one or more related existing units are upgrading pollution controls or a new unit is being constructed off-site—are similar to the situation we discussed in the proposed rule wherein a retiring unit at a facility runs an additional year while a replacement unit on the same site is constructed. In each of these situations, the retiring unit would be allowed to run so a unit compliant with the rule (either a retrofitted existing unit or a new unit) can come on line. We believe that these situations may, in the appropriate circumstances, constitute ones in which a 1-year extension for the retiring unit is "necessary for the installation of controls." In these two situations, however, we believe that it would be appropriate for the Title V permitting authority to consider reliability concerns as a necessary factor before granting the additional year because continuing operation of the retiring unit is only "necessary" to the extent it is required for reliability. In each of these situations, the permitting authority should determine that the retiring unit is necessary to maintain

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reliability until the new unit comes on line or the other existing unit is retrofitted. Title V permitting authorities may determine that multiple retiring units are available to maintain reliability, but unless all the units are necessary to address the issue, it would likely be unreasonable to provide the additional year for all the identified units.

The third hypothetical situation identified above is one in which transmission upgrades are necessary to address a reliability issue resulting from the retirement of a unit in order to comply with this rule, where the upgrade cannot be completed by the 3-year compliance date. In terms of the functionality of the electric grid, this situation has some similarity to those discussed above. Here, it is the completion of the transmission upgrades, rather than bringing another compliant (retrofitted or new) unit on line, that would allow the retiring unit to come into compliance (by retiring) without threatening reliability. The general objective and result is similar: Reductions of the existing unit's HAP emissions (through retirement) while maintaining electric reliability. If such situations develop and the reliability problem has been properly demonstrated, permitting authorities should consider whether an extension under CAA section 112(i)(3)(B) may be provided.

The EPA continues to believe, based on the analysis discussed at the beginning of this section, that most, if not all, units will be able to comply with the requirements of this rule within 3 years. The EPA also believes that making it clear that permitting authorities have the authority to grant a 1-year compliance extension where necessary, in the range of situations described above, addresses many of the other concerns that commenters have raised. The EPA believes that the number of cases in which a unit is reliability critical and in which it is not possible to either install controls on the unit or mitigate the reliability issue through construction of new generation, transmission upgrades, or demand-side measures, within 4 years, is likely to be very small or nonexistent. This view is consistent with statements from commenters explicitly mandated with ensuring grid reliability.

The EPA's authority to provide relief from the requirements of this final rule beyond the fourth year is limited by the statute. If reliability issues do develop, however, the CAA provides mechanisms for sources to come into compliance while maintaining electric reliability. One area where the EPA has some measure of flexibility is with respect to the exercise of its enforcement authorities. The Agency has used such authority in the past to bring sources into compliance with the requirements of the CAA while maintaining electric reliability, although these authorities are not as flexible as suggested by some commenters.

The EPA generally does not speak publicly to the intended scope of its enforcement efforts, particularly well in advance of the date when a violation may occur. In light of the importance of ensuring electric reliability, however, the Office of Enforcement and Compliance Assurance will separately publish a document that articulates our intended approach with respect to sources that operate in noncompliance with this final rule to address a specific and documented reliability concerns.

That document provides a pathway for reliability critical units (as such units are described in the document) to achieve compliance within an additional year. The result is that qualifying reliability critical units may come into compliance within up to 5 years. This pathway is structured to maintain reliability, to ensure CAA compliance and to increase certainty for sources in planning by allowing a unit owner/operator to determine whether it qualifies for a compliance schedule well in advance of the MATS compliance deadline.

The EPA believes that there will be few, if any, situations in which it will be necessary to have recourse to the processes discussed in the document just described, and that there are likely to be fewer, if any, cases in which it is not possible to mitigate a reliability issue within the further year contemplated under that document. However, there is always the possibility that some unit owner/operator will be unable to address its reliability issues within 5 years and there is always the possibility that a unit owner/operator will be unable to timely comply with the MATS for some other reason. Consistent with its longstanding historical practice under the CAA, the EPA will address individual non-compliance circumstances on a case-by-case basis, at the appropriate time, to determine the appropriate response and resolution.

A number of commenters also raised concerns about inconsistencies between the compliance timelines under this final rule and existing state agreements with specific owners/operators to install pollution control equipment and/or retire EGUs. The EPA believes the flexibilities provided in this discussion allow for some discretion to address those cases, but that they may not be fully addressed. The EPA is supportive of such efforts and believes they can have important multi-pollutant health and environmental benefits. To the extent that the flexibilities discussed here do not fully address a particular situation, we encourage states and sources to contact the EPA as early as possible to discuss their individual circumstances.

G. Cost and Technology Basis Issues

1. Dry Sorbent Injection

Comment: Several commenters stated that there is limited commercial operating experience in using DSI to control acid gas emissions from coal-fired boilers. They suggest that the technology is not adequately proven for use in this application.

Other commenters disagree with statements made that DSI is not proven. One commenter stated that DSI is a mature technology. The commenter indicated that DSI is well suited for units that burn fuels with lower or mid-level sulfur contents, and is among the viable options available for a number of sources to achieve the proposed HCl limits. Thus, the commenter believes that DSI represents a real technology control option for many units, and is among the suite of technology options that certain units will be able to employ to meet the proposed HCl limit.

Response: As explained in this response and elsewhere in this preamble, the EPA agrees that DSI technology is proven and ready for commercial use in controlling acid gases from coal combustion. One of the largest coal-burning electric utilities in the U.S, American Electric Power (AEP), pioneered the practical use of DSI with trona, a sodium-based sorbent, for SO_3 mitigation. American Electric Power has implemented trona injection for that purpose across its entire bituminous coal-fired fleet where both SCR and wet FGD systems are in place.[334] Examples of coal-fired EGUs already using trona DSI to control SO_2 emissions include NRG Energy's Dunkirk Generating Station Units 1–4 and CR Huntley Units 67 and 68 in New York.[335] The Dunkirk units range in size from 75 MW to 190 MW. Much larger units may also be economic when using DSI for SO_2 control, as suggested by Dominion Energy's studies of adding DSI on two

[334] *SO_3 Control: AEP Pioneers and Refines Trona Injection Process for SO_3 Mitigation,* Coal Power, March 2007, *http://www.coalpowermag.com/plant_design/SO3-Control-AEP-Pioneers-and-Refines-Trona-Injection-Process-for-SO3-Mitigation_29.html.*

[335] NRG Energy letter to RGGI, Inc, November 22, 2010, *http://www.rggi.org/docs/NRG_Nov_2010.pdf.*

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625 MW units at the Kincaid plant in Illinois.[336] One of the largest suppliers of air emission control systems in the world, vouches that DSI is commercially proven for acid gas control:[337] [338]

Comment: Numerous comments were received on EPA's IPM modeling of DSI in the MATS analysis. A few commenters stated that DSI will not work on bituminous coals. Some commenters stated that DSI is only suitable for use on low sulfur, low chlorine western coals. Others stated that DSI is only likely to be used on relatively small units, and that larger units would use scrubbers for acid gas control. Several commenters expressed the opinion that because there is little commercial operating experience in using DSI to control SO_2 emissions from coal-fired boilers, EPA's IPM modeling assumptions on the efficacy and cost of the DSI control option are unjustifiably optimistic. Some commenters believe that DSI will not be as economic or as widely applicable for either SO_2 or HCl control as projected by EPA's IPM modeling. Commenters observe that wet or dry scrubbers for FGD, longer-standing control technologies for SO_2 and HCl, are more complex systems with a much higher capital cost than DSI. These commenters argue that the sector will need to retrofit many more FGD scrubbers than projected by IPM for MATS compliance and will therefore experience a much higher overall cost of compliance than projected by IPM, as well as needing more time and resources for retrofit construction. A few commenters suggested that EPA should base its MATS modeling on this more conservative outlook. A few commenters were concerned that EPA's DSI modeling assumptions relied on performance data from only one DSI vendor.

Some commenters were concerned that fly ash currently sold for beneficial uses will become unsalable because it will be contaminated by injected sodium-based DSI sorbents. Two commenters argued that EPA's IPM analysis understates DSI cost by not including the costs of foregone fly ash sales revenue and contaminated fly ash disposal. A few commenters observed that landfilling of sodium-based DSI solid wastes will produce leachate containing sodium and other compounds that are challenging to handle, thus requiring special landfill designs and a high cost for landfill disposal of DSI waste.

Response: The EPA believes that its representation of DSI in MATS compliance modeling is reasonable, is properly limited to applications that are technically feasible, and reflects a conservative approach to modeling future use of this technology.

The EPA disagrees that its IPM modeling of DSI is overly optimistic and therefore underestimates the costs of MATS compliance. In its IPM modeling, EPA restricts the availability of the DSI option to only those units that use or switch to relatively low sulfur coal: Less than 2 lb SO_2/MMBtu (*see* IPM documentation in the docket). The EPA's IPM projections for MATS compliance, therefore, already include the costs of any additional FGD scrubbers that are economically justified and projected for use on units using higher sulfur coals. The EPA models DSI assuming fine-milled trona as the injected sorbent. As mentioned by several commenters, sodium bicarbonate (SBC), which is processed from trona, is also suitable for use with DSI. Sodium bicarbonate is more reactive with acid gases than trona. It would require less tonnage of sorbent and less tonnage of waste disposal than trona for the same SO_2 removal effect, albeit at somewhat higher sorbent cost. Non-sodium based sorbents such as hydrated lime (calcium based) could also be used. Therefore, EPA's modeling of DSI technology does not include the full spectrum of sorbent choices that real-world applications enjoy, meaning that there may be opportunities for lower-cost applications of DSI that are not captured in EPA's projections for MATS. The EPA models DSI with trona injection rates corresponding to 70 percent SO_2 removal for all coals, assuming that an equivalent amount of sorbent is needed to provide 90 percent HCl removal, regardless of the low sulfur and chlorine content of western coals.

Senior technical staff from the EPA have carefully evaluated the key assumptions regarding the cost and operation of emission control technologies. In general, these staff believe that trona should have strong HCl reaction selectivity and, consequently, EPA's assumed trona injection rates may be overstated. The extent to which this assumption may actually overstate DSI control costs can be observed through DSI pilot testing for Solvay Chemicals by the Energy & Environmental Research Center (EERC) at the University of North Dakota.[339] The EERC's testing of trona DSI on a central Appalachian bituminous coal (1.3 lb SO_2/MMBtu) substantiates the strong HCl reaction selectivity of sodium-based sorbents, including trona, and calcium-based hydrated lime. The EERC's pilot testing shows that fine-milled trona, when well mixed into 325 °F flue gas upstream of a FF, provides 90 percent HCl removal at a SO_2 removal rate of less than 20 percent (as compared to EPA's modeling assumption of aligning 90 percent HCl removal with sorbent injection designed to achieve 70 percent SO_2 removal). The data show that 95 percent or higher HCl removal is readily obtained at somewhat higher SO_2 removal rates. Similarly strong HCl selectivity results were obtained using trona and an ESP at 650 °F. Test data from United Conveyor [340] on full-scale units also show these high HCl selectivity trends. Overall, these test data from multiple major vendors suggest that even if a SO_2 removal rate of 30 percent were required in order to obtain 90 percent HCl removal in the imperfectly mixed flow of a full-scale unit, it still appears that EPA's assumed trona injection rates may be as much as twice as high as would actually be needed in practice for certain applications. It is apparent that if EPA were to re-analyze MATS compliance with DSI injection rates reduced by 50 percent, there would be a corresponding reduction in the sorbent and related waste disposal costs that constitute most of the cost of using DSI.

Given the EERC test data, it is also apparent that most units that have ESPs and are burning low sulfur western coal could meet the HCl limit using DSI without the addition of a FF. If EPA were to re-analyze MATS compliance while allowing DSI use without the need for a downstream FF, it is apparent that there would be a very significant reduction in the overall number of FF retrofits projected, and a corresponding reduction in annualized capital costs. For the MATS proposal, the EPA modeled DSI on the assumption that all chlorine in coal converts to HCl, and that DSI would be the only mechanism by which the unit could prevent HCl from being emitted. Based on public

[336] Dominion Energy, *BART Analysis for the Kincaid Power Plant,* January 2009, *http://www.epa.state.il.us/air/drafts/regional-haze/bort-kincaid.pdf.*

[337] Dry Sorbent Injection Systems for Acid Gas Control, Babcock & Wilcox, 2010, *http://www.babcock.com/library/pdf/ps-451.pdf.*

[338] Technologies for Acid Gas Control, Babcck & Wilcox, 2011, *http://www.babcock.com/library/pdf/ps-457.pdf.*

[339] Solvay Chemicals, Inc., HCl Removal in the Presence of SO_2 Using Dry Sodium Sorbent Injection, *http://www.solvair.us/SiteCollection Documents/presentations/20111214_hcl_presentation.pdf.*

[340] United Conveyor Corporation, *Dry Sorbent Injection for Simultaneous SO_2, HCl, and Hg Removal,* October 2011, *http://unitedconveyor.com/uploadedFiles/Systems/Systems_Sub/McIlvaine%20Multipollutant%20Removal%20Oct%202011.pdf.*

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comments and a more thorough review of the ICR data, the EPA has introduced in final MATS modeling a recognition that the relatively high alkalinity of ash from subbituminous and lignite coals "removes" much of the HCl that would otherwise be emitted from combustion of these particular coals. The 2010 ICR data indicate that in some cases the ash itself removes sufficient HCl from these coals for MATS compliance; in effect, these acid-gas emissions are absorbed by coal ash and are captured by particulate control devices instead of being emitted in gaseous form. As a conservative measure, EPA's revised final MATS modeling assumes that 75 percent of HCl is removed by the ash for these coals. In the event that ash capture in practice is more effective than this 75 percent assumption, then EPA's analysis projects a conservatively higher level of DSI installations (and, thus, compliance cost) than would actually occur in practice. In any case, it appears that significantly less sorbent injection would actually be required in practice than assumed by EPA for these low sulfur, low chlorine coals, and that the IPM projected DSI operating costs are likewise higher for these coals than would be experienced in practice.

The EPA models DSI with sorbent injection occurring downstream of an existing electrostatic precipitator (ESP). The existing ESP is assumed to remain in service. The model adds a fabric filter downstream of the DSI injection point to capture the small amount of PM passing through the ESP plus the reacted and unreacted DSI sorbent. Most of the DSI projected by IPM, therefore, includes the costs of a retrofitted FF. This modeled configuration allows fly ash currently captured in ESPs to remain uncontaminated by DSI sorbent and, therefore, remain available for sale and beneficial use. The EPA conservatively models FF costs based on an assumed full-size system with an air-to-cloth ratio of 4.0. The FF costs could be somewhat less in practice if a smaller system (with an air-to-cloth ratio of 6.0) were used for the reduced DSI dust loading. The EPA observes that some of the owners of units with ESPs may chose to convert existing ESPs into FFs,[341] an option not modeled in IPM, but that would likely have a lower capital cost than a retrofitted FF. In the MATS proposal EPA modeled DSI with a waste disposal cost of $50/ton, based on a Sargent & Lundy DSI cost model prepared for EPA (*see* proposal IPM documentation in the docket). The EPA has continued to model DSI at this waste disposal cost for analysis of the final rule. However, recent discussions between senior technical staff from the DOE and the EPA have suggested that in some situations sodium sulfates, that would be formed by the injection of trona, could potentially leach out of the fly ash/sorbent mixture on contact with water. Although the technical staff recognized that these concerns are more relevant to bituminous coal-fired units where ashes are not cementitious, unless mixed with limestone or lime, they suggested that the impacts of potentially higher disposal costs be evaluated. Based on public comments, further investigations by Sargent & Lundy, and suggestions from the EPA and DOE technical staff, EPA's analysis of the final rule has included an IPM sensitivity case using a DSI waste disposal cost of $100/ton. The sensitivity case indicates that a 100 percent increase in assumed DSI waste disposal cost produces slightly less than a 1 percent increase in the projected cost of the rule.

Comment: A few commenters expressed the concern that there is an inadequate supply of trona to support DSI operations at the levels projected by the EPA for MATS compliance.

Response: The EPA projects that just over 50 GW of coal-fired capacity might retrofit with DSI for MATS compliance, thus reducing SO_2 emissions by about 1 million tons per year. Based on conservatively high trona injection rates, as discussed above, the EPA estimates that the amount of trona required to support DSI operations at this level is about 4 million tons per year. By comparison, the trona mining industry in the U.S. has a demonstrated production capacity of at least 18 million tons annually, and was running well below that capacity (16.5 million tons) in 2010.[342] [343] If the EPA's assumed trona injection rates are as much as 50 percent greater than actually needed for at least 90 percent HCl control, as discussed above, and given that some subbituminous coals will apparently need little or no sorbent injection for HCl control, there may already be an adequate surplus of trona production capacity to support DSI for MATS compliance. The EPA, therefore, concludes that trona supply for DSI is either already adequate, or will require at most a small increase in production capacity.

For all of these reasons, the EPA believes that its representation of DSI in MATS compliance modeling is reasonable, is properly limited to applications that are technically feasible, and reflects a conservative approach to modeling future use of this technology.

2. Economic Hardship

a. Job Losses and Economic Impacts

Comment: Several commenters indicated that they believe the proposed rule will weaken industry, cause job losses and hurt power consumers. One commenter reported that the proposed rule will affect 1,350 coal and oil-fired units at 525 power plants and that NERC reports that by 2018 nearly 50,000 MW of capacity will be retired by the proposed rule. Many of these commenters compared the cost estimated by EPA to a variety of other sources that estimate substantially higher costs of the rule. The commenters expressed concern that electricity price increases are likely to be up to 24 percent in some regions as a result of the proposed rule. In addition to the economic difficulty the proposed rule could place on consumers, the commenter believes that many in the energy sector will lose their jobs due to coal-fired capacity losses. The commenters believe the effects on coal-fired plants in the Southeast especially will mean the loss of high-paying, high-skilled jobs and drastic price increases in energy costs. Additionally, commenters expressed concern that increased electricity and natural gas prices would impact businesses in multiple sectors across the country.

Response: The EPA disagrees with the estimates presented by the commenters. The EPA has updated its analysis to reflect the final MATS. The Agency estimates the annual costs of the final rule in 2015 to be $9.6 billion in 2007 dollars. The estimate of early retirements of coal-fired units due to this rule is 4.7 GW, lower than the level estimated at proposal. Both of these estimates were prepared using the IPM, a model that has been extensively reviewed and has been utilized in several rulemakings affecting the power generation sector over the last 15 years. The Agency's analyses are credible and accurate to the extent possible, and all assumptions and data are made public. Limitations and caveats to these analyses can be found in the RIA for this rule.

The EPA estimates that there will be an increase of 3.1 percent in retail

[341] TW Lugar, *et al., The Ultimate ESP Rebuild: Casing Conversion To a Pulse Jet Fabric Filter, a Case Study,* Electric Power Conference, May 2009, *http://www.cecoenviro.com/uploads/ESP%20to%20Fabric%20Filter%20Baghouse%20Conversion%20-%20Buell%20Case%20History.pdf.*

[342] *http://www.wma-minelife.com/trona/tronmine/tronmine.htm.*

[343] *http://www.wma-minelife.com/trona/TronaPage2/trona_production.htm.*

electricity price on average in the contiguous U.S. in 2015 as an outcome of this rule, with the range of increases from 1.3 percent to 6.3 percent in regions throughout the U.S. No region of the U.S. is expected to experience a double-digit increase in retail electricity prices in 2015 or in any year later than that, according to the Agency's analysis, as a result of this rule. To put this in context, the roughly 3 percent incremental increase in aggregate end-user electricity prices projected to occur over the next 4 years is about the same as the 3 percent absolute average change in total end-user electricity prices observed on an annual basis.[344] Furthermore, the roughly 3 percent incremental price effect of this rule is small relative to the changes observed in the absolute levels of electricity prices over the last 50 years, which have ranged from as much as 23 percent lower (in 1969) to as much as 23 percent higher (in 1982) than prices observed in 2010.[345] Even with this rule in effect, electricity prices are projected to be lower in 2015 and 2020 than they were in 2010.[346]

The Agency found that the readily discernible impact on long-term employment nationally within the most directly affected sectors should be small and the EPA also estimated that about 46,000 job-years[347] of one-time construction labor could be supported or created by this rule. This includes jobs manufacturing steel, cement and other materials needed to build pollution control equipment, jobs creating and assembling pollution control equipment, and jobs installing the equipment at power plants. Potential job increases from increased output by lower-emitting facilities (such as increased generation from well-controlled coal-fired plants that replace generation from older coal-fired plants) are expected to partially or fully offset potential job losses resulting from reduced output from higher-emitting facilities. The EPA analysis projects a net change in the directly affected EGU sector of between 15,000 net jobs lost to 30,000 net jobs gained on an annual basis.[348] See Chapter 6 of the RIA for further details.

The EPA has also looked at the possibility that changes in the price of electricity may influence the levels and geographic distribution of downstream economic activities, and associated employment. Projecting how potentially higher electricity prices may affect various downstream economic activities in particular regions as a result of this rule is challenging for several reasons: (1) There are significant uncertainties regarding projections of consumer- and location-specific electricity price changes in response to future firm-specific compliance strategies; (2) the availability of competitively-priced alternative energy sources (including energy conservation) and less electricity-intensive substitute goods and services may significantly mitigate potentially adverse economic consequences resulting from projected increases in electricity prices in ways which are not captured effectively in currently available models; and (3) available modeling tools are not configured to capture the effects over time of economically significant effects of cleaner air (*e.g.,* reductions in medical expenditures and improvements in labor productivity resulting from fewer lost work days) achieved by rules evaluated using single target year criteria pollutant and/or HAP benefits projections. After considering these methodological limitations, the Agency concludes that there is not a satisfactory methodology for projecting the downstream economic (including employment) effects of any changes in electricity prices due to this rule.

We expect the downstream economic effects of this rule to be small because electricity is only a small factor in the production of most goods and services.[349] A 3 percent increase in end-user electricity prices translates to a much smaller effect on prices and potential output of goods and services from end-users of electricity. Over time, the incremental effect of this rule on electricity prices is projected to diminish significantly; for example the difference in expected prices is projected to narrow from 3.1 percent in 2015 to 2.0 percent in 2020 as shown in Chapter 3 of the RIA.

Despite the absence of a satisfactory methodology for quantifying the potential economy-wide effects (including employment) of any potential increases in electricity prices resulting from this rule, the EPA expects the incremental effects of this rule on electricity prices to be small given the projected electricity price increases relative to historical levels and volatility in end-user electricity prices. Based on these projections and contextual information, the Agency believes that the incremental effects on electricity prices and economic activity of this rule are likely to be small relative to other factors influencing electricity prices, overall employment, and other aspects of economic activity.

Comment: Several commenters considered the proposed rule to be a tax on the American public, since utilities implementing upgrades will pass the costs on to the consumer. Commenters questioned the preference of Americans to subsidize renewable energy sources and put money into the proposed rule instead of other environmental programs with greater benefits. Commenters explained that the tax-like price increase reduces income of energy consumers and depresses business development. The commenters used California as an example of a state that uses low rates of coal-based electricity and cites companies that have left the state as a result of substituting higher cost forms of electricity for coal. A commenter stated that coal-derived energy will rapidly become more expensive, especially in the "rust belt" and Southeast region, as can be seen by the rate increase already requested in Louisville. A commenter believes the "indirect taxation" limits the ability of the economy to absorb the cost of retrofitting and new capacity projects, lowers discretionary spending and leads to job losses and lost tax revenues, given the restrictive timeframe for compliance.

Response: The Agency does not agree that this rule creates or alters any taxes on affected sources required under this rule to reduce their emissions of toxic air pollutants, nor are taxes created or altered or imposed on consumers of electricity which is provided to the market by affected sources. Moreover, unlike a tax, this rule does not generate government revenue. The rule does, however, indirectly address the problem of the "externality cost" of higher health risks and other adverse effects on the populations exposed to toxic air pollution emissions from affected sources. This rule may have the effect of

[344] EIA Annual Energy Outlook 2010 annual total electricity prices from 1960 to 2010, Table 8–10.

[345] Ibid, EIA AEO 2010, Table 8–10.

[346] Ibid, EIA AEO 2010, Table 8–10 for price levels; and Chapter 3 of the RIA for electricity price differential.

[347] A "job-year" is a combined measure of jobs and job duration which is equivalent to one person being employed for one year. For example, 2 job-years could represent two years of employment for one worker, one year of employment for two workers, or 6 months of employment for four workers. Estimates of employment changes that involve non-permanent workers are usually reported in job years to give a sense of the total employment effects.

[348] It should be noted that if more labor must be used to produce a given amount of output, then this implies a decrease in labor productivity. A decrease in labor productivity will cause a short-run aggregate supply curve to shift to the left, and businesses will produce less, all other things being equal.

[349] BEA. (2007b). Commodity-by-Industry Direct Requirements after Redefinitions, 2002. Available in: *2002 Summary Tables, 2002 Benchmark Input-Output Data.* Retrieved from *http://www.bea.gov/industry/io_benchmark.htm#2002data.*

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reducing or eliminating a market distortion that provides an implicit subsidy to affected facilities. This implicit subsidy results from the fact that some facilities currently can avoid the costs of toxic air pollution controls by imposing higher health and other costs on those who are exposed to higher levels of toxic air pollution. The Agency also disagrees with the implication that the costs incurred by less-controlled sources to bring their toxic air emissions in line with their better-controlled competitors will lead to significant or debilitating changes in market and economic conditions. The Agency's estimate of the potential increase in retail electricity price is an average of 3.1 percent in 2015, with a range of increases by region from 1.3 percent to 6.3 percent. As shown in Chapter 3 of the RIA, the higher rates of potential electricity price increase tend to occur in those regions where electricity prices have been relatively low, due to some extent to reliance on coal-fired units which have been cheaper to operate due to underinvestment in toxic air pollution controls.[350] As shown in Chapter 3 of the RIA, all regions with year 2015 projected percentage increases in retail electricity prices above the contiguous U.S. average are also projected to have baseline retail electricity prices which are below the contiguous U.S. average price level in that year. In addition, natural gas prices will only increase by 0.3 to 0.6 percent on average over the time horizon of 2015 to 2030. As discussed above, for consumers of electricity in the commercial and industrial sectors, electricity tends to be a fairly small fraction of total costs of production, implying that the average projected electricity price increase of 3 percent will lead to only a small fractional change in the costs of providing goods and services to the economy. While some residential electricity consumers may similarly see a small price increase in retail electricity prices, it should be noted that these consumers tend to reside in the same area or region as the affected facility and so will also experience the improvement in air quality from the reductions due to the rule. The reduction in health risk and other improvements to quality of life associated with lower exposure to toxic and other air pollutants achieved by this rule will confer benefits on these consumers which include lower risks of premature mortality, lower morbidity, and improved productivity and competitiveness of U.S. workers due to reduction in work days lost to air pollution-related illness. The benefits of these improvements are projected to exceed costs of compliance by affected sources by at least six-fold. The potential price increases in electricity and natural gas should be considered in light of the substantial health, welfare, and economic benefits achieved by this rule.

Comment: Many commenters expressed support for the EPA's impact analysis and disputed claims by other commenters that the projected rule will harm economic growth. A number of commenters mentioned testimonials by power company CEOs stating that the proposed rule will not affect the economic health of the industry and a survey showing nearly 60 percent of the coal-fired units already comply with the EPA's proposed Hg standard, and several other meaningful quotes from utility executives. The commenters also pointed out that 17 states already require plants to address Hg pollution, with some imposing more stringent emission limits than the EPA proposes. The commenters believe that utilities use the threat of power plant closures and lost jobs to delay Hg reductions from coal-fired plants. Commenters also believe that the rules will drive innovation and job creation as new technologies to reduce pollution are created. Several commenters quoted the Economic Policy Institute finding that the proposed rule will increase job growth by 28,000 to 158,000 jobs by 2015 (including approximately 56,000 direct jobs and 35,000 indirect jobs), the University of Massachusetts study that showed an increase 1.4 million jobs in 5 years, and the Constellation Energy Group installation project that employed nearly 1,400 skilled workers. Commenters also cited the University of Massachusetts study statement that a net gain of over 4,200 long-term operation and maintenance jobs will result.

Several commenters observed that the positive impacts of the rule strongly favor its adoption. These commenters stated that, contrary to the unfounded assertions by critics of EPA and the rule, EPA has conducted a technically sound and conservative benefit-cost analysis showing that the proposed rule's estimated benefits are at least five times as high as its costs. One commenter stated, "With sound, albeit unduly conservative, econometric modeling, EPA has also determined that the Toxics Rule will promote economic growth and create jobs in both the long and short term." Two commenters cited the EPA impact analyses by Dr. Charles Cicchetti which confirm this finding and state that the analysis underestimates the rule's net benefits and positive impacts on the nation's economy. By considering some benefits not monetized in the EPA analysis, Dr. Cicchetti concludes that the proposed rule will create $52.5 to $139.5 billion in net benefits annually, create 115,200 jobs, generate annual health savings of $4.513 billion, annual increases in GDP of $7.17 billion and $2.689 billion in additional annual tax revenues, and spur innovation and modernization of EGUs. The commenters state that the study findings show no need to delay implementation of the rule or needlessly duplicate economic analyses already completed.

Commenters reported that multiple researchers confirmed that the EPA's estimates of economic stimulus are conservative and that the proposed rule will stimulate job growth. A commenter quotes Dr. Josh Bivens of the Economic Policy Institute, who also found that EPA's conclusions were conservative. Dr. Bivens concluded, "The EPA RIA on the proposed toxics rule makes a compelling case that the rule passes any reasonable cost-benefit analysis with flying colors—the monetized benefits of longer lives, better health, and greater productivity dwarf the projected costs of compliance * * * Whether regulation in general and the toxics rule in particular costs jobs is an empirical question this paper attempts to answer. In particular, this paper examines the possible channels through which the proposed toxics rule could affect employment in the United States and finds that claims that this regulation destroys jobs are flat wrong: "The jobs-impact of the rule will be modest, but it will be positive." His report details the following major findings:

1. The proposed rule would have a modest positive net impact on overall employment, likely leading to the creation of 28,000 to 158,000 jobs between now and 2015.

2. The employment effect of the [MATS] on the utility industry itself could range from 17,000 jobs lost to 35,000 jobs gained.

3. The proposed rule would create between 81,000 and 101,000 jobs in the pollution abatement and control industry (which includes suppliers such as steelmakers).

4. Between 31,000 and 46,000 jobs would be lost due to higher energy prices leading to reductions in output.

5. Assuming a re-spending multiplier of 0.5, and since the net impact of the above impacts is positive, another 9,000 to 53,000 jobs would be created through re-spending.

[350] *http://www.epa.gov/airmarkets/images/CoalControls.pdf.*

Response: The EPA thanks the commenters for these observations. The Agency's estimates of employment impacts, found in the RIA for the rule, are smaller than those identified by the some commenters, though the EPA uses a different methodology that focuses on impacts specific to the electric power sector.

b. Impacts on Low-Income Consumers

Comment: Commenters expressed concern that the EPA's overview of the price increases does not consider the hardships that will be the reality of increased prices on low-income or fixed-income households or small businesses. The commenter reports increases of $90 million in capital costs, $11.4 million in annual operating costs and $6.4 million in annual debt service costs to achieve compliance, which will lead to a 13 percent increase in rates for the proposed rule, and a 41 percent increase for all proposed and new regulation compliance costs. The commenter argues against the EPA's view that energy efficiencies will offset rate increases, because low income customers will need to use less electricity due to economic necessity. The commenter also sees large price increases for customers if units are converted to natural gas, which is approximately 2.5 times more expensive than the coal that the commenter currently uses to generate electricity.

Response: The EPA's estimates of increase, relative to the baseline, in the retail electricity price range from 1.3 percent to 6.3 percent regionally in 2015, with an average increase nationwide of 3.1 percent in 2015. Low-income households will thus see some increase in electricity price, but this increase should be modest. In addition, the increase in the price of natural gas as a result of this rule is expected to be 0.3 to 0.6 percent over a time horizon of 2015 to 2030. This increase in price is low enough that electricity customers should not experience a major increase in price resulting from any modest changes to electricity generated by natural gas. The roughly 3 percent incremental price effect of this rule is small relative to the changes observed in the absolute levels of electricity prices over the last 50 years, which have ranged from as much as 23 percent lower (in 1969) to as much as 23 percent higher (in 1982) than prices observed in 2010.[351]

[351] EIA Annual Energy Outlook 2010 annual total electricity prices from 1960 to 2010, Table 8–10.

c. State or Regional Impacts

Comment: Multiple commenters expressed concern over the impact of the rule on electricity prices and reliability in specific states or regions. These commenters were concerned that these impacts would adversely affect specific industries such as construction and manufacturing. One commenter suggested the EPA consider regional differences that will impact system reliability and costs, such as the increased impacts on regions relying heavily on coal and oil and encourages cooperation between the EPA and state and federal energy and environmental regulators.

Response: The Agency has studied possible impacts on resource adequacy as a result of this rule, and has determined that these impacts should not be significant. Furthermore, industry, along with relevant federal agencies, has the tools needed to address any reliability concerns. The Agency has prepared an updated feasibility TSD in support of the final rule, which is in the docket for this rulemaking.[352] The Agency has considered impacts on a regional basis as part of its overall analyses done using the IPM; these results are documented in the RIA for the rule and in the feasibility TSD.

The EPA's analysis shows that retail electricity price increases will not fall disproportionately on a specific region. In fact, those regions experiencing the largest change in prices are projected to have retail electricity prices below the national average both in the absence of MATS and after the implementation of MATS. In Chapter 3 of the RIA, the EPA presents retail electricity prices by region in 2015, for both the base case and MATS policy case. The six regions that are projected to have retail electricity prices above the national average price in 2015 in the absence of MATS are projected to have increases that are below the national average increase following the implementation of MATS. Those regions that have projected retail electricity price increases that are above the national average are all projected to have retail electricity prices below the national average in the absence of MATS.

Comment: A commenter quoted National Mining Association statistics showing coal is responsible for $65.738 billion in annual economic activity, produces 1,798,800 jobs and $36.345 billion in annual labor income. The commenter reports that regions such as Appalachia, the Midwest and Rocky Mountain West will be significantly affected by the proposed rule, including increased unemployment. Other commenters stated that communities near existing coal-fired generation units will be especially hard-hit if the plants are permanently retired. The communities will suffer from job loss and diminished tax revenue.

Response: The Agency's analysis, as found in the RIA, shows that impacts to these regions are mixed. For Appalachia, coal production is projected to fall by 6 percent in 2015, while the Western coal producing region will experience a decrease of 3 percent in production in 2015. The Interior region is projected to see a 9 percent increase in production. Retail electricity prices are expected to increase by 1.3 percent to 6.3 percent in various parts of the country in 2015. Also, the estimated number of early retirements according to the Agency that may result from this rule is 4.7 GW in 2015, or less than 2 percent of all U.S. coal-fired capacity in that year. Thus, there may be some negative impacts from this rule in some regions, but these same regions will also experience some of the benefits, such as reduced premature mortality from less exposure to $PM_{2.5}$ emissions as shown in Chapter 5 of the RIA. As discussed previously, the EPA's analysis shows that retail electricity price increases will not fall disproportionately on a specific region. In fact, those regions experiencing the largest change in prices are projected to have retail electricity prices below the national average both in the absence of MATS and after the implementation of MATS.

The results of the EPA's employment analysis, found in Chapter 6 of the RIA, indicate that the final MATS has the potential to provide significant short-term employment opportunities, primarily driven by the high demand for new pollution control equipment. While the employment gains related to the new pollution controls are likely to be tempered by some losses due to certain coal retirements, some of these workers who lose their jobs due to plant retirements could find replacement employment operating the new pollution controls at nearby units. Finally, job losses due to reduced coal demand are expected to be offset by job gains due to increased natural gas demand, resulting in a small positive net change in employment due to fuel demand changes.

While shifts in employment are difficult for those directly affected, and the Agency remains concerned about the challenges job shifts can bring to the

[352] *See* "An Assessment of the Feasibility of Retrofits for the Mercury and Air Toxics Standards Rule" in the docket.

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individuals affected, Bureau of Labor Statistics data indicate that compliance with pollution control requirements is a relatively very small contributor to overall employment shifts in the U.S. economy. Specifically, the main cause of mass layoffs over the last four years according to 2007 to 2011 Bureau of Labor Statistics data is "lack of business demand," accounting for over 40 percent of the layoffs reported by industry. In contrast, all types of regulatory actions (including health, safety, and environmental) by all levels of government (Federal, State, local) combined were cited as the primary factor in only 0.2 percent of mass layoffs over the same period.[353]

d. Retirements of Coal-Fired EGUs and Shutdowns

Comment: A commenter discussed the economic factors behind EGU retirements. These factors include the cost of alternative generation using natural gas, the cost of implementing demand response measures that can be bid into capacity markets, and the cost of continuing to generate power from an existing unit. The commenter states that regardless of the costs associated with the Toxics Rule and other EPA electric power industry regulations, some power plants were already economically unsustainable. The commenter quotes M.J. Bradley, who points out, "[o]f the 122 coal units in PJM with capacity less than or equal to 200 MW, 35 failed to recover their avoidable costs and another 52 were close to not recovering those costs. Therefore, in PJM * * * in addition to approximately 10 GW of coal generation that has or will be retired during the 7 years from 2004 to 2011, another 11 GW faces a troubling economic outlook." The commenter provides confirmation of this by the most recent PJM capacity auction, where approximately 6.9 fewer GW of coal-fired capacity cleared the auction (1.85 fewer GW were offered) as compared with the prior year's auction, and an additional 4.836 GW of new demand response (energy efficiency) resources cleared the auction. Thus, the commenter states, some claims linking retirements to the MATS are overstated and misleading. The commenter gives the example of the American Electric Power attempt to link its planned plant closures to the MATS, but those plants already are slated to either close or to upgrade controls to comply with existing laws. The commenter goes on to quote three independent studies that support the finding that over 50 percent of the fleet is equipped with scrubbers and the number will increase to nearly ⅔ by 2015.

Response: The EPA agrees with the findings of the independent studies mentioned by the commenter.

e. Impacts on Mining

Comment: Multiple commenters mention the proposed rule's impact on mining. One commenter mentioned increasing energy costs for the U.S. mining industry, resulting in fewer projects and associated jobs, as well as increasing dependence on foreign mineral resources. Commenters see mining impacts being disproportionally large for lignite mines, which are dependent on their co-located lignite-fired power plants. The commenters state that if the plant closes, there is no market for the lignite and the mine will also close, displacing plant workers. These impacts are largest in Texas, the largest coal consuming state and fifth largest coal producing state, as well as a deregulated electricity market. One commenter pointed out that the Texas coal market provided a buffer against natural gas price volatility and in particular believes the proposed rule does not take into account the emission reductions already achieved by industry in general and their company in particular. A commenter stated that impacts will be magnified in Texas, since it is the largest coal consuming state and mines lignite. A commenter indicated they believe it is unclear the extent to which EPA includes the impacts on the mining industry that will result from this rule.

Response: The Agency presents impacts on the coal mining sector from this rule in the RIA. Given the modest increase in coal and other energy costs associated with the rule, the Agency does not expect widespread impacts on coal mining. The Agency's modeling accounts for all emission controls and programs installed and/or implemented up through December 2010, including those in Texas.

f. Flexible Regulations

Comment: Several commenters expressed concern over the potential impacts of the regulation and believe that the requirements should be more flexible in order to mitigate these impacts.

Response: The EPA believes the requirements of the final rule have been made as flexible as possible consistent with the CAA. The final rule allows some flexibility, including allowing averaging across units in the same subcategory at a facility, allowing for an option of an input or output standard for existing units, and allowing for alternative compliance options (*e.g.,* for coal, filterable PM or total non-mercury metallic HAP or individual HAP metals). In addition, the Agency is not prescribing specific technologies as part of this final rule, but instead requiring emissions limitations be met. This approach allows the industry to find the most cost-effective approach to meeting the requirements while ensuring considerable public health benefits.

g. Temporary vs. Permanent Jobs

Comment: A commenter expressed disagreement with the EPA prediction of new jobs created, because the commenter believes far more plants will shut down than the EPA predicts, resulting in higher job losses. The commenter also pointed out that while jobs running power plants are permanent, the jobs predicted to be created by the proposed rule are short term construction jobs, and will all occur in the same short timeframe for compliance. The commenter also stated that the EPA estimate does not include the opportunity cost of lost construction jobs due to new power plants that will not be constructed due to the proposed rules.

Response: The Agency believes that the employment impacts of the final rule will be small, as has been the case historically with regards to environmental regulation. The Agency does provide an estimate of the long-term employment impacts to the electric power sector in the RIA for the rule, and that estimate shows a range of impacts from 15,000 net jobs lost to 30,000 net jobs gained (all annual), but also recognizes important limitations to these estimates. The Agency's estimate of impacts to short-term jobs, including those in construction, accounts for both losses and gains that result from the rule. This is shown in Chapter 6 of the RIA.

Comment: Commenters believe that installation of new pollution controls would be a job-growth opportunity in their states because money spent on controls for power plants creates high-quality jobs in steel, cement and other materials, as well as in the assembling of the equipment as well as installing and operating it. A commenter shares the Alabama Fisheries Association estimate that the water-based recreation industry brings in over $1 billion per year to the state's economy though the state ranks third for imperiled fish with 61 bodies of water cited for Hg contamination. The commenter believes the HAP accumulating in the waterways

[353] U.S. Bureau of Labor Statistics, 2011. Extended Mass Layoffs in 2010. *http://www.bls.gov/mls/mlsreport1038.pdf.*

threatens the industry with permanent job-losses and lost revenue.

Response: The Agency agrees with the commenter that the reduction in HAP that will take place as a result of the rule over time will help to improve waterways in Alabama and thus help the water-based recreation in that state. More information on the benefits of Hg and other HAP reductions can be found in Chapter 4 of the RIA for the rule. The Agency also agrees with the commenter that the addition of control equipment for EGUs may stimulate employment in a variety of industries.

h. Natural Gas

Comment: A commenter states that natural gas use is only an option in places where infrastructure exists to supply sufficient natural gas to the EGU and other local needs and reports that year-round reliable gas delivery is rare due to requirements to meet the other needs. The commenter says that gas interruptions are prevalent in the winter, but can happen year-round, and the costs of establishing a natural gas line to a power plant can be tens of millions of dollars or more, and moving a plant to a gas source can take many years. The commenter describes the options for a Norwalk Harbor plant, and explains that the modifications are costly and difficult even before considering the modifications needed to alter the boiler and fuel supply system to allow natural gas combustion.

Response: The final rule does not prescribe either pollution control technologies to be used, nor does it dictate the types of fuels that should be burned. The requirements of the final rule are designed to allow industry to find the most cost-effective approach to addressing harmful emissions that are covered by this action. The Agency believes that cost-effective technologies exist today and have been deployed on many power plants, and utilities will be able to find intelligent solutions to address harmful emissions. The EPA has provided supporting information as part of the preamble and RIA for this rule, along with the feasibility TSD, which demonstrate the availability and performance of technologies to meet the requirements of the final rule.

Comment: A commenter discusses the factors that could lead to higher natural gas prices not currently reflected in the EPA impact projections, including industrial load and demand not rebounding to 2008 levels and the influence of liquefied natural gas exports. The commenter asks that the EPA address a variety of factors related to its natural gas assumptions.

Response: The Agency has fully documented its assumptions and framework for modeling natural gas in IPM for both the proposed and final MATS. This information can be found in Chapter 10 of the IPM documentation (*http://www.epa.gov/airmarkets/progsregs/epa-ipm/docs/v410/Chapter10.pdf*). The documentation provides a thorough overview of the natural gas module, describes the very detailed process-engineering model and data sources used to characterize North American conventional, unconventional, and frontier natural gas resources and reserves and to derive all the cost components incurred in bringing natural gas from the ground to the pipeline. Also documented are the resource constraints, liquefied natural gas (LNG), demand side issues, the natural gas pipeline network and capacity, procedures used to capture pipeline transportation costs, natural gas storage, oil and natural gas liquids (NGL) assumptions, and key gas market parameters.

i. Compliance Timeline and General Timeline

Comment: A commenter states that the proposed rule will require costs be passed on to consumers, meaning state public utility commissions will be flooded with requests for rate increases from utilities trying to recover expenditures. The short deadline will also result in a large number of extension requests made to state permitting authorities, further burdening them.

Response: The compliance date for this rule for existing sources will be 3 years and 60 days after publication of the final rule in the **Federal Register**, or approximately March 2015. Thus, there will be some time before the impacts of this rule such as any increase in retail electricity prices become a concern. It also should be noted that increases in retail electricity prices will be 3.1 percent on average in 2015, with a range regionally from 1.3 percent to 6.3 percent.

Comment: A commenter reports that they will need to install add-on pollution controls to meet the proposed emission standards as well as implement other physical or operational changes. The commenter expresses concern about the number of pre-construction steps that would be required, as well as the new construction activities and the challenges of scheduling sequence relative to interconnections and other tie-in considerations involved in compliance.

Response: The Agency has addressed concerns with the feasibility and timing of control installations in its report on the subject (*see* feasibility TSD contained in the docket for this rule).

Comment: Multiple commenters do not believe that labor availability will constrain control installation in the required timeframe and cites an Institute of Clean Air Companies (ICAC) response that it will not for these reasons:

1. The power sector has demonstrated ability to install large number of systems in short time period;
2. The majority of coal plans have installed control systems already;
3. Fewer resource and labor-intensive control options being used for compliance; and
4. End users have utilized cost reducing and implementation efficiency strategies for efficient deployment of technologies.

Another commenter states that a wide range of technical and economically feasible practices and technologies are available currently to meet the emission limits and are in use around the country.

Response: These comments are generally consistent with the conclusions of the Agency's analyses on feasibility of control installations for this rule as found in the feasibility TSD in the docket for this rulemaking.

j. Burden Outweighs Environmental Gain

Comment: Several commenters state that the EPA has no data relating to benefits from reducing non-mercury HAP, so the costs of the proposed rule exceed the HAP benefits by 29,000 times. One commenter states that the impact analysis was largely focused on Hg with little support for other HAP reductions and failed to provide account of true costs and benefits.

Response: While we are not able to monetize the benefits from reductions of non-mercury HAP that will take place, these important effects are discussed qualitatively in Chapter 4 of the RIA. The quantified benefits of this rule include the reductions in non-HAP emissions such as SO_2 and $PM_{2.5}$ that will occur as a co-benefit of this rule as modeled by EPA. The total benefits are estimated to outweigh the total annual costs of the rule by a margin of either 3 to 1 or 9 to 1, depending on the benefits estimate and discount rate used. These reductions are credible and are considerable in size. The estimates of these benefits reflect the latest scientific understanding on the subject. More information on the estimates and

the methodology for their preparation can be found in the RIA for the rule.

Comment: Several commenters consider the proposed rule to be the most expensive clean air rule ever. They point out the estimated $10.9 billion annual cost in 2015 and approximate 1,200 existing coal-fired EGUs affected, both of which were estimated by the EPA. Commenters believe the EPA's estimates are incorrect and the true cost will be far more, due to cumulative effects of all proposed power sector rules, and indirect costs from job losses, reduced productivity and competitiveness resulting from electricity costs. They ask the EPA to keep these high costs in mind when evaluating impacts of the proposed rule and consider the costs with respect to the benefits. One commenter requests that the EPA explain how its approach utilized "the best available techniques to quantify anticipated present and future benefits and costs as accurately as possible" and includes analyses by EIA, EEI, NERC, NERA, Credit Suisse, ICF, and Burns & McDonnell.

Response: As noted earlier, the Agency did not prepare a cumulative impact analysis to accompany the rule for the following reasons: (1) The various EO requirements that the Agency must comply with require us to estimate impacts specific to this rule; (2) decisionmakers and the public need to know the impacts specific to a particular rule in order to judge the merits of the regulation; and (3) estimates specific to a particular rule are more transparent than those from a cumulative impact analysis. A cumulative impact analysis lumps several regulations together and can potentially mask a high-cost/low benefit regulation among other rules that may have large net benefits. By analyzing each regulation separately, EPA makes clear statements about the impacts, costs, and benefits that are estimated as a result of this particular regulation.

This does not, however, mean EPA has failed to incorporate these regulations into this analysis. The inclusion of CSAPR and other regulatory actions (including federal, state, and local actions) in the IPM base case reflects the level of controls that are likely to be in place in response to other requirements apart from MATS. This base case provides meaningful projections of how the power sector will respond to the cumulative regulatory requirements for air emissions, while isolating the incremental impacts of MATS. These results are presented in Chapter 3 of the RIA.

Additionally, the Agency does reflect on the cumulative impacts of our regulations. In March 2011, EPA issued the Second Clean Air Act Prospective Report which assessed the benefits and costs of regulations pursuant to the 1990 Clean Air Act Amendments. The study examines the cumulative impact of these regulations (found at *http://www.epa.gov/air/sect812/feb11/summaryreport.pdf*). As shown in the report, the direct benefits from the 1990 Clean Air Act Amendments are estimated to reach almost $2 trillion for the year 2020, a figure that dwarfs the direct costs of implementation ($65 billion). The full report is at *http://www.epa.gov/air/sect812/prospective2.html.*

The direct benefits of the 1990 Clean Air Act Amendments and associated programs are estimated to significantly exceed their direct costs, which means economic welfare and quality of life for Americans were improved by passage of the 1990 Amendments. The wide margin by which benefits are estimated to exceed costs, combined with extensive uncertainty analysis, suggest it is very unlikely this result would be reversed using any reasonable alternative assumptions or methods. The analysis presented in the RIA for the current regulation uses a similar methodology.

The techniques employed by the Agency for generating benefits and costs, and consider the most recent and complete data available to the Agency. The EPA recognizes that the analyses have caveats and limitations, and we discuss our analyses and their caveats and limitations in the RIA for the rule, as well as in the benefits section of the preamble. The Agency has also revised the cost analyses for the final rule to reflect data received in public comments on the proposed rule, and costs are lower than when the rule was proposed.

k. Impact on State Regulators

Comment: Several commenters expressed concern over the burden imposed on state regulatory agencies by the rule.

Response: The Agency has estimated the costs of implementation of the rule to states that own EGUs affected by the rule, and has included this analysis in the RIA. The Agency has updated this analysis for the final rule and it is included in the RIA. While the EPA has not prepared an analysis of the impacts of the rule on state programs, the Agency does not believe the rule will be unduly burdensome to the state regulatory agencies. The EPA works closely with state regulatory authorities to ensure that the rules are implemented properly, and the Agency will continue to do so in support of this final rule.

Comment: A commenter states that the reductions in SO_2 and $PM_{2.5}$ required by the proposed rule will assist state and local air pollution control agencies to meet health-based air quality standards, reduce haze and improve visibility. The commenter points out that substantial reduction in emissions made by the very large sources under the proposed rule will lead to fewer pollution controls needed at smaller sources to meet health-based ambient air requirements. This is a far more cost-effective approach than controls at smaller facilities and is the lowest cost path to improved public health and a cleaner environment.

Response: The EPA acknowledges that the HAP standards in this final rule will lead to considerable co-benefit reductions in PM and SO_2.

l. Miscellaneous

Comment: A few commenters discussed the impact of the rule on the federal budget deficit. One commenter points out that the proposed rule will affect the federal budget in two ways:

1. Direct compliance costs to electric generating units (EGUs) owned by federal agencies; and

2. Pass-through compliance costs paid in the form of higher prices for electricity purchased by federal agencies.

Response: The Agency estimates the direct compliance costs to EGUs that are federally owned as part of the overall cost analysis completed for the proposal and disclosed in the RIA for the rule. The Agency does not provide an estimate of the impact on federal agencies from higher electricity prices associated with the rule, however. This type of analysis is not required under EO 12866 and statutory requirements.

H. Testing and Monitoring

Comment: Commenters raised numerous issues with the testing and monitoring requirements for initial and continuous compliance. The following discussion highlights the comments and responses to a number of the critical issues and describe where the comments have resulted in a significant rule change or where we disagreed with commenters' suggestions of issues or need for changes in the rule. Additional comments and responses are addressed in the Response to Comments document included in the docket for the final rule.

Test Methods. A number of commenters suggested that we should allow for the use of Method 5B to determine compliance with the PM emission limit. In addition, a number of

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commenters objected to the frequency of stack testing when used as the method for demonstrating continuous compliance. Commenters also objected to the requirement for testing one pollutant when the source was complying with an optional surrogate (or vice versa); for example, commenters objected to testing for HCl if a unit was complying with the optional SO_2 limit, or testing for metals if the unit was complying with the optional PM limit.

Response: Although Method 5B is specified for wet scrubber-controlled utility boilers under 40 CFR part 60, subparts D, Da and Db, we are excluding Method 5B for demonstrating compliance with the filterable PM emissions standard in this final rule. The extended high temperature heating of the filters prior to weighing as specified in Method 5B would introduce differences between the compliance test data and the data that underlie the filterable particulate standard. Because the test data that underlie and filterable particulate standard are based primarily on Method 29 and Method 5 data collected at 320 °F or comparable filterable particulate methods, we are specifying those same methods for determining compliance with the standard.

For stack test frequency, we modified the final rule to require quarterly testing to demonstrate continuous compliance. In addition, we agree that testing should be required only for the emission limits that your source is complying with, and, thus, the final rule does not require testing of both the pollutant and the surrogate.

Comment: Fuel Analysis Methods. A number of commenters raised various concerns with the fuel analysis methods specified in the proposed rule.

Response: Based on the comments received and a further review of the technical challenges associated with the proposed fuel analysis requirements, we have not finalized the proposed fuel analysis requirements. As the rule no longer requires operating limits based on fuel content or fuel analysis, the comments on this issue are largely moot. For LEEs, we agree that the proposed LEE ongoing eligibility requirements were overly burdensome and restrictive. As a result, existing solid or liquid fired units that qualify for Hg LEE status will be required to conduct a 30-day test for Hg using Method 30B each year. Neither fuel analysis nor adherence to an operating limit will be required. Should an annual test show ineligibility for LEE status, the source will revert to the requirements for Hg monitoring using CEMS or sorbent traps or, for oil-fired units, quarterly emissions testing. Existing solid or liquid fired units that qualify for non-mercury LEE status will be required to conduct a stack test every 3 years, and neither fuel analysis nor adherence to an operating limit will be required. Should the stack test show ineligibility for LEE status, the source will revert to using CEMS or PM CPMS or conducting quarterly emissions testing.

Comment: Operating Parameter Limits: Some commenters objected to the use of enforceable operating parameter limits, requested that the rule be more consistent with the compliance assurance monitoring program, and raised specific objections to certain parameters required for certain control devices. Commenters also raised concerns about a PM CEMS operating limit establishing a de facto more stringent PM emission limit than the one being tested for under the total PM standard in the proposal.

Response: We believe that continuous monitoring in the form of CEMS, sorbent trap monitoring systems, and PM CPMS, or frequent stack emissions testing are appropriate to ensure ongoing compliance with this final rule. We also agree with commenters that some of the monitoring provisions in the proposal may have been duplicative and unnecessary. In order to provide flexibility in the final rule, we have retained a source's ability to define an operating limit and to monitor using a PM CPMS as an option to periodic filterable PM emissions testing.

The final rule establishes the PM CPMS as an operating limit monitor and not a direct filterable PM emission monitoring requirement that meets PS 11 requirements. Although we recognize the importance of continued control device performance to ensure emissions minimization, we also are aware that other rules that apply to these units including, but not limited to, the Operating Permits rule, the Compliance Assurance Monitoring rule, the ARP rules, and the NSPS already require continuous monitoring in most cases. Those rules will remain in effect so the need to impose additional operating limits monitoring or CEMS on those units is much reduced.

The final rule also provides for the use of a PM CEMS to determine compliance with the filterable PM emission limit if the source elects to use this approach. In that case, the PM CEMS is used as the direct method of compliance and no additional testing is required other than tests that are required as part of satisfying the requirements in Performance Specification 11 in Appendix B to 40 CFR part 60 and Procedure 2 in Appendix F to part 60. The EPA provided this option in response to the comments in order to provide a straightforward direct measure of compliance that some sources may want to implement.

Comment: Hg CEMS. Commenters raised a number of technical concerns about Hg CEMS. Many commenters requested modifications so that the requirements would be more consistent with 40 CFR part 75 monitoring requirements. Some commenters questioned the ability of the technology to demonstrate compliance with emission limits at very low levels especially for new sources. Commenters also opposed high data availability requirements given that the technology is new and difficult to operate and maintain.

Response: We indicated in the proposed rule the intent to adopt CAMR-based requirements for Hg monitoring in place of the general 40 CFR part 63 performance specifications and QA requirements. With CAMR, these operating and reporting requirements for Hg CEMS went through notice and comment rulemaking for the same sources as covered by this final rule. Although CAMR was set aside on other grounds, these technical specifications and QA requirements reflect significant input from stakeholders and analysis by the EPA to establish an appropriate foundation for Hg monitoring at electric utilities under the CAA. For the final rule, we have made conforming changes to ensure that this intent is carried out effectively throughout the rule text and Appendix A, as well as including certain additional clarifications based on the input received in response to the proposed rule. We have also removed a cycle time test as unworkable for certain types of Hg CEMS.

The final rule provides the option for use of either Hg CEMS or sorbent trap monitoring systems. We believe the record clearly shows these to be proven technologies each providing certain advantages. For existing and some of the new unit standards, the level of the NIST-traceable Hg gas standards will be adequate and consistent with existing applications of Hg CEMS. For the lowest limits and other applications where an integrated sampling system offers advantages, affected facilities may opt to use sorbent trap monitoring systems to comply. There are data in the recent draft report entitled "Determining the Variability Of CMMS At Low Hg Levels,"[354] that demonstrate reasonable

[354] *http://www.icci.org/reports/10Laudal6A-1.pdf.*

performance of at least one Hg CEMS at Hg levels below 1.0 microgram per cubic meter (μg/m³) down to approximately 0.1 μg/m³. Finally, there is no specific minimum data availability requirement for Hg CEMS (or any other CMS required under this final rule). This issue is discussed further below.

Comment: SO_2 CEMS: Although commenters were generally supportive of the ability to use SO_2 CEMS for units with FGD installed to demonstrate compliance with an alternate SO_2 emission limit instead of the HCl emission limit, there were some concerns with aspects of the proposal. Commenters requested that the SO_2 monitoring requirements rely on 40 CFR part 75 given that their sources were already meeting those requirements and that this rule not establish any new requirements, especially a fourth linearity level and the application of 7-day calibration error tests for units with low concentrations (where 40 CFR part 75 provides an exemption). Commenters were also concerned that the rule language only allows the option where the FGD is operated "at all times" which seems to imply that the option is not allowed if the source ever bypasses the FGD for start-up, shutdown, or malfunction reasons.

Response: After reviewing the comments and assessing the need for an additional calibration gas at the emissions limit, we have removed this requirement from the final rule while retaining the requirement for a linearity check even for SO_2 monitors with low span values (≤ 30 ppm). A source can already report linearity tests for these units within the context of the existing ECMPS reporting without triggering any critical errors. This test can be accommodated within the current framework without causing issues for 40 CFR part 75 reporting. The requirement for a 7-day calibration error test is removed. For the "at all times" language, we have clarified this in the final rule. The intent is that the FGD be operated during all routine boiler operations, and not operated intermittently, seasonally, or on some other non-fulltime basis.

Comment: HCl CEMS. In general, commenters argued that HCl CEMS do not have an approved performance specification and are not widely demonstrated as a proven technology. Those concerns were also mentioned for HF CEMS.

Response: We disagree with commenters' contention that continuous HCl monitoring is premature or not available for the measurement at the emission limits set in the final rule. HCl CEMS are being used on source categories such as municipal waste combustors and EGUs. We have reviewed HCl CEMS vendor technology claims and found sufficient capability to support this rule requirement. We are engaged with representative stakeholders to develop a generic performance specification for HCl CEMS scheduled for completion in time to be responsive to compliance with this rule.

The final rule provides several options for HCl and/or HF monitoring including:

(1) Using Fourier Transform Infrared (FTIR)-based HCl CEMS and/or HF CEMS complying with Appendix B to the rule which relies on PS 15,

(2) Seeking approval for an alternative HCl monitoring procedure through 40 CFR 63.7(f),

(3) Monitoring compliance continuously with the alternate SO_2 emission limit at coal-fired or other solid fuel affected facilities equipped with FGD technology for SO_2, and

(4) Quarterly reference method testing.

Including these options in the final rule provides flexibility to adopt CEMS monitoring options as the technology continues to mature and the new, non-technology-specific EPA performance specifications becomes available.

Comment: Bypass Stacks. Several commenters raised concerns about the technical feasibility of monitoring bypass stacks with a CEMS.

Response: We have modified the bypass stack monitoring requirements. Under 40 CFR part 75, we allow the use of a maximum potential concentration value for reporting when emissions are vented to a bypass stack. That approach works within the context of an emissions trading program, but is not appropriate when evaluating compliance with a specific emission limit. Thus, we have provided two other options. One is to monitor the bypass stack, consistent with the final rule. The other is to treat any hours of bypass stack emissions as periods of monitor downtime and hours of deviation from the monitoring requirements. Note that a source's units must continue to meet their 30-boiler operating day emissions limits during malfunction periods.

Comment: 40 CFR part 75 Issues. There were a number of general comments about the value of relying on 40 CFR part 75 requirements, including elements such as conditional data validation. The commenters generally agreed that the 40 CFR part 75 bias test and bias adjustment factor, and the 40 CFR part 75 substitute data provisions should not apply. Instead of substitute data, many commenters suggested that we needed to clarify the valid reasons for monitor downtime and establish an appropriate minimum data availability requirement.

Response: We have attempted to harmonize the CEMS requirements in this final rule with those under 40 CFR part 75 wherever appropriate. One of those examples is the inclusion of conditional data validation for Hg CEMS. We disagree that this final rule needs a minimum data availability requirement. We have not included any specific minimum data availability requirement for CEMS or other monitoring in this final rule nor do we provide a specific tool for data substitution. We believe that there are other provisions in the final rule to provide incentives to conduct monitoring in a manner consistent with good air pollution control practices and to provide data sufficient to demonstrate compliance with a relatively long-term (30-boiler operating day) emissions rate limit. We agree that data quality certainty associated with any calculated value decreases with the collection of less data such as would occur with extended periods of monitoring system downtime. Even so, we believe also that it is necessary and critical for compliance with the regulation that a source use all measured data collected during an averaging period to assess compliance regardless of any periods of missing data. Sources should not disqualify any data otherwise meeting required data quality requirements simply because there were data missing for other hours or days of the averaging period.

Instead of a minimum data availability threshold that would invalidate data collected for some averaging periods because one did not collect data for at least a specified percent of an averaging time, the final rule requires that a source report as deviations to the rule failure to collect data during required periods if these deviations are not covered by exceptions allowed in the final rule.

On the issue of applying a data substitution procedure to represent actual emissions or pollution control performance, we are not requiring data substitutions under this rule. We believe, however, that defensibility concerns make it incumbent on the source to collect and evaluate other information in accordance with 40 CFR section 63.6(f)(3) during periods of monitoring downtime to assure compliance with the applicable emissions limitations and standards.

We believe that enforcement authorities also can and should determine whether a source is meeting any monitoring system operating

requirements. Should the source or the enforcement authority be concerned about the representativeness of data such as during periods of missing data, either one may consider collecting information through other means (*e.g.,* supplemental emissions testing) to fill data gaps not only because such gaps are deviations from the rule but such gaps can lead to uncertainty about compliance status.

We further believe that the final rule provides sufficient means to ensure CMS performance and ongoing compliance without specifying an arbitrary numerical minimum data availability or data substitution requirement. We believe that specifying failure to collect required or otherwise excepted data as a deviation from the rule will provide the necessary incentive to collect data sufficient to demonstrate compliance with the limits in the final rule.

Comment: Recordkeeping. Several commenters opposed the requirements related to maintaining records on site and for 5 years.

Response: We believe the recordkeeping and retention requirements are consistent with other requirements already in place, specifically 40 CFR 63.10 (b).

In addition, the 5-year retention period is the general rule for all recordkeeping for all sources under the part 70 operating permits program. Given that the General Provisions for 40 CFR part 63 and part 70 already establish a 5-year retention period, we believe it is justified in using those precedents for the retention periods under this subpart. If we stayed silent on retention period in this subpart, the General Provisions would provide for the 5-year retention as would the part 70 requirements. Thus, this action does not establish any new retention requirements, but merely confirms that the existing retention requirements apply.

Comment: Electronic Reporting. In the proposed rule, we requested comment on using ECMPS for reporting under this rule, as well as other options including the ERT. Commenters generally supported the use of ECMPS, especially for CEMS data. Some commenters requested an additional rulemaking on the specific data elements to be collected. There were some concerns raised about the ERT given experience during the 2010 ICR process during the development of this rule.

Response: We recognize that emissions reporting for continuously measured pollutants (SO_2, NO_X, etc.) and for periodically measured pollutants (PM, HAP metals, etc.) have different data demands. We recognize that minor revisions of the ECMPS will fulfill our data needs for most continuously measured pollutants and we will make these modifications for receipt of the additional CEMS data. We also recognize the need for substantial modifications to the ECMPS to accommodate the data needs for periodically measured pollutants and certain CEMS data such as PM CEMS data and possibly HAP metals CEMS data. Although major modifications of the ECMPS would be required for periodic compliance tests by isokinetic and instrumental test methods (as well as certain types of CEMS), only minor revisions are required of the ERT to receive these tests. We are implementing the changes in the ERT that are required to provide the software tools to implement the delivery of these performance test data to us.

The electronic submission of compliance test reports to us through the Central Data Exchange (CDX) is not solely for the purpose of developing improved emissions factors as some commenters assert. Although populating WebFIRE will allow us to improve emissions factors, we intend to use data stored in WebFIRE as the primary location for compliance test reports for use by regulatory authorities. The electronic submission of compliance test reports is a continuation of our efforts to bring the submission and sharing of environmental data into the modern age. The storage of this compliance data in our WebFIRE provides a convenient location which is already used to store source test data.

As federal and state and local agencies' data systems mature, information provided through the ERT will be used to populate these data systems. We are currently upgrading the AIRS Facility System and expect to replace manually entered information with electronic population from the ERT. We are also working with several state and local agencies to adopt the use of the ERT for delivery of compliance test reports. The ERT is also much improved since the version used during the 2010 ICR process, and there is no expectation that the information to be reported under this final rule will be as extensive as some of the data reported for the 2010 ICR purposes.

We disagree that a separate and independent regulatory action is required to implement electronic reporting for selected regulated sources. Each of these regulatory actions for selected source categories provides ample notice and the opportunity for individuals to provide comment. We also disagree that the system to receive the compliance data must be operational prior to establishing the requirement for regulated sources to submit compliance data electronically. We are on track to have the capability to receive electronic compliance tests through our CDX in sufficient time to receive all utility source test reports required by this final rule.

We do plan a separate and independent regulatory action to implement electronic reporting for regulated entities which are covered by past and future rules. Although we have provided draft procedures for the development of emissions factors, that effort is an ancillary effort to the electronic delivery of compliance test reports. It is our intention to convert to the electronic delivery and storage of all air emissions compliance source test data. With this transition, we believe this valuable information will be more readily available not only for compliance purposes but also for a variety of other uses.

I. Emissions Averaging

Comment: In response to our request for comments on the suitability of emissions averaging and need for a discount factor, we received a range of suggestions, including requests for clarification regarding eligibility, points for and against the need for a discount factor, and suggestions to ease implementation.

Response: We are finalizing that owners and operators of existing affected sources may demonstrate compliance by emissions averaging for EGUs at the affected source that are within a single subcategory and that rely on emissions testing as the compliance demonstration method. See section VI of thie preamble for a fuller discussion.

J. LEE Criteria

Comment: A commenter supported the LEE provisions but believed one of the LEE eligibility criteria should set at 29.0 lb/year, rather than 22.0 lb/year. The commenter suggested 29.0 lb/year to be an equally reasonable cut point, especially since that value matches the low mass emitter Hg monitoring cutoff in CAMR and the low mass emitter Hg monitoring cutoff that several states have adopted, including Illinois, 35 Ill. Admin. Code section 225.240(a)(4). (*See, e.g.,* Colorado (5 Colo. Code Regs. section 1 00 1–8, Reg. No.6, part B, Section VIII.B.l0); Michigan (Mich. Admin. Code R. 336.2160); Montana (Mont. Admin. R. 17.8771(12))). Further, a LEE cutoff of 29.0 lb would eliminate conflicts and confusion with low mass emitter provisions in existing state Hg

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programs and significantly reduce compliance costs and burdens for the additional qualifying units without adversely affecting compliance assurance with the EGU NESHAP Hg emission limits or materially increasing the number of potential qualifying LEEs. Given the many other costly burdens that the rule would impose, the benefit of LEE to a qualifying unit is not insignificant.

Response: The Agency reviewed the commenter's suggestions, and one of the LEE eligibility criteria in the rule has been revised from 22.0 to 29.0 lb of Hg per year. The Agency finds the result of consistency with existing state regulations outweighs the two percent difference in nationwide Hg mass emissions, from 5 percent to 7 percent, for LEE eligibility.

VIII. Background Information on the NSPS

A. What is the statutory authority for this final NSPS?

New source performance standards implement CAA section 111(b), and are issued for categories of sources which cause, or contribute significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare. Section 111 of the CAA requires that NSPS reflect the application of the best system of emissions reductions which (taking into consideration the cost of achieving such emissions reductions, any non-air quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated. The level of control prescribed by CAA section 111 historically has been referred to as "Best Demonstrated Technology" or BDT. In order to better reflect that CAA section 111 was amended in 1990 to clarify that "best systems" may or may not be "technology," the EPA is now using the term "best system of emission reduction" or BSER. As was done previously in analyzing BDT, the EPA uses available information and considers the emission reductions and incremental costs for different systems available at reasonable cost. Then, the EPA determines the appropriate emission limits representative of BSER. Section 111(b)(1)(B) of the CAA requires EPA to periodically review and revise the standards of performance, as necessary, to reflect improvements in methods for reducing emissions.

B. What is the regulatory authority for the final rule?

The current standards for steam generating units are contained in the NSPS for EGUs (40 CFR part 60, subpart Da), industrial-commercial-institutional steam generating units (40 CFR part 60, subpart Db), and small industrial-commercial-institutional steam generating units (40 CFR part 60, subpart Dc).

The NSPS for EGUs (40 CFR part 60, subpart Da) were originally promulgated on June 11, 1979 (44 FR 33580) and apply to units capable of firing more than 73 megawatts (MW) (250 MMBtu/h) heat input of fossil fuel that commenced construction, reconstruction, or modification after September 18, 1978. The NSPS for EGUs also apply to industrial-commercial-institutional cogeneration units that sell more than 25 MW and more than one-third of their potential output capacity to any utility power distribution system. The most recent significant amendments to emission standards under 40 CFR part 60, subpart Da, were promulgated in 2006 (71 FR 9866) resulting in new PM, SO_2, and NOP_2 limitations for 40 CFR part 60, subpart Da units.

The NSPS for industrial-commercial-institutional steam generating units (40 CFR part 60, subpart Db) apply to units for which construction, modification, or reconstruction commenced after June 19, 1984, that have a heat input capacity greater than 29 MW (100 MMBtu/h). Those standards were originally promulgated on November 25, 1986 (51 FR 42768) and also have been amended since the original promulgation to reflect changes in BSER for these sources.

The NSPS for small industrial-commercial-institutional steam generating units (40 CFR part 60, subpart Dc) were originally promulgated on September 12, 1990 (55 FR 37674) and apply to units with a maximum heat input capacity greater than or equal to 2.9 MW (10 MMBtu/h) but less than 29 MW (100 MMBtu/h). Those standards apply to units that commenced construction, reconstruction, or modification after June 9, 1989.

IX. Summary of the Final NSPS

The final rule amends the emission standards for SO_2, NOP_2, and PM in 40 CFR part 60, subpart Da. Only those units that begin construction, modification, or reconstruction after May 3, 2011, will be affected by the final rule. Compliance with the emission limits of the final rule will be determined using testing, monitoring, and other compliance provisions similar to those set forth in the existing standards. In addition to the emissions limits contained in the final rule, we also are including several technical clarifications and corrections to existing provisions of the subparts.

A. What are the requirements for new EGUs (40 CFR part 60, subpart Da)?

The filterable PM emissions standard for new and reconstructed EGUs is 11 nanograms per joule (ng/J) (0.090 pound per megawatt hour (lb/MWh)) gross energy output regardless of the type of fuel burned. The PM emissions standard for modified EGUs is essentially equivalent to the existing requirements of 13 ng/J (0.015 lb/MWh) heat input regardless of the type of fuel burned. Compliance with this emission limit can be determined using testing, monitoring, and other compliance provisions similar to those for PM standards set forth in the existing rule. While not required, PM CEMS may be used as an alternative method to demonstrate continuous compliance and as an alternative to opacity and parameter monitoring requirements.

The SO_2 emission limit for new and reconstructed EGUs is 130 ng/J (1.0 lb/MWh) gross energy output or 97 percent reduction regardless of the type of fuel burned with one exception. The EPA neither proposed to amended the SO_2 standard for coal refuse-fired EGUs, not reopened the issue of whether coal refuse-fired EGUs is an appropriate subcategory, and, therefore, that emissions standard is unchanged. The SO_2 emission limit for modified EGUs burning any fuel is 180 ng/J (1.4 lb/MWh) gross energy output or 90 percent reduction. Compliance with the SO_2 emission limit is determined on a 30-boiler operating day rolling average basis using a CEMS to measure SO_2 emissions and following the compliance provisions in the proposed rule.

The NO_X emission limit for new and reconstructed EGUs is 88 ng/J (0.70 lb/MWh) gross energy output regardless of the type of fuel burned with one exception. The exception is that for new and reconstructed EGUs that burn over 75 percent coal refuse (by heat input), the NO_X emission limit is 110 ng/J (0.85 lb/MWh) gross energy output. The NO_X limit for modified EGUs is 140 ng/J (1.1 lb/MWh) gross energy output regardless of the type of fuel burned in the unit. Compliance with this emission limit is determined on a 30-boiler operating day rolling average basis using testing, monitoring, and other compliance provisions similar to those in the proposed rule.

As an alternative to the NO_X standard, owners/operators of new and reconstructed EGUs may elect to comply with a combined NO_X/CO standard of 140 ng/J (1.1 lb/MWh) with one exception. The exception is that for new

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and reconstructed EGUs that burn over 75 percent coal refuse (by heat input) on an annual basis, the NO_X/CO emission limit is 160 ng/J (1.3 lb/MWh) gross energy output. Finally, owners/operators of modified EGUs may elect to comply with a combined NO_X/CO standard of 190 ng/J (1.5 lb/MWh).

B. Additional Amendments

See the Response to Comments document.

X. Summary of Significant Changes Since Proposal

A. Emission Limits

The proposal included a combined (filterable plus condensable) PM standard. The final standard is based only on filterable PM. No standard is being established for condensable PM. The rationale for this is set forth in the Response to Comments (RTC) document for this final rule (the NSPS Final Rule RTC).

The proposal requested comment on whether the final standard should include a stand-alone NO_X standard or a combined NO_X/CO standard. In response to comments we received and our own further evaluation of the situation, the final standard includes a stand-alone NO_X standard and an optional, but not required, combined NO_X/CO standard as an alternative to the amended NO_X standard. Again, our full rationale for this is set forth in the NSPS Final Rule RTC. The proposal also included a request for comment on whether the standard should be based on gross or net output. In response to comments we received and our own further evaluation of the situation, the final standards are based on an amended definition of gross output with an optional net output-based standard. This too is addressed more fully in the NSPS Final Rule RTC.

The proposal included alternate emission standards for commercial demonstration projects. Proposed commercial demonstrations included pressurized fluidized beds, multi-pollutant control technologies, and advanced combustion controls. The final rule includes the commercial demonstration permit exemption for pressurized fluidized beds and multi-pollutant control technologies, but not advanced combustion controls. Advanced combustion controls are applicable to existing facilities and the exemption is not necessary to further the development of the technology.

B. Requirements During Startup, Shutdown, and Malfunction

For startup and shutdown, the requirements for PM have changed since proposal. For periods of startup and shutdown, the EPA is finalizing work practice standards for PM in lieu of numeric emission limits. Emissions incurred during periods of startup and shutdown for PM are not used in demonstrations of compliance with the 30-boiler operating day rolling average period applicable for numeric emission standards.

XI. Public Comments and Responses to the Proposed NSPS

See the Response to Comments document.

XII. Impacts of the Final Rule

The EPA anticipates significant public health and environmental benefits from the rule as a direct result of the substantial reduction in the emissions of several pollutants, including SO_2, Hg, acid gases and fine particles and metals. For example, exposure to Hg can damage the developing nervous system, which can impair children's ability to think and learn, and fine particles can cause adverse cardiovascular effects. Further, reducing Hg deposition to ecosystems will benefit wildlife including fish, birds, and mammals. Fish and fish-eating birds, such as the common loon, and mammals suffer reproductive, survival, and behavioral impairments due to mercury exposure. These effects have also been observed in insect-eating and wading birds, including egrets and white ibis. Reductions of emissions targeted by this rule also will slow acidification and eutrophication of water bodies.

Additionally, the EPA anticipates significant non-health, non-ecological benefits from this rule. The fine particle and SO_2 emission reductions achieved by this rule will improve visibility, which is especially important for our national parks. Emissions reductions from this rule will also avoid an estimated $360 million (in $2007) of climate-related costs, such as agricultural productivity and property damage from increased flood risks.

A. What are the air impacts?

The EPA anticipates significant emission reductions under the final rule from coal-fired EGUs, which are of particular interest due to their share of total power sector emissions. In 2015, annual HCl emissions are projected to be reduced by 88 percent, Hg emissions reduced by 75 percent, and $PM_{2.5}$ emissions reduced by 19 percent from coal-fired EGUs greater than 25 MW. In addition, the EPA projects SO_2 emission reductions of 41 percent, and annual CO_2 reductions of 1 percent from coal-fired EGUs greater than 25 MW by 2015, relative to the base case. *See* Table 7.

TABLE 7—SUMMARY OF EMISSION REDUCTIONS FROM COAL-FIRED EGUS GREATER THAN 25 MW (TPY)

	SO_2 (million tons)	NO_X (million tons)	Mercury (tons)	HCl (thousand tons)	$PM_{2.5}$ (thousand tons)	CO_2 (million metric tonnes)
Base Case	3.3	1.7	27	45	270	1,906
MATS	1.9	1.7	7	6	218	1,882
Change	−1.4	0.0	−20	−40	−52	−23

Note: Numbers may not add due to rounding.

The reductions in this table do not account for reductions in other HAP which will occur as a result of this rule. For instance, the fine particulate reductions presented above only partly reflect reductions in many heavy metal particulates, and the HCl reductions above only partly reflect reductions of all acid gases. This rule will also result in additional HAP reductions from oil-fired EGUs, which are covered by the rule but are not included in the EPA's analysis of emission reductions.

B. What are the energy impacts?

The EPA projects that approximately 4.7 GW of coal-fired generation (less than 2 percent of all coal-fired capacity and 0.5 percent of total generation capacity in 2015) may be uneconomic to maintain and may be removed from operation by 2015. These units are predominantly smaller, less frequently used, and are dispersed throughout the country. If current forecasts of either natural gas prices or electricity demand were revised in the future to be higher, that would create a greater incentive to

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make further investments in these facilities and keep these units operational.

The final rule has other important energy market implications. Average nationwide retail electricity prices are projected to increase in the contiguous U.S. by 3.1 percent in 2015. The average delivered coal price is projected to increase by less than 2 percent in 2015 as a result of shifts within and across coal types. The EPA also projects that electric power sector-delivered natural gas prices will increase by between 0.3 and 0.6 percent over the 2015 to 2030 timeframe, on average, and that natural gas use for electricity generation will increase by less than 200 billion cubic feet (BCF) in 2015. These impacts are well within the range of price variability that is regularly experienced in natural gas markets. Finally, the EPA projects coal production for use by the power sector, a large component of total coal production, will decrease by 10 million tons in 2015 from base case levels, which is about 1 percent of total coal produced for the electric power sector in that year.

C. What are the cost impacts?

The power industry's "compliance costs" are represented in this analysis as the change in electric power generation costs between the base case and policy case in which the sector pursues pollution control approaches to meet the MATS emission standards. In simple terms, these costs are the resource costs of direct power industry expenditures to comply with the EPA's requirements.

The EPA projects that the annual incremental compliance cost of MATS is $9.6 billion in 2015 ($2007). The annualized incremental cost is the projected additional cost of complying with the rule in the year analyzed, and includes the amortized cost of capital investment and the ongoing costs of operating additional pollution controls, needed new capacity, shifts between or amongst various fuels, and other actions associated with compliance.

The total incremental compliance cost includes compliance costs modeled in IPM of $9.4 billion, costs modeled outside of IPM for oil-fired EGUs of $56 million, and monitoring, reporting, and recordkeeping costs of $158 million.

D. What are the economic impacts?

For this final rule, EPA analyzed the costs using the IPM. The IPM is a dynamic linear programming model that can be used to examine the economic impacts of air pollution control policies for a variety of HAP and other pollutants throughout the contiguous U.S. for the entire power system.

Documentation for IPM can be found in the docket for this rulemaking or at *http://www.epa.gov/airmarkets/progsregs/epa-ipm/index.html.*

The EPA performed a screening analysis for impacts on small entities by comparing compliance costs to sales/revenues (*e.g.*, sales and revenue tests). The EPA's analysis can be found in Chapter 7 of the RIA for this rule. The EPA has also prepared a Final Regulatory Flexibility Analysis (FRFA) that discusses alternative regulatory or policy options that minimize the rule's small entity impacts.

Although a stand-alone analysis of employment impacts is not included in a standard cost-benefit analysis, the current economic climate has led to heightened concerns about potential job impacts. Executive Order 13563 specifically states that our "regulatory system must protect public health, welfare, safety, and our environment while promoting economic growth, innovation, competitiveness, and *job creation*" (emphasis added).

Under conditions of full employment, it is conventional to assume that regulations will merely shift jobs from one sector to another, without having a material effect on employment levels. Potential employment effects are of greater concern in the current economic climate, with high levels of employment, because of the risk that displaced workers may not find alternative jobs. In addition, regulations that result in firms hiring workers, in order to ensure compliance, may have a positive effect on employment.

During sustained periods of excess unemployment, the opportunity cost of labor required by regulated sectors to bring their facilities into compliance with an environmental regulation may be lower than it would be during a period of full employment (particularly if regulated industries employ otherwise idled labor to design, fabricate, or install the pollution control equipment required under this final rule). Consistent with EO 13563, the EPA includes estimates of job impacts associated with the final rule. In the electricity sector, the EPA estimates that the net employment effect will range from −15,000 to +30,000 jobs, with a central estimate of +8,000. The EPA also presents an estimate of short-term employment effects as a result of increased demand for pollution control equipment.

The results of this analysis, found in Chapter 6 of the RIA, indicate that the final rule has the potential to provide increases in short-term employment in the environmental industry, primarily driven by the high demand for new pollution control equipment. Overall, the results suggest that the final rule could support a net of roughly 46,000 job years[355] in direct employment impacts in 2015.

There are other employment effects that cannot be estimated quantitatively at this time. The employment gains related to the new pollution controls are likely to be tempered by some losses due to certain coal retirements. On the other hand, some of those workers who lose their jobs due to plant retirements could find alternative employment operating the replacement electricity generating equipment or new pollution controls at nearby units. Finally, job losses due to reduced coal demand may be offset by job gains due to increased natural gas demand, potentially resulting in a positive net change in employment due to fuel demand changes.

The basic approach to estimate these employment impacts involved using IPM projections from the final rule analysis, in particular the amount of existing coal-fired capacity that is projected to be retrofit with pollution control technologies. These data, along with data on labor and resource needs of new pollution controls and labor productivity from engineering studies and secondary sources, are used to estimate employment impacts for the pollution control industry in 2015. For more information, please refer to Chapter 6 and appendix 6B in the RIA.

The EPA relied on Morgenstern, *et al.,* (2002), to identify three economic mechanisms by which pollution abatement activities can influence jobs in the regulated sector separately from the short-term employment effects:

- Higher production costs raise market prices, higher prices reduce consumption, and employment within an industry falls ("demand effect");
- Pollution abatement activities require additional labor services to produce the same level of output ("cost effect"); and
- Post-regulation production technologies may be more or less labor intensive (i.e., more/less labor is required per dollar of output) ("factor-shift effect").

Using plant-level Census information between the years 1979 and 1991,

[355] Numbers of job years are not the same as numbers of individual jobs, but represents the amount of work that can be performed by the equivalent of one full-time individual for a year (or FTE). For example, 25 job years may be equivalent to five full-time workers for five years, 25 full-time workers for one year, or one full-time worker for 25 years.

Morgenstern,*et al.,* estimate the size of each effect for four polluting and regulated industries (petroleum, plastic material, pulp and paper, and steel). On average across the four industries, each additional $1 million spent on pollution abatement results in a small net increase of 1.55 jobs; the estimated effect is not a statistically different from zero. As a result, the authors conclude that increases in pollution abatement expenditures may increase employment in the relevant sectors and do not necessarily cause economically significant employment changes. The conclusion is similar to that of Berman and Bui (2001) who found that increased air quality regulation in Los Angeles did not cause large employment changes.[356] For more information, please refer to Chapter 6 of the RIA for this final rule.[357]

In the directly affected sector, the EPA estimates that the net employment effect will range from −15,000 to +30,000 jobs, with a central estimate of +8,000. The ranges of job effects for the electricity sector, as calculated using the Morgenstern,*et al.,* approach are listed in Table 8.

TABLE 8—RANGE OF JOB EFFECTS FOR THE ELECTRICITY SECTOR

	Estimates using Morgenstern, *et al.,* (2001)			
	Demand effect	Cost effect	Factor shift effect	Net effect
Change in Full-Time Jobs per Million Dollars of Environmental Expenditure [a].	−3.56	2.42	2.68	1.55.
Standard Error	2.03	0.83	1.35	2.24.
EPA estimate for Final Rule [b]	−39,000 to +2,000	+4,000 to +21,000	+200 to +27,000	−15,000 to +30,000.

[a] Expressed in 1987 dollars. *See* footnote a from Table 6–2 of the RIA for inflation adjustment factor used in the analysis.
[b] According to the 2007 Economic Census, the electric power generation, transmission and distribution sector (NAICS 2211) had approximately 510,000 paid employees.

The EPA recognizes there may be other job effects that are not considered in the Morgenstern,*et al.,* study. Although EPA has considered some economy-wide changes, we do not have sufficient information to quantify other job effects associated with this rule.

E. What are the benefits of this final rule?

1. Benefits of Reducing HAP Emissions

a. Human Health and Environmental Effects Due to Exposure to MeHg. In this section, we provide a qualitative description of human health and environmental effects due to exposure to MeHg. The NAS Study (NRC, 2000) provides a thorough review of the effects of MeHg on human health. Many of the peer-reviewed articles cited in this section are publications originally cited in the NAS Study. In addition, the EPA has conducted literature searches to obtain other related and more recent publications to complement the material summarized by the NAS in 2000.

b. Neurologic Effects of Exposure to MeHg. In its review of the literature, the NAS found neurodevelopmental effects to be the most sensitive and best documented endpoints and concluded that they are appropriate for establishing an RfD (NRC, 2000); in particular NAS supported the use of results from neurobehavioral or neuropsychological tests. The NAS Study (NRC, 2000) noted that studies in animals reported sensory effects as well as effects on brain development and memory functions and support the conclusions based on epidemiology studies. The NAS noted that their recommended neurodevelopmental endpoints for an RfD are associated with the ability of children to learn and to succeed in school. They concluded the following: "The population at highest risk is the children of women who consumed large amounts of fish and seafood during pregnancy. The committee concludes that the risk to that population is likely to be sufficient to result in an increase in the number of children who have to struggle to keep up in school."

c. Cardiovascular Impacts of Exposure to MeHg. The NAS summarized data on cardiovascular effects available up to 2000. Based on these and other studies, the NAS Study concluded that "Although the data base is not as extensive for cardiovascular effects as it is for other end points (*i.e.,* neurologic effects) the cardiovascular system appears to be a target for MeHg toxicity in humans and animals." The report also stated that "additional studies are needed to better characterize the effect of MeHg exposure on blood pressure and cardiovascular function at various stages of life."

Additional cardiovascular studies have been published since 2000. The EPA did not develop a quantitative dose-response assessment for cardiovascular effects associated with MeHg exposures, as there is no consensus among scientists on the dose-response functions for these effects. In addition, there is inconsistency among available studies as to the association between MeHg exposure and various cardiovascular system effects. The pharmacokinetics of some of the exposure measures (such as toenail Hg levels) are not well understood. The studies have not yet received the review and scrutiny of the more well-established neurotoxicity data base.

d. Genotoxic Effects of Exposure to MeHg. The Mercury Study noted that MeHg is not a potent mutagen but is capable of causing chromosomal damage in a number of experimental systems. The NAS Study indicated that evidence that human exposure to MeHg causes genetic damage is inconclusive; they note that some earlier studies showing chromosomal damage in lymphocytes may not have controlled sufficiently for potential confounders. One study of adults living in the Tapajós River region in Brazil (Amorim*et al.,* 2000) reported a direct relationship between MeHg concentration in hair and DNA damage in lymphocytes, as well as effects on chromosomes. Long-term MeHg exposures in this population were believed to occur through consumption of fish, suggesting that genotoxic effects (largely chromosomal aberrations) may result from dietary, chronic MeHg exposures similar to and above those

[356] For alternative views in economic journals, see Henderson (1996) and Greenstone (2002).

[357] It should be noted that if more labor must be used to produce a given amount of output, then this implies a decrease in labor productivity. A decrease in labor productivity will cause a short-run aggregate supply curve to shift to the left, and businesses will produce less, all other things being equal.

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seen in the populations studied in the Faroe Islands and Republic of Seychelles.

e. Immunotoxic Effects to Exposure to MeHg. Although exposure to some forms of Hg can result in a decrease in immune activity or an autoimmune response (ATSDR, 1999), evidence for immunotoxic effects of MeHg is limited (NRC, 2000).

f. Other Hg-Related Human Toxicity Data. Based on limited human and animal data, MeHg is classified as a "possible" human carcinogen by the International Agency for Research on Cancer (IARC, 1994) and in IRIS (USEPA, 2002). The existing evidence supporting the possibility of carcinogenic effects in humans from low-dose chronic exposures is tenuous. Multiple human epidemiological studies have found no significant association between Hg exposure and overall cancer incidence, although a few studies have shown an association between Hg exposure and specific types of cancer incidence (*e.g.,* acute leukemia and liver cancer) (NAS, 2000).

Some evidence of reproductive and renal toxicity in humans from MeHg exposure exists. However, overall, human data regarding reproductive, renal, and hematological toxicity from MeHg are very limited and are based on studies of the two high-dose poisoning episodes in Iraq and Japan or animal data, rather than epidemiological studies of chronic exposures at the levels of interest in this analysis.

g. Ecological Effects of Hg. Deposition of Hg to watersheds can also have an impact on ecosystems and wildlife. Mercury contamination is present in all environmental media, with aquatic systems experiencing the greatest exposures due to bioaccumulation. Bioaccumulation refers to the net uptake of a contaminant from all possible pathways and includes the accumulation that may occur by direct exposure to contaminated media as well as uptake from food.

A review of the literature on effects of Hg on fish [358] reports results for numerous species including trout, bass (large and smallmouth), northern pike, carp, walleye, salmon, and others from laboratory and field studies. The effects of MeHg in fish are reproductive in nature. Although we cannot determine at this time whether these reproductive deficits are affecting fish populations across the U.S. it should be noted that it would seem reasonable that over time reproductive deficits would have an effect on populations.

Mercury also affects avian species. In previous reports [359] much of the focus has been on large piscivorous species, in particular the common loon. According to Evers,*et al.,* significant adverse effects from Hg on breeding loons have been found to occur, including behavioral (reduced nest-sitting), physiological (flight feather asymmetry) and reproductive (chicks fledged/territorial pair) effects and reduced survival.[360] Additionally, Evers, *et al.,* (*see* footnote 5), believe that the weight of evidence indicates that population-level effects occur in parts of Maine and New Hampshire, and potentially in broad areas of the loon's range.

Recently, attention has turned to other piscivorous species such as the white ibis and great snowy egret. These wading birds have a very wide diet including crayfish, crabs, snails, insects and frogs. White ibis have been observed to have decreased foraging efficiency[361] and have been shown to exhibit decreased reproductive success and altered pair behavior.[362] In egrets, Hg has been implicated in the decline of the species in south Florida,[363] and Hoffman[364] has shown that egrets exhibit liver and possibly kidney effects. Although ibises and egrets are most abundant in coastal areas and these studies were conducted in south Florida and Nevada, the ranges of ibises and egrets extend to a large portion of the U.S.

Insectivorous birds have also been shown to suffer adverse effects due to Hg exposure. Songbirds such as Bicknell's thrush, tree swallows, and the great tit have shown reduced reproduction, survival, and changes in singing behavior. Exposed tree swallows produced fewer fledglings,[365] had lower survival rates,[366] and had compromised immune competence.[367] The great tit has exhibited reduced singing behavior and smaller song repertoire in areas of high contamination.[368]

In mammals, adverse effects have been observed in mink and river otter, both fish eating species. For otter from Maine and Vermont, maximum concentrations of Hg in fur nearly equal or exceed a level associated with mortality and concentration in liver for mink in Massachusetts/Connecticut and the levels in fur from mink in Maine exceed concentrations associated with acute mortality.[369] Adverse sublethal effects may be associated with lower Hg concentrations and consequently may be more widespread than potential acute effects. These effects may include increased activity, poorer maze performance, abnormal startle reflex, and impaired escape and avoidance behavior.[370]

h. Methodology for Partial Hg Benefits Estimation. The EPA has conducted a national-scale analysis of the benefits to recreational anglers of avoided IQ loss related to reductions of Hg emissions

[358] Crump, KL, and Trudeau, VL. Mercury-induced reproductive impairment in fish. Environmental Toxicology and Chemistry. Vol. 28, No. 5, 2009.

[359] U.S. Environmental Protection Agency (EPA). 1997. Mercury Study Report to Congress. Volume V: Health Effects of Mercury and Mercury Compounds. EPA–452/R–97–007. U.S. EPA Office of Air Quality Planning and Standards, and Office of Research and Development; U.S. Environmental Protection Agency (U.S. EPA). 2005. *Regulatory Impact Analysis of the Final Clean Air Mercury Rule.* Research Triangle Park, NC., March; EPA report no. EPA–452/R–05–003. Available on the Internet at *http://www.epa.gov/ttn/ecas/regdata/RIAs/mercury_ria_final.pdf.*

[360] Evers, DC, Savoy, LJ, DeSorbo, CR, Yates, DE, Hanson, W, Taylor, KM, Siegel, LS, Cooley, JH, Jr., Bank, MS, Major, A, Munney, K, Mower, BF, Vogel, HS, Schoch, N, Pokras, M, Goodale, MW, Fair, J. Adverse effects from environmental mercury loads on breeding common loons. Ecotoxicology. 17:69–81, 2008; Mitro, MG, Evers, DC, Meyer, MW, and Piper, WH. Common loon survival rates and mercury in New England and Wisconsin. Journal of Wildlife Management. 72(3): 665–673, 2008.

[361] Adams, EM, and Frederick, PC. Effects of methylmercury and spatial complexity on foraging behavior and foraging efficiency in juvenile white ibises (Eudocimus albus). Environmental Toxicology and Chemistry. Vol 27, No. 8, 2008.

[362] Frederick, P, and Jayasena, N. Altered pairing behavior and reproductive success in white ibises exposed to environmentally relevant concentrations of methylmercury. Proceedings of The Royal Society B. doi: 10–1098, 2010.

[363] Sepulveda, MS, Frederick, PC, Spalding, MG, and Williams, GE, Jr. Mercury contamination in free-ranging great egret nestlings (Ardea albus) from southern Florida, USA. Environmental Toxicology and Chemistry. Vol. 18, No. 5, 1999.

[364] Hoffman, DJ, Henny, CJ, Hill, EF, Grover, RA, Kaiser, JL, Stebbins, KR. Mercury and drought along the lower Carson River, Nevada: III. Effects on blood and organ biochemistry and histopathology of snowy egrets and black-crowned night-herons on Lahontan Reservoir, 2002–2006. Journal of Toxicology and Environmental Health, Part A. 72: 20, 1223–1241, 2009.

[365] Brasso, RL, and Cristol, DA. Effects of mercury exposure in the reproductive success of tree swallows (Tachycineta bicolor). Ecotoxicology. 17:133–141, 2008.

[366] Hallinger, KK, Cornell, KL, Brasso, RL, and Cristol, DA. Mercury exposure and survival in free-living tree swallows (Tachycineta bicolor). Ecotoxicology. Doi: 10.1007/s10646–010–0554–4, 2010.

[367] Hawley, DM, Hallinger, KK, Cristol, DA. Compromised immune competence in free-living tree swallows exposed to mercury. Ecotoxicology. 18:499–503, 2009.

[368] Gorissen, L, Snoeijs, T, Van Duyse, E, and Eens, M. Heavy metal pollution affects dawn singing behavior in a small passerine bird. Oecologia. 145: 540–509, 2005.

[369] Yates, DE, Mayack, DT, Munney, K, Evers DC, Major, A, Kaur, T, and Taylor, RJ. Mercury levels in mink (Mustela vison) and river otter (Lonra canadensis) from northeastern North America. Ecotoxicology. 14, 263–274, 2005.

[370] Scheuhammer, AM, Meyer MW, Sandheinrich, MB, and Murray, MW. Effects of environmental methylmercury on the health of wild birds, mammals, and fish. Ambio. Vol.36, No.1, 2007.

and subsequent deposition that will be achieved by this rule. Because the primary measurable health effect of concern—developmental neurological abnormalities in children—occurs as a result of in-utero exposures to Hg, the specific population of interest in this case is prenatally exposed children. To identify and estimate the size of this exposed population, the benefits analysis focused on pregnant women in freshwater recreational angler households. Estimating Hg exposures for this exposure pathway and population of interest requires three main components: (1) The size of the exposed population of interest (annual number of pregnant women in freshwater angler households during the year), (2) the average concentration of MeHg in noncommercial freshwater fish filets consumed, and (3) the average daily consumption rate of noncommercial freshwater fish. The Hg concentrations of fish in the waterbodies where the fish are caught are modeled using Mercury Maps to project the decline in concentrations due to the rule. To approximate the percentage of freshwater fishing trips (and exposed individuals) from each Census tract matched to each waterbody type, the EPA used state-level averages. These averages were calculated for each state, based on the portion of residents' freshwater fishing trips that are to each waterbody type, based on 2001 National Survey of Fishing, Hunting, and Wildlife-Associated Recreation (FHWAR) data.

Data from the 1994 National Survey on Recreation and the Environment (NSRE) were used to approximate the percentage of freshwater fishing trips (and exposed individuals) matched to different distances from anglers' residential location.

To determine an appropriate daily fish consumption rate for the analysis, the EPA conducted an extensive review of existing literature characterizing self-caught freshwater fish consumption. Based on this review, it was decided that the ingestion rates for recreational freshwater fishers, specified as "recommended" in the EPA's "Environmental Exposure Factors Handbook" (EPA, 1997), represented the most appropriate values to use in this analysis.

Estimating the IQ decrements in children that result from mothers' prenatal ingestion of Hg from fish required two steps. First, based on the estimated average daily maternal ingestion rate, the expected Hg concentration in the hair of exposed pregnant women was estimated. Second, to estimate the expected IQ decrement in offspring, the following dose-response relationship was developed based on the summary findings reported in Axelrad *et al.*, (2007).

The valuation approach used to assess monetary losses due to IQ decrements is based on an approach applied in previous EPA analyses (EPA, 2008). The approach expresses the potential loss to an affected individual resulting from IQ decrements in terms of foregone future earnings (net of changes in education costs) for that individual.

The estimate for "Present Value of Lifetime Earnings" is derived using earnings and labor force participation rate data from the Bureau of Labor Statistics 2006 Current Population Survey. Estimates of the average effect of a 1-point increase in IQ on lifetime earnings range from a 1.76 percent increase (Schwartz, 1994) to a 2.379 percent increase (Salkever, 1995). The percentage increases in the two studies reflect both the direct impact of IQ on hourly wages and indirect effects on annual earnings as the result of additional schooling and increased labor force participation. The estimate for years of additional schooling is based on Schwartz (1994), who reports an increase of 0.131 years of schooling per IQ point.

In addition to this positive net effect on earnings, an increase in IQ is also assumed to have a positive effect on the amount of time spent in school and on associated costs. To incorporate (1) uncertainty regarding the size of the percentage change in future earnings and (2) different assumptions regarding the discount rate, the resulting value estimates for the average net loss per IQ point decrement are expressed as a range. Assuming a 3 percent discount rate, value IQ ranges from $8,013 (using the Schwartz estimates) to $11,859 (using the Salkever estimates) in increased earnings per year per 1-point IQ increase. With a 7 percent discount rate assumption, the value IQ estimates range from $893 to $1,958 in increased earnings per year per 1-point IQ increase.

The EPA analyzed the aggregate national IQ and present-value loss estimates for two base case and three emission control scenarios. The highest losses are estimated for the 2005 base case. For the population of prenatally exposed children included in the analysis (almost 240,000), Hg exposures under baseline conditions during the year 2005 are estimated to have resulted in more than 25,500 IQ points lost. Assuming a 3 percent discount rate, the present-year value of these losses ranges from $204.8 million to $292.5 million nationally.[371] These losses represent expected present value of declines in future net earnings over the entire lifetimes of the children who are prenatally exposed during the year 2005. With a 7 percent discount rate, the present-year value range is considerably lower: $22.8 million to $50.0 million.

For this rule, the EPA generated estimates of aggregate nationwide benefits associated with reductions in Hg exposures and resulting reductions in IQ losses. Most importantly, the benefits of the 2016 MATS scenario (relative to the 2016 base case) are estimated to range between $4 million and $6 million (assuming a 3 percent discount rate), because of an estimated 511 point reduction in IQ losses. The EPA recognizes that these calculated benefits are a small subset of the benefits of reducing Hg emissions.

2. Health and Welfare Co-Benefits

Emission controls installed to meet the requirements of this rule will generate co-benefits by reducing criteria pollutants including $PM_{2.5}$ and SO_2, as well as CO_2. For this rule, we were only able to estimate the mortality benefits of $PM_{2.5}$ reductions due to changes in emissions of SO_2 and direct $PM_{2.5}$ and climate benefits resulting from CO_2 reductions. Additional co-benefits may result from decreases in $PM_{2.5}$ morbidity impacts, decreases in sulfur deposition and direct health effects of SO_2, and improvements in visibility in national parks and wilderness areas. Total co-benefits may be higher than the partial estimates of co-benefits provided here. Our best estimate of the monetized health and climate co-benefits of this rule in 2016 at a 3 percent discount rate are $37 billion to $90 billion or $33 billion to $81 billion at a 7 percent discount rate (2007$). Using alternate relationships between $PM_{2.5}$ and premature mortality supplied by experts, higher and lower health co-benefits estimates are plausible, but most of the expert-based estimates fall between these two estimates.[372]

a. Human Health Co-Benefits. To estimate the human health co-benefits of this rule, the EPA used benefit-per-ton

[371] Monetized benefits estimates are for an immediate change in MeHg levels in fish. If a lag in the response of MeHg levels in fish were assumed, the monetized benefits could be significantly lower, depending on the length of the lag and the discount rate used. As noted in the discussion of the Mercury Maps modeling, the relationship between deposition and fish tissue MeHg is proportional in equilibrium, but the Mercury Maps approach does not provide any information on the time lag of response.

[372] Roman, *et al.*, 2008. Expert Judgment Assessment of the Mortality Impact of Changes in Ambient Fine Particulate Matter in the U.S. Environ. Sci. Technol., 42, 7, 2268–2274.

factors to quantify the changes in $PM_{2.5}$-related health impacts and monetized benefits based on changes in SO_2 and direct $PM_{2.5}$ emissions. These benefit-per-ton factors were based on an interim baseline and policy scenario for which full-scale ambient air quality modeling and air quality-based human health benefits assessments were performed. This general approach and methodology is laid out in Fann, *et al.*, (2009),[373] but for this rule the air quality modeling used a better spatial representation of the emission changes from EGUs. Using a benefit-per-ton approach adds another important source of uncertainty to the benefits estimates. For more details on the creation of the benefit-per-ton factors and their application to emission reductions under this rule, please refer to the RIA for this rule in the docket.

Table 9 presents the estimates of reduced annual incidence of $PM_{2.5}$-related health effects in 2016 resulting from this rule. Table 10 presents the estimated annual monetary value of the reduced incidence of quantified health endpoints in 2016 resulting from this rule.

The reduction in premature fatalities each year accounts for between 93 and 97 percent of the estimated health co-benefits that were monetized.

TABLE 9—ESTIMATED REDUCTIONS IN INCIDENCE OF $PM_{2.5}$-RELATED HEALTH EFFECTS IN 2016 [a]

Health effect	Number of reduced cases
Adult Premature Mortality	
Pope *et al.*, (2002) (age >30)	4,200.
	(1,200 to 7,200).
Laden *et al.*, (2006) (age >25)	11,000.
	(5,000 to 17,000).
Infant Premature Mortality (<1 year)	20.
	(−22 to 61).
Chronic Bronchitis	2,800.
	(88 to 5,600).
Non-fatal heart attacks (age >18)	4,700.
	(1,200 to 8,300).
Hospital admissions—respiratory (all ages)	830.
	(330 to 1,300).
Hospital admissions—cardiovascular (age >18)	1,800.
	(1,200 to 2,200).
Emergency room visits for asthma (age <18)	3,100.
	(1,600 to 4,700).
Acute bronchitis (age 8–12)	6,300.
	(−1,400 to 14,000).
Lower respiratory symptoms (age 7–14)	80,000.
	(31,000 to 130,000).
Upper respiratory symptoms (asthmatics age 9–11)	60,000.
	(11,000 to 110,000).
Asthma exacerbation (asthmatics 6–18)	130,000.
	(4,500 to 450,000).
Lost work days (ages 18–65)	540,000.
	(460,000 to 620,000).
Minor restricted-activity days (ages 18–65)	3,200,000.
	(2,600,000 to 3,800,000).

[a] Values rounded to two significant figures. Co-benefits from reducing exposure to ozone, other criteria pollutants, and HAP, as well as reducing visibility impairment and ecosystem effects are not included here.

TABLE 10—ESTIMATED MONETARY VALUE (BILLIONS 2007$) OF $PM_{2.5}$-RELATED HEALTH BENEFITS IN 2016 [a]

Health effect	Monetized benefits
Adult Premature Mortality	
Pope, *et al.*, (2002) (age >30):	
3% discount rate	$34.
	($2.6 to $100).
7% discount rate	$30.
	($2.4 to $92).
Laden, *et al.*, (2006) (age >25):	
3% discount rate	$87.
	($7.5 to $250).
7% discount rate	$78.
	($6.8 to $230).
Infant Premature Mortality (<1 year)	$0.2.
	($−0.2 to $0.8).
Chronic Bronchitis	$1.4.
	($0.1 to $6.4).
Non-fatal heart attacks (age >18):	

[373] Fann, N., C.M. Fulcher, B.J. Hubbell. 2009. "The influence of location, source, and emission type in estimates of the human health benefits of reducing a ton of air pollution." Air Qual Atmos Health (2009) 2:169–176.

TABLE 10—ESTIMATED MONETARY VALUE (BILLIONS 2007$) OF $PM_{2.5}$-RELATED HEALTH BENEFITS IN 2016 [a]—Continued

Health effect	Monetized benefits
3% discount rate	$0.5. ($0.1 to $1.3).
7% discount rate	$0.4. ($0.1 to $1.0).
Hospital admissions—respiratory (all ages)	$0.01. ($0.01 to $0.02).
Hospital admissions—cardiovascular (age >18)	$0.03. (<$0.01 to $0.05).
Emergency room visits for asthma (age <18)	<$0.01.
Acute bronchitis (age 8–12)	<$0.01.
Lower respiratory symptoms (age 7–14)	<$0.01.
Upper respiratory symptoms (asthmatics age 9–11)	<$0.01.
Asthma exacerbation (asthmatics 6–18)	<$0.01.
Lost work days (ages 18–65)	$0.1. ($0.1 to $0.1).
Minor restricted-activity days (ages 18–65)	$0.2. ($0.1 to $0.3).
Monetized Health Co-Benefits	
Pope, *et al.*, (2002):	
3% discount rate	$36. ($2.8–$110).
7% discount rate	$33. ($2.5–$100).
Laden, *et al.*, (2006):	
3% discount rate	$89. ($7.7–$260).
7% discount rate	$80. ($6.9–$240).

[a] Values rounded to two significant figures. Co-benefits from reducing exposure to ozone, other criteria pollutants, and HAP, as well as reducing visibility impairment and ecosystem effects are not included here.

It is important to note that the magnitude of the $PM_{2.5}$ co-benefits is largely driven by the concentration response function for premature mortality. Experts have advised the EPA to consider a variety of assumptions, including estimates based both on empirical (epidemiological) studies and judgments elicited from scientific experts, to characterize the uncertainty in the relationship between $PM_{2.5}$ concentrations and premature mortality. We cite two key empirical studies, one based on the American Cancer Society cohort study [374] and the other based on the extended Six Cities cohort study.[375] The analyses upon which this rule is based were selected from the peer-reviewed scientific literature. We used up-to-date assessment tools, and we believe the results are highly useful in assessing this rule.

Every benefit analysis examining the potential effects of a change in environmental protection requirements is limited to some extent by data gaps, model capabilities (such as geographic coverage), and uncertainties in the underlying scientific and economic studies used to configure the benefit and cost models. Gaps in the scientific literature often result in the inability to estimate quantitative changes in health and environmental effects, or to assign economic values even to those health and environmental outcomes that can be quantified. The uncertainties in the underlying scientific and economics literature (that may result in overestimation or underestimation of the co-benefits) are discussed in detail in the RIA. Despite these uncertainties, we believe the benefit analysis for this rule provides a reasonable indication of the expected health co-benefits of the rulemaking in future years under a set of reasonable assumptions.

When characterizing uncertainty in the PM-mortality relationship, the EPA has historically presented a sensitivity analysis applying alternate assumed thresholds in the PM concentration-response relationship. In its synthesis of the current state of the PM science, the EPA's 2009 Integrated Science Assessment for Particulate Matter concluded that a no-threshold log-linear model most adequately portrays the PM-mortality concentration-response relationship.

In the RIA accompanying this rulemaking, rather than segmenting out impacts predicted to be associated with levels above and below a "bright line" threshold, the EPA includes a "lowest measured level" (LML) analysis that illustrates the increasing uncertainty that characterizes exposure attributed to levels of $PM_{2.5}$ below the LML of each epidemiological study used to estimate $PM_{2.5}$-related premature death. Figures provided in the RIA show the distribution of baseline exposure to $PM_{2.5}$, as well as the lowest air quality levels measured in each of the epidemiology cohort studies. This information provides a context for considering the likely portion of PM-related mortality benefits occurring above or below the LML of each study; in general, our confidence in the size of the estimated reduction in $PM_{2.5}$-related premature mortality diminishes as baseline concentrations of $PM_{2.5}$ are lowered.

Based on the modeled interim baseline which is approximately equivalent to the final baseline (*see* Appendix A of the RIA), 11 percent and 73 percent of the estimated avoided mortality impacts occur at or above an

[374] Pope *et al.*, 2002. "Lung Cancer, Cardiopulmonary Mortality, and Long-term Exposure to Fine Particulate Air Pollution." Journal of the American Medical Association. 287:1132–1141.

[375] Laden*et al.*, 2006. "Reduction in Fine Particulate Air Pollution and Mortality." American Journal of Respiratory and Critical Care Medicine. 173:667–672.

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annual mean $PM_{2.5}$ level of 10 μg/m3 (the LML of the Laden*et al.,* 2006 study)or 7.5 μg/m3 (the LML of the Pope,*et al.,* 2002 study), respectively. Although the LML analysis provides some insight into the level of uncertainty in the estimated PM mortality benefits, the EPA does not view the LML as a threshold and continues to quantify PM-related mortality impacts using a full range of modeled air quality concentrations. A large fraction of the $PM_{2.5}$-related benefits occur below the level of the National Ambient Air Quality Standard (NAAQS) for $PM_{2.5}$ at 15 μg/m3, which was set in 2006. It is important to emphasize that NAAQS are not set at a level of zero risk. Instead, the NAAQS reflect the level determined by the Administrator to be protective of public health within an adequate margin of safety, taking into consideration effects on susceptible populations. While benefits occurring below the standard may be less certain than those occurring above the standard, EPA considers them to be legitimate components of the total benefits estimate.

It is important to note that the monetized benefits include many but not all health effects associated with $PM_{2.5}$ exposure. Benefits are shown as a range from Pope, *et al.,* (2002), to Laden, *et al.,* (2006). These studies assume that all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality because there is no clear scientific evidence that would support the development of differential effects estimates by particle type. Even though we assume that all fine particles have equivalent health effects, the benefit-per-ton estimates vary between directly-emitted particles (carbonaceous and crustal particles) and SO_2 emissions that form sulfate particles, based on the location of emission changes and magnitude of population exposure changes. Regardless, however, the assumption that all fine particles are equally potent in causing premature mortality adds uncertainty to the benefits estimate.

b. Non-Climate Welfare Co-Benefits. Emission controls installed to comply with the requirements specified in this rule will also generate co-benefits by improving visibility. We anticipate that improvements in visibility in Class I areas as well as residential areas where people live, work, and recreate could be substantial. Because full-scale air quality modeling was not performed for this rule, we are unable to quantify these visibility co-benefits for this rule. However, the estimated value of visibility benefits calculated from the modeled interim baseline and policy scenario was $1.1 billion (in 2007$). These visibility benefits are not included in the total co-benefits estimate of the final policy scenario used as a basis for this final rule. The distribution of emission reductions did not change substantially in the visibility regions studied, therefore visibility benefits of the final policy scenario are likely to be of a similar magnitude.

Ecosystem and other welfare effects include reduced acidification and, in the case of NO_X, eutrophication of water bodies; possible reduced nitrate contamination of drinking water; ozone vegetation damage; a reduction in the role of sulfate in Hg methylation; and reduced acid and particulate deposition that causes damages to cultural monuments, as well as soiling and other materials damage. To illustrate the important nature of benefit categories the EPA is currently unable to monetize, we discuss the potential public welfare and environmental impacts related to reductions in emissions required by this rule in the RIA, including reduced visibility impairment, reduced effects from acid deposition, reduced effects from nutrient enrichment, and reduced vegetation effects from ambient exposure to SO_2 and NO_2.

c. Climate co-benefits. This rule is expected to reduce CO_2 emissions from the electricity sector. The EPA has assigned a dollar value to reductions in CO_2 emissions using recent estimates of the "social cost of carbon" (SCC). The SCC is an estimate of the monetized damages associated with an incremental increase in carbon emissions in a given year or the per metric ton benefit estimate relating to decreases in CO_2 emissions. It is intended to include (but is not limited to) changes in net agricultural productivity, human health, property damage from increased flood risk, and the value of ecosystem services due to climate change.

The SCC estimates used in this analysis were developed through an interagency process that included the EPA and other executive branch entities, and that concluded in February 2010. We first used these SCC estimates in the benefits analysis for the final joint EPA/DOT Rulemaking to establish Light-Duty Vehicle Greenhouse Gas Emission Standards and Corporate Average Fuel Economy Standards; see the rule's preamble for discussion about application of the SCC (75 FR 25324; May 7, 2010). The SCC Technical Support Document (SCC TSD) provides a complete discussion of the methods used to develop these SCC estimates.[376]

The interagency group selected four SCC values for use in regulatory analyses, which we have applied in this analysis: $5.9, $24.3, $39, and $74.4 per metric ton of CO_2 emissions in 2016, in 2007 dollars. The first three values are based on the average SCC from three integrated assessment models, at discount rates of 5, 3, and 2.5 percent, respectively. Social cost of carbon values at several discount rates are included because the literature shows that the SCC is quite sensitive to assumptions about the discount rate, and because no consensus exists on the appropriate rate to use in an intergenerational context. The fourth value is the 95th percentile of the SCC from all three values at a 3 percent discount rate. It is included to represent higher-than-expected impacts from temperature change further out in the extremes of the SCC distribution. Low probability, high impact events are incorporated into all of the SCC values through explicit consideration of their effects in two of the three values as well as the use of a probability density function for equilibrium climate sensitivity. Treating climate sensitivity probabilistically results in more high temperature outcomes, which in turn leads to higher projections of damages.

Applying the global SCC estimates using a 3 percent discount rate, we estimate the value of the climate related benefits of this rule in 2016 is $360 million (2007$), as shown in Table 11. See the RIA for more detail on the methodology used to calculate these benefits and additional estimates of climate benefits using different discount rates and the 95th percentile of the 3 percent discount rate SCC. Important limitations and uncertainties of the SCC approach are also described in the RIA.

[376] Docket ID EPA–HQ–OAR–2009–0472–114577, Technical Support Document: Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866, Interagency Working Group on Social Cost of Carbon, with participation by Council of Economic Advisers, Council on Environmental Quality, Department of Agriculture, Department of Commerce, Department of Energy, Department of Transportation, Environmental Protection Agency, National Economic Council, Office of Energy and Climate Change, Office of Management and Budget, Office of Science and Technology Policy, and Department of Treasury (February 2010). Also available at *http://epa.gov/otaq/climate/regulations.htm.*

TABLE 11—ESTIMATED MONETARY VALUE (BILLIONS 2007$) OF $PM_{2.5}$-RELATED HEALTH BENEFITS AND CLIMATE BENEFITS IN 2016[a]

Effect	Monetized benefits
Monetized Health Co-Benefits	
Pope, *et al.*, (2002):	
3% discount rate	$36 ($2.8–$110)
7% discount rate	$33 ($2.5–$100)
Laden, *et al.*, (2006):	
3% discount rate	$89 ($7.7–$260)
7% discount rate	$80 ($6.9–$240)
Climate-related Co-Benefits (3% discount rate)	$0.36
Monetized Total Co-Benefits	
Pope, *et al.*, (2002):	
3% discount rate	$37 ($3.2–$110)
7% discount rate	$33 ($2.9–$100)
Laden, *et al.*, (2006):	
3% discount rate	$90 ($8.0–$260)
7% discount rate	$81 ($7.3–$240)

[a] Values rounded to two significant figures. Co-benefits from reducing exposure to ozone, other criteria pollutants, and HAP, as well as reducing visibility impairment and ecosystem effects are not included here.

Our best estimate for the monetized total health and climate co-benefits of this rule in 2016 at a 3 percent discount rate is between $37 billion and $90 billion or between $33 billion and $81 billion (2007$) at a 7 percent discount rate. These estimates account for the quantified health and climate benefits described in Table 11.

XIII. Statutory and Executive Order Reviews

A. Executive Order 12866, Regulatory Planning and Review and Executive Order 13563, Improving Regulation and Regulatory Review

Under EO 12866 (58 FR 51735; October 4, 1993), this action is an "economically significant regulatory action" because it is likely to have an annual effect on the economy of $100 million or more or adversely affect in a material way the economy, a sector of the economy, productivity, competition, jobs, the environment, public health or safety, or state, local, or tribal governments or communities. Accordingly, the EPA submitted this action to the OMB for review under Executive Orders 12866 and 13563 and any changes in response to OMB recommendations have been documented in the docket for this action. For more information on the costs and benefits for this rule, please refer to Table 2 of this preamble.

When estimating the human health benefits and compliance costs in Table 2 of this preamble, the EPA applied methods and assumptions consistent with the state-of-the-science for human health impact assessment, economics and air quality analysis. The EPA applied its best professional judgment in performing this analysis and believes that these estimates provide a reasonable indication of the expected benefits and costs to the nation of this rulemaking. The RIA available in the docket describes in detail the empirical basis for the EPA's assumptions and characterizes the various sources of uncertainties affecting the estimates below. In doing what is laid out above in this paragraph, the EPA adheres to EO 13563, "Improving Regulation and Regulatory Review," (76 FR 3821; January 18, 2011), which is a supplement to EO 12866.

In addition to estimating costs and benefits, EO 13563 focuses on the importance of a "regulatory system [that] * * * promote[s] predictability and reduce[s] uncertainty" and that "identify[ies] and use[s] the best, most innovative, and least burdensome tools for achieving regulatory ends." In addition, EO 13563 states that "[i]n developing regulatory actions and identifying appropriate approaches, each agency shall attempt to promote such coordination, simplification, and harmonization. Each agency shall also seek to identify, as appropriate, means to achieve regulatory goals that are designed to promote innovation." We recognize that the utility sector faces a variety of requirements, including ones under CAA section 110(a)(2)(D) dealing with the interstate transport of emissions contributing to ozone and PM air quality problems, with coal combustion wastes, and with the implementation of CWA section 316(b). In developing today's final rule, the EPA recognizes that it needs to approach these rulemakings in ways that allow the industry to make practical investment decisions that minimize costs in complying with all of the final rules, while still achieving the fundamentally important environmental and public health benefits that underlie the rulemakings.

A summary of the monetized costs, benefits, and net benefits for the final rule at discount rates of 3 percent and 7 percent is in Table 2 of this preamble. For more information on the analysis, please refer to the RIA for this rulemaking, which is available in the docket.

B. Paperwork Reduction Act

The information collection requirements in this rule have been submitted for approval to the OMB under the Paperwork Reduction Act, 44

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U.S.C. 3501 et seq. The Information Collection Request (ICR) document prepared by the EPA has been assigned EPA ICR number 2137.06.

The information collection requirements are not enforceable until OMB approves them. The information requirements are based on notification, recordkeeping, and reporting requirements in the NESHAP General Provisions (40 CFR part 63, subpart A), which are mandatory for all operators subject to national emission standards. These recordkeeping and reporting requirements are specifically authorized by CAA section 114 (42 U.S.C. 7414). All information submitted to the EPA pursuant to the recordkeeping and reporting requirements for which a claim of confidentiality is made is safeguarded according to Agency policies set forth in 40 CFR part 2, subpart B. This final rule requires maintenance inspections of the control devices but would not require any notifications or reports beyond those required by the General Provisions. The recordkeeping requirements require only the specific information needed to determine compliance.

When a malfunction occurs, sources must report them according to the applicable reporting requirements of 40 CFR part 63, subpart UUUUU. An affirmative defense to civil penalties for exceedances of emission limits that are caused by malfunctions is available to a source if it can demonstrate that certain criteria and requirements are satisfied. The criteria ensure that the affirmative defense is available only where the event that causes an exceedance of the emission limit meets the narrow definition of malfunction in 40 CFR 63.2 (sudden, infrequent, not reasonable preventable, and not caused by poor maintenance and or careless operation) and where the source took necessary actions to minimize emissions. In addition, the source must meet certain notification and reporting requirements. For example, the source must prepare a written root cause analysis and submit a written report to the Administrator documenting that it has met the conditions and requirements for assertion of the affirmative defense.

For this rule, EPA is adding affirmative defense to the estimate of burden in the ICR. To provide the public with an estimate of the relative magnitude of the burden associated with an assertion of the affirmative defense position adopted by a source, the EPA has provided administrative adjustments to this ICR that shows what the notification, recordkeeping, and reporting requirements associated with the assertion of the affirmative defense might entail. The EPA's estimate for the required notification, reports, and records, including the root cause analysis, associated with a single incident totals approximately totals $3,141, and is based on the time and effort required of a source to review relevant data, interview plant employees, and document the events surrounding a malfunction that has caused an exceedance of an emission limit. The estimate also includes time to produce and retain the record and reports for submission to EPA. The EPA provides this illustrative estimate of this burden, because these costs are only incurred if there has been a violation, and a source chooses to take advantage of the affirmative defense.

The EPA provides this illustrative estimate of this burden because these costs are only incurred if there has been a violation and a source chooses to take advantage of the affirmative defense. Given the variety of circumstances under which malfunctions could occur, as well as differences among sources' operation and maintenance practices, we cannot reliably predict the severity and frequency of malfunction-related excess emissions events for a particular source. It is important to note that the EPA has no basis currently for estimating the number of malfunctions that would qualify for an affirmative defense. Current historical records would be an inappropriate basis, as source owners or operators previously operated their facilities in recognition that they were exempt from the requirement to comply with emissions standards during malfunctions. Of the number of excess emissions events reported by source operators, only a small number would be expected to result from a malfunction (based on the definition above), and only a subset of excess emissions caused by malfunctions would result in the source choosing to assert the affirmative defense. Thus, we believe the number of instances in which source operators might be expected to avail themselves of the affirmative defense will be extremely small.

For this reason, we estimate no more than two such occurrences for all sources subject to 40 CFR part 63, subpart UUUUU over the 3-year period covered by this ICR. We expect to gather information on such events in the future, and will revise this estimate as better information becomes available.

The annual monitoring, reporting, and record-keeping burden for this collection (averaged over the first 3 years after the effective date of the standards) is estimated to be $207.6 million. This includes 700,296 labor hours per year at a total labor cost of $49.1 million per year, annualized capital costs of $81.9 million, and annual operating and maintenance costs of $76.5 million. This estimate includes initial and annual performance tests, semiannual excess emission reports, developing a monitoring plan, notifications, and recordkeeping. All burden estimates are in 2007 dollars and represent the most cost effective monitoring approach for affected facilities. Burden is defined at 5 CFR 1320.3(b).

An Agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for our regulations are listed in 40 CFR part 9. When this ICR is approved by OMB, the Agency will publish a technical amendment to 40 CFR part 9 in the **Federal Register** to display the OMB control number for the approved information collection requirements contained in this final rule.

C. Regulatory Flexibility Act, as Amended by the Small Business Regulatory Enforcement Fairness Act of 1996 (SBREFA), 5 U.S.C. 601 et seq.

The Regulatory Flexibility Act (RFA) generally requires an agency to prepare a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements under the Administrative Procedure Act or any other statute unless the agency certifies that the rule will not have a significant economic impact on a substantial number of small entities. Small entities include small businesses, small organizations, and small governmental jurisdictions.

For purposes of assessing the impacts of today's rule on small entities, small entity is defined as: (1) A small business that is an electric utility producing 4 billion kilowatt-hours or less as defined by NAICS codes 221122 (fossil fuel-fired electric utility steam generating units) and 921150 (fossil fuel-fired electric utility steam generating units in Indian country); (2) a small governmental jurisdiction that is a government of a city, county, town, school district or special district with a population of less than 50,000; and (3) a small organization that is any not-for-profit enterprise which is independently owned and operated and is not dominant in its field.

Pursuant to RFA section 603, the EPA prepared an initial regulatory flexibility analysis (IRFA) for the proposed rule and convened a Small Business Advocacy Review Panel to obtain advice

and recommendations of representatives of the regulated small entities. A detailed discussion of the Panel's advice and recommendations is found in the Panel Report (EPA–HQ–OAR–2009–0234–2921). A summary of the Panel's recommendations is presented at 76 FR 24975.

As required by RFA section 604, we also prepared a final regulatory flexibility analysis (FRFA) for the final rule. The FRFA addresses the issues raised by public comments on the IRFA, which was part of the proposal of this rule. The FRFA is summarized below and in the RIA.

1. Reasons Why Action Is Being Taken

In 2000, the EPA made a finding that it was appropriate and necessary to regulate coal- and oil-fired EGUs under CAA section 112 and listed EGUs pursuant to CAA section 112(c). On March 29, 2005 (70 FR 15994), the EPA published a final rule (2005 Action) that removed EGUs from the list of sources for which regulation under CAA section 112 was required. That rule was published in conjunction with a rule requiring reductions in emissions of Hg from EGUs pursuant to CAA section 111, i.e., CAMR, May 18, 2005, 70 FR 28606). The 2005 Action was vacated on February 8, 2008, by the U.S. Court of Appeals for the District of Columbia Circuit. As a result of that vacatur, CAMR was also vacated and EGUs remain on the list of sources that must be regulated under CAA section 112. This action provides the EPA's final NESHAP and NSPS for EGUs.

2. Statement of Objectives and Legal Basis for Final Rules

The MATS will protect air quality and promote public health by reducing emissions of HAP. In the December 2000 regulatory determination, the EPA made a finding that it was appropriate and necessary to regulate EGUs under CAA section 112. The February 2008 vacatur of the 2005 Action reverted the status of the rule to the December 2000 regulatory determination. Section 112(n)(1)(A) of the CAA and the 2000 determination do not differentiate between EGUs located at major versus area sources of HAP. Thus, the NESHAP for EGUs will regulate units at both major and area sources. Major sources of HAP are those that have the potential to emit at least 10 tons per year (tpy) of any one HAP or at least 25 tpy of any combination of HAP. Area sources are any stationary sources of HAP that are not major sources.

3. Summary of Issues Raised During the Public Comment Process on the IRFA

The EPA received a number of comments related to the Regulatory Flexibility Act during the public comment process. A consolidated version of the comments received is reproduced below. These comments can also be found in their entirety in the response to comment document in the docket.

Comment: Several commenters expressed concern with the SBAR panel. Some believe Small Entity Representatives (SERs) were not provided with regulatory alternatives including descriptions of significant regulatory options, differing timetables, or simplifications of compliance and reporting requirements, and subsequently were not presented with an opportunity to respond. One commenter believes the EPA's formal SBAR Panel notification and subsequent information provided by the EPA to the Panel did not include information on the potential impacts of the rule as required by CAA section 609(b)(1). Additional commenters suggested that the EPA's rulemaking schedule put pressure on the SBAR Panel through the abbreviated preparation for the Panel. Commenters also expressed concerns that the EPA did not provide participants more than cursory background information on which to base their comments. One commenter stated that the EPA did not provide deliberative materials, including draft proposed rules or discussions of regulatory alternatives, to the SBAR Panel members. One commenter stated the SBAR Panel Report does not meet the statutory obligation to recommend less burdensome alternatives. The commenter suggested the EPA panel members declined to make recommendations that went further than consideration or investigation of broad regulatory alternatives, with the exception of those recommendations in which the EPA rejected alternative interpretations of the CAA section 112 and relevant court cases. Two stated that the EPA did not respond to the concerns of the small business community, the SBA, or OMB, ignoring concerns expressed by the SER panelists. One commenter believes the EPA failed to convene required meetings and hearings with affected parties as required by law for small business entities. One commenter stated that the SERs' input is very important because more than 90 percent of public power utility systems meet the definition and qualify as small businesses under the SBREFA.

Response: The RFA requires that SBAR Panels collect advice and recommendations from SERs on the issues related to:

—The number and description of the small entities to which the proposed rule will apply;
—The projected reporting, recordkeeping and other compliance requirements of the proposed rule;
—Duplication, overlap or conflict between the proposed rule and other federal rules; and
—Alternatives to the proposed rule that accomplish the stated statutory objectives and minimize any significant economic impact on small entities.

The RFA does not require a covered agency to create or assemble information for SERs or for the government panel members. Although CAA section 609(b)(4) requires that the government Panel members review any material the covered agency has prepared in connection with the RFA, the law does not prescribe the materials to be reviewed. The EPA's policy, as reflected in its RFA guidance, is to provide as much information as possible, given time and resource constraints, to enable an informed Panel discussion. In this rulemaking, because of a court-ordered deadline, the EPA was unable to hold a pre-panel meeting but still provided SERs with the information available at the time, held a standard Panel Outreach meeting to collect verbal advice and recommendations from SERs, and provided the standard 14-day written comment period to SERs. The EPA received substantial input from the SERs, and the Panel report describes recommendations made by the Panel on measures the Administrator should consider that would minimize the economic impact of the proposed rule on small entities. The EPA complied with the RFA. In addition, we met with representatives of small businesses, small rural cooperatives, and small governments a number of times during the regulatory development process to discuss their issues and concerns regarding the proposed MATS rule for EGUs.

Comment: One commenter requested that the EPA work with utilities such that new regulations are as flexible and cost efficient as possible.

Response: In developing the final rule, the EPA has considered all information provided prior to, as well as in response to, the proposed rule. The EPA has endeavored to make the final regulations flexible and cost-efficient while adhering to the requirements of

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the CAA. The final rule includes a number of flexibilities, such as those related to monitoring requirements, that will lower costs and simplify compliance for small businesses and local governments.

Comment: One commenter was concerned about the ability of small entities or nonprofit utilities such as those owned and/or operated by rural electric co-op utilities, and municipal utilities to comply with the proposed standards within 3 years. The commenter believes that the EPA disregarded the SER panelists who explained that under these current economic conditions they have constraints on their ability to raise capital for the construction of control projects and to acquire the necessary resources in order to meet a 3-year compliance deadline. Two commenters expressed concern that smaller utilities and those in rural areas will be unable to get vendors to respond to their requests for proposals, because they will be able to make more money serving larger utilities.

Response: The preamble to the proposed rule (76 FR 25054; May 3, 2011) provides a detailed discussion of how the EPA determined compliance times for the proposed (and final) rule. The EPA has provided pursuant to CAA section 112(i)(3)(A) the maximum 3-year period for sources to come into compliance. Sources may also seek a 1-year extension of the compliance period from their Title V permitting authority if the source needs that time to install controls. *See* CAA section 112(i)(3)(B). If the situation described by commenters (*i.e.,* where small entities or nonprofit utilities constraints on ability to raise capital for construction of control projects and to acquire necessary resources) results in the source needing additional time to install controls, they would be in a position to request the 1-year extension.

Comment: Several commenters believe the EPA did not adequately consider the disproportionately large impact on smaller generating units. The commenters note the diseconomies in scale for pollution controls for such units. One commenter noted the rule will create a more serious compliance hurdle for small communities that depend on coal-fired generation to meet their base load demand. The commenter notes that by not subcategorizing units, the EPA is dictating a fuel switch due to the disproportionately high cost on small communities. The other commenter believes the MACT and NSPS standards are unachievable by going too far without really considering the impacts on small municipal units, as public power is critical to communities, jobs, economic viability and electric reliability. A generating and transmissions electric cooperative which qualifies as a small entity believes the rule will ultimately result in increased electricity costs to its members and will negatively impact the economies of the primarily rural areas that they serve. Another commenter believes there is no legal or factual basis for creating subcategories or weaker standards for state, tribal, or municipal governments or small entities that are operating obsolete units, particularly given the current market situation and applicable equitable factors. The commenter suggests both the EPA's and SBA's analyses focus exclusively on the effects on entities causing HAP emissions and primarily on those operating obsolete EGUs, and fail to consider either impacts on downwind businesses and governments or the positive impacts on small entities and governments owning and operating competing, clean and modern EGUs.

Response: The EPA disagrees with the commenters' belief that the impacts on smaller generating units were not adequately considered when developing the rule. The EPA determined the number of potentially impacted small entities and assessed the potential impact of the proposed action on small entities, including municipal units. A similar assessment was conducted in support of the final action. Specifically, the EPA estimated the incremental net annualized compliance cost, which is a function of the change in capital and operating costs, fuel costs, and change in revenue. The projected compliance cost was considered relative to the projected revenue from generation. Thus, the EPA's analysis accounts not only for the additional costs these entities face resulting from compliance, but also the impact of higher electricity prices. The EPA evaluated suggestions from SERs, including subcategorization recommendations. In the preamble to the proposed rule, the EPA explains that, normally, any basis for subcategorizing must be related to an effect on emissions, rather than some difference which does not affect emissions performance. The EPA does not see a distinction between emissions from smaller generating units versus larger units. The EPA acknowledges the comment that there is no legal or factual basis for creating subcategories or weaker standards for state, tribal, or municipal governments or small entities that are operating obsolete units.

Comment: One commenter notes that the EPA recognizes LEEs in the rule such that they should receive less onerous monitoring requirements; however, the EPA does not recognize that small and LEEs also need and merit more flexible and achievable pollution control requirements. The commenter notes that the capital costs for emissions control at small utility units is disproportionately high due to inefficiencies in Hg removal, space constraints for control technology retrofits, and the fact that small units have fewer rate base customers across which to spread these costs. The commenter cites the Michigan Department of Environmental Quality report titled "Michigan's Mercury Electric Utility Workgroup, Final Report on Mercury Emissions from Coal-Fired Power Plants," (June 2005). The commenter notes that the EPA has addressed such concerns previously, citing the RIA for the 1997 8-hour ozone standard. The commenter also suggests smaller utility systems generally have less capital to invest in pollution control than larger, investor-owned systems, due to statutory inability to borrow from the private capital markets, statutory debt ceilings, limited bonding capacity, borrowing limitations related to fiscal strain posed by other, non-environmental factors, and other limitations.

Response: The EPA acknowledges that the rule contains reduced monitoring requirements for existing units that qualify as LEEs. Although the EPA does not believe that reduced pollution control requirements are warranted for LEEs, including small entity LEEs, we believe that flexible and achievable pollution control requirements are promoted through alternative standards, alternative compliance options, and emissions averaging as a means of demonstrating compliance with the standards for existing EGUs.

Comment: One commenter believes that the EPA should develop more limited monitoring requirements for small EGUs. The commenter notes small entities do not possess the monetary resources, manpower, or technical expertise needed to operate cutting-edge monitoring techniques such as Hg CEMS and PM CEMS. The commenter notes the EPA could have identified monitoring alternatives to the SER panel for consideration.

Response: The EPA provided monitoring alternatives to using PM CEMS, HCl CEMS, and Hg CEMS in its proposed standards and in this final rule. The continuous compliance alternatives are available to all affected sources, including small entities. As alternatives to the use of PM CEMS and HCl CEMS, sources are allowed to

conduct additional performance testing. Sorbent trap monitoring is allowed in lieu of Hg CEMS.

Comment: Several commenters believe the EPA has not sufficiently complied with the requirements of the RFA or adequately considered the impact this rulemaking would have on small entities. One commenter believes the EPA has not engaged in meaningful outreach and consultation with small entities and therefore recommends that the EPA seek to revise the court-ordered deadlines to which this rulemaking is subject, re-convene the SBAR panel, prepare a new initial regulatory flexibility analysis (IRFA), and issue it for additional public comment prior to final rulemaking. The commenter believes the IRFA does not sufficiently consider impacts on small entities as identified in the SBAR Panel Report. The commenter believes it is not apparent that the EPA considered the recommendations of the Panel. The commenter believes the description of significant alternatives in the IRFA is almost entirely quoted from the SBAR Panel Report, which the commenter does not believe is an adequate substitute for the EPA's own analysis of alternatives. The commenter also notes the EPA does not discuss the potential impacts of its decisions on small entities or the impacts of possible flexibilities. Where the EPA does consider regulatory alternatives in principle, the commenter believes it does not provide sufficient support for its decisions to understand on what basis the EPA rejected alternatives that may or may not have reduced burden on small entities while meeting the stated objectives of the rule. Additionally, the commenter notes that the EPA did not evaluate the economic or environmental impacts of significant alternatives to the proposed rule. One commenter believes that the EPA's stated reasons for declining to specify or analyze an area source standard are inadequate under the RFA. The commenter believes the EPA must give serious consideration to regulatory alternatives that accomplish the stated objectives of the CAA while minimizing any significant economic impacts on small entities and that the EPA has a duty to specify and analyze this option or to more clearly state its policy reasons for excluding serious consideration of a separate standard for area sources. A commenter believes the EPA did not fully consider the subcategorization of sources such as boilers designed to burn lignite coals versus other fossil fuels, especially in regard to non-mercury metal and acid gas emissions. The commenter references the SBAR Panel Report suggestion provided in the preamble of the proposed rule that the EPA consider developing an area source vs. major source distinction for the source category and the EPA's response. Another commenter is concerned that the recommendations made by the SER participants were ignored and not discussed in the rulemaking. Specifically, the commenter notes the EPA did not discuss subcategorizing by age, type of plant, fuel, physical space constraints or useful anticipated life of the plant. Nor did the EPA establish GACT for smaller emitters to alleviate regulatory costs and operational difficulties. A commenter believes it is likely that different numerical or work practice standards are appropriate for area sources of HAP.

Response: The EPA disagrees with one commenter's assertion that the agency has not complied with the requirements of the RFA. The EPA complied with both the letter and spirit of the RFA, notwithstanding the constraints of the court-ordered deadline. For example, the EPA notified the Chief Counsel for Advocacy of the SBA of its intent to convene a Panel; compiled a list of SERs for the Panel to consult with; and convened the Panel. The Panel met with SERs to collect their advice and recommendations; reviewed the EPA materials; and drafted a report of Panel findings. The EPA further disagrees with the commenter's assertion that the EPA's IRFA does not sufficiently consider impacts on small entities. The EPA's IRFA, which is included in chapter 10 of the RIA for the proposed rule, addresses the statutorily required elements of an IRFA, such as the economic impact of the proposed rule on small entities and the Panel's findings.

The EPA disagrees with the comment that recommendations made by the SERs were not considered or discussed in the proposed rulemaking such as recommendations regarding subcategorization and separate GACT standards for area sources. The preamble to the proposed standards includes a detailed discussion of how the EPA determined which subcategories and sources would be regulated (76 FR 25036–25037; May 3, 2011). In that discussion, the EPA explains the rationale for its proposed subcategories based on five unit design types. In addition, the EPA acknowledges the subcategorization suggestions from the SERs and explains its reasons for not subcategorizing on those bases. The preamble to the proposed standards also includes a discussion of the SERs' suggestion that area source EGUs be distinguished from major-source EGUs and the EPA's reasons for not making that distinction (76 FR 25020–25021; May 3, 2011).

The EPA also disagrees with the suggestion that the Agency pursue an extension of the timeline for final rulemaking such that the SBAR Panel can be reconvened and a new IRFA can be prepared and released for public comment prior to the final rulemaking. The EPA entered into a Consent Decree to resolve litigation alleging that the EPA failed to perform a non-discretionary duty to promulgate CAA section 112(d) standards for EGUs. *See American Nurses Ass'n* v. *EPA,* 08–2198 (D.D.C.). That Decree required the EPA to sign the final MATS rule by November 16, 2011, unless the agency sought to extend the deadline consistent with the requirements of the modification provision of the Consent Decree. The EPA and Plaintiffs stipulated to a 30-day extension consistent with the modification provisions of the Consent Decree and the rule must be signed no later than December 16, 2011. If plaintiffs in the *American Nurses* litigation objected to an additional extension request, which we believe would have been likely, the Agency would have had to file a motion with the Court seeking an extension of the deadline. Consistent with governing case law, the Agency would have been required to demonstrate in its motion for extension that it was impossible to finalize the rule by the deadline provided in the Consent Decree. *See Sierra Club* v. *Jackson,* Civil Action No. 01–1537 (D.D.C.) (Opinion of the Court denying EPA's motion to extend a consent decree deadline). The EPA negotiated a 30-day extension and was able to complete the rule by December 16, 2011; accordingly, the Agency had no basis for seeking a further extension of time.

A detailed description of the changes made to the rule since proposal, including those made as a result of feedback received during the public comment process can be found in sections VI (NESHAP) and X (NSPS) of this preamble. Changes explained in the identified sections include those related to applicability; subcategorization; work practices; periods of startup, shutdown, and malfunction; initial testing and compliance; continuous compliance; and notification, recordkeeping, and reporting.

4. Description and Estimate of the Affected Small Entities

For the purposes of assessing the impacts of MATS on small entities, a small entity is defined as:

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(1) A small business according to the Small Business Administration size standards by the North American Industry Classification System (NAICS) category of the owning entity. The range of small business size standards for electric utilities is 4 billion kilowatt hours (kWh) of production or less;

(2) A small government jurisdiction that is a government of a city, county, town, district, or special district with a population of less than 50,000; and

(3) A small organization that is any not for profit enterprise that is independently owned and operated and is not dominant in its field.

The EPA examined the potential economic impacts to small entities associated with this rulemaking based on assumptions of how the affected entities will install control technologies in compliance with MATS. This analysis does not examine potential indirect economic impacts associated with this rule, such as employment effects in industries providing fuel and pollution control equipment, or the potential effects of electricity price increases on industries and households.

The EPA used Velocity Suite's Ventyx data as a basis for identifying plant ownership and compiling the list of potentially affected small entities. The Ventyx dataset contains detailed ownership and corporate affiliation information. The analysis focused only on those EGUs affected by the rule, which includes units burning coal, oil, petroleum coke, or coal refuse as the primary fuel, and excludes any combustion turbine units or EGUs burning natural gas. Also, because the rule does not affect combustion units with an equivalent electricity generating capacity up to 25 MW, small entities that do not own at least one combustion unit with a capacity greater than 25 MW were removed from the dataset. For the affected units remaining, boiler and generator capacity, heat input, generation, and emissions data were aggregated by owner and then by parent company. Entities with more than 4 billion kWh of annual electricity generation were removed from the list, as were municipal owned entities with a population greater than 50,000. For cooperatives, investor owned utilities, and subdivisions that generate less than 4 billion kWh of electricity annually but which may be part of a large entity, additional research on power sales, operating revenues, and other business activities was performed to make a final determination regarding size. Finally, small entities for which the IPM does not project generation in 2015 in the base case were omitted from the analysis because they are not projected to be operating and, thus, are not projected to face the costs of compliance with the rule. After omitting entities for the reasons above, the EPA identified a total of 82 potentially affected small entities that are affiliated with 102 EGUs.

5. Compliance Cost Impacts

The number of potentially affected small entities by ownership type and potential impacts of MATS are presented in Chapter 7 of the RIA and summarized here. The EPA estimated the annualized net compliance cost to small entities to be approximately $106 million in 2015 (2007$).

The EPA assessed the economic and financial impacts of the final rule using the ratio of compliance costs to the value of revenues from electricity generation, and our results focus on those entities for which this measure could be greater than 1 percent or 3 percent. Of the 82 small entities identified, The EPA's analysis shows 40 entities may experience compliance costs greater than 1 percent of base generation revenues in 2015, and 35 may experience compliance costs greater than 3 percent of base revenues. Also, all generating capacity at 3 small entities is projected to be uneconomic to maintain. In this analysis, the cost of withdrawing a unit as uneconomic is estimated as the base case profit that is forgone by not operating under the policy case. Because 35 of the 82 total units, or more than 40 percent, are estimated to incur compliance cost greater than 3 percent of base revenues, the EPA has concluded that it cannot certify that there will be no significant economic impact on a substantial number of small entities (SISNOSE) for this rule. Results for small entities discussed here do not account for the reality that electricity markets are regulated in parts of the country. Entities operating in regulated or cost-of-service markets should be able to recover all of their costs of compliance through rate adjustments.

Note that the estimated costs for small entities are significantly lower than those estimated by the EPA for the MATS proposal (which were $379 million). This is driven by a small group of units (less than 6 percent) which were projected to be uneconomic to operate under the proposal (and hence incurred lost profits due to lost electricity revenues), but are now projected to continue their operations under MATS. In addition, the EPA's modeling indicates one unit that would have operated at a low capacity factor under the base case would find it economical to increase its generation significantly under MATS to meet electricity demand in its region. Excluding this unit, the total cost impacts across all entities would be roughly $175 million. Changes in compliance behavior for this small group of units, in particular the one unit which operates at a higher capacity factor, has a substantial impact on total costs as their increased generation revenues offsets a large portion of the compliance costs.

The most significant components of incremental costs to these entities are changes in electricity revenues, followed by the increased capital and operating costs for retrofits. Capital and operating costs increase across all ownership types, but the direction of changes in electricity revenues varies among ownership types. All ownership types, with the exception of private entities, experience a net gain in electricity revenues under the MATS, unlike projections from the EPA's modeling during the proposal, where only municipals benefitted from higher electricity revenues. The change in electricity revenue takes into account both the profit lost from units that do not operate under the policy case and the difference in revenue for operating units under the policy case. According to the EPA's modeling, an estimated 274 MW of capacity owned by small entities are considered uneconomic to operate under the policy case, resulting in a net loss of $13 million (in 2007$) in profits. On the other hand, many operating units actually increase their electricity revenue due to higher electricity prices under MATS. In addition, as mentioned above, the EPA's modeling indicates one unit finds it economical to increase its capacity factor significantly under the policy case which results in significantly higher revenues offsetting the costs.

6. Description of Steps To Minimize Impacts on Small Entities

Consistent with the requirements of the RFA and SBREFA, the EPA has taken steps to minimize the significant economic impact on small entities. Because this rule does not affect units with a generating capacity of less than 25 MW, small entities that do not own at least one generating unit with a capacity greater than 25 MW are not subject to the rule. According to the EPA's analysis, among the coal- and oil-fired EGUs (*i.e.,* excluding combined cycle gas turbines and gas combustion turbines) about 26 potentially small entities only own EGUs with a capacity less than or equal to 25 MW, and none of those entities are subject to the final

rule based on the statutory definition of potentially regulated units.

For units affected by the proposed rule, the EPA considered a number of comments received, both during the Small Business Advocacy Review (SBAR) Panel and the public comment period. While none of the alternatives adopted is specifically applied to small entities, the EPA believes these modifications will make compliance less onerous for all regulated units, including those owned by small entities.

a. Work practice standards. The EPA proposed numerical emission standards that would apply at all times, including during periods of startup and shutdown. After reviewing comments and other data regarding the nature of these periods of operation, the EPA is finalizing a work practice standard for periods of startup and shutdown. The EPA is also finalizing work practice standards for organic HAP from all subcategories of EGUs. Descriptions of the work practice requirements for startup and shutdown, as well as organic HAP and limited-use liquid oil-fired EGUs, can be found in section VI.D–E. of the preamble.

b. Continuous compliance and notification, record-keeping, and reporting. The final rule greatly simplifies the continuous compliance requirements and provides two basic approaches for most situations: use of continuous monitoring and periodic testing. The frequency of periodic testing has been decreased from monthly in the proposal to quarterly in the final rule. In addition to simplifying compliance, the EPA believes these changes considerably reduce the overall burden associated with recordkeeping and reporting. These changes to the final rule are described in more detail in Section VI.G–H of this preamble.

c. Subcategorization. The Small Entity Representatives on the SBAR Panel were generally supportive of subcategorization and suggested a number of additional subcategories the EPA should consider when developing the final rule. Although it was not consistent with the statute to adopt the proposed subcategories, the EPA maintained the existing subcategories and split the "liquid oil-fired units" subcategory into three subcategories—continental, non-continental units, and limited-use units.

d. MACT floor calculations. As recommended by the EPA SBAR Panel representative, the EPA established the MACT floors using all the available ICR data that was received to the maximum extent possible consistent with the CAA requirements. The Agency believes this approach reasonably ensures that the emission limits selected as the MACT floors adequately represent the level of emissions actually achieved by the average of the units in the top 12 percent, considering operational variability of those units.

e. Alternatives not adopted. The EPA did not adopt several of the suggestions posed either during the SBAR Panel or public comment period. The EPA did not propose a percent reduction standard as an alternative to the concentration-based MACT floor. The percent reduction format for Hg and other HAP emissions would not have addressed the EPA's consideration of coal preparation practices that remove Hg and other HAP before firing. Also, to account for the coal preparation practices, sources would be required to track the HAP concentrations in coal from the mine to the stack, and not just before and after the control device(s), and such an approach would be difficult to implement and enforce. Furthermore, the EPA does not believe the percent reduction standard is in line with the Court's interpretation of the CAA section 112 requirements. Even if we believed it was appropriate to establish a percent reduction standard, we do not have the data necessary to establish percent reduction standards for HAP, as explained further in the response to comments document.

The EPA determined not to establish GACT standards for area sources for a number of reasons. The data show that similar HAP emissions and control technologies are found on both major and area sources greater than 25 MW, and some large units are synthetic area sources. In fact, because of the significant number of well-controlled EGUs of all sizes, we believe it would be difficult to make a distinction between MACT and GACT. Moreover, the EPA believes the standards for area source EGUs should reflect MACT, rather than GACT, because there is no essential difference between area source and major source EGUs with respect to emissions of HAP.

The EPA determined not to exercise its discretionary authority to establish health-based emission standards for HCl and other HAP acid gases. Given the limitations of the currently available information (*e.g.*, the HAP mix where EGUs are located, and the cumulative impacts of respiratory irritants from nearby sources), the environmental effects of HCl and the other acid gas HAP, and the significant co-benefits from reductions in criteria pollutants the EPA determined that setting a conventional MACT standard for HCl and the other acid gas HAP was the appropriate course of action.

As required by SBREFA section 212, the EPA also is preparing a Small Entity Compliance Guide to help small entities comply with this rule. Small entities will be able to obtain a copy of the Small Entity Compliance guide at the following Web site: *http://www.epa.gov/airquality/powerplanttoxics/actions.html.*

D. Unfunded Mandates Reform Act of 1995

Title II of the UMRA of 1995, Public Law 104–4, establishes requirements for federal agencies to assess the effects of their regulatory actions on state, local, and tribal governments and the private sector. Under UMRA section 202, we generally must prepare a written statement, including a cost-benefit analysis, for proposed and final rules with "Federal mandates" that may result in expenditures to state, local, and tribal governments, in the aggregate, or to the private sector, of $100 million or more in any 1 year. Before promulgating a rule for which a written statement is needed, UMRA section 205 generally requires us to identify and consider a reasonable number of regulatory alternatives and adopt the least costly, most cost-effective or least burdensome alternative that achieves the objectives of the rule. The provisions of UMRA section 205 do not apply when they are inconsistent with applicable law. Moreover, UMRA section 205 allows us to adopt an alternative other than the least costly, most cost-effective or least burdensome alternative if the Administrator publishes with the final rule an explanation why that alternative was not adopted. Before we establish any regulatory requirements that may significantly or uniquely affect small governments, including tribal governments, we must develop a small government agency plan under UMRA section 203. The plan must provide for notifying potentially affected small governments, enabling officials of affected small governments to have meaningful and timely input in the development of regulatory proposals with significant federal intergovernmental mandates, and informing, educating, and advising small governments on compliance with the regulatory requirements.

We have determined that this rule contains a federal mandate that may result in expenditures of $100 million or more for state, local, and tribal governments, in the aggregate, or the private sector in any 1 year. Accordingly, we have prepared a written statement entitled "Unfunded Mandates Reform Act Analysis" under

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UMRA section 202 that is within the RIA and which is summarized below.

1. Statutory Authority

As discussed elsewhere in this preamble, the statutory authority for this rulemaking is CAA section 112. Title III of the CAA Amendments was enacted to reduce nationwide air toxic emissions. CAA section 112(b) lists the 188 chemicals, compounds, or groups of chemicals deemed by Congress to be HAP. These toxic air pollutants are to be regulated by NESHAP.

CAA section 112(d) directs us to develop NESHAP which require existing and new major sources to control emissions of HAP using MACT-based standards. This NESHAP applies to all coal- and oil-fired EGUs.

In compliance with UMRA section 205(a), we identified and considered a reasonable number of regulatory alternatives. Additional information on the costs and environmental impacts of these regulatory alternatives were presented in the RIA for the rulemaking.

The regulatory alternative upon which this rule is based represents the MACT floor for all regulated pollutants for all but one EGU subcategory for all but one regulated pollutant for that subcategory. These MACT floor-based standards represent the least costly and least burdensome alternative. Beyond-the-floor emission limits for Hg are for existing coal-fired EGUs in the subcategory for low rank virgin coal EGUs.

2. Social Costs and Benefits

The RIA prepared for this rule including the Agency's assessment of costs and benefits is in the docket.

It is estimated that HAP would be reduced by thousands of tons in 2015, relative to the base case, including reductions in HCl, HF, metallic HAP (including Hg), and several other organic HAP from EGUs. Studies have determined a relationship between exposure to certain of these HAP and the onset of cancer; however, the Agency is unable to provide a monetized estimate of the HAP benefits at this time. In addition, significant reductions in $PM_{2.5}$ and SO_2 will occur, including approximately 53 thousand tons of $PM_{2.5}$ and over 1 million tons of SO_2. These reductions will occur by 2016 and are expected to continue throughout the life of the affected sources. The major health effect associated with reducing $PM_{2.5}$ and $PM_{2.5}$ precursors (such as SO_2) is a reduction in premature mortality. Other health effects associated with $PM_{2.5}$ emission reductions include avoiding cases of chronic bronchitis, heart attacks, asthma attacks, and work-lost days (*i.e.,* days when employees are unable to work). Although we are unable to monetize the benefits associated with the HAP emissions reductions other than for Hg or all benefits associated with Hg reductions, we are able to monetize the benefits associated with the $PM_{2.5}$ and SO_2 emissions reductions. For SO_2 and $PM_{2.5}$, we estimated the benefits associated with health effects of PM but were unable to quantify all categories of benefits (particularly those associated with ecosystem and visibility effects). Our estimates of the monetized benefits in 2016 associated with the implementation of the final rule range from $37 billion to $90 billion (2007 dollars) when using a 3 percent discount rate or from $33 billion to $81 billion (2007 dollars) when using a 7 percent discount rate). Our estimate of costs is $9.6 billion (2007 dollars). For more detailed information on the benefits and costs estimated for this rulemaking, refer to the RIA in the docket.

3. Future and Disproportionate Costs

The UMRA requires that we estimate, where accurate estimation is reasonably feasible, future compliance costs imposed by this rule and any disproportionate budgetary effects. Our estimates of the future compliance costs of this rule are discussed previously in this preamble.

The EPA assessed the economic and financial impacts of the rule on government-owned entities using the ratio of compliance costs to the value of revenues from electricity generation, and our results focus on those entities for which this measure could be greater than 1 percent or 3 percent of base revenues. The EPA projects that 42 government entities will have compliance costs greater than 1 percent of base generation revenue in 2016, and 32 may experience compliance costs greater than 3 percent of base revenues. Overall, 6 units owned by government entities are expected to retire. The most significant components of incremental costs to these entities are the increased capital and operating costs, followed by changes in electricity revenues. For more details on these results and the methodology behind their estimation, see the results included in chapter 7 of the RIA.

4. Effects on the National Economy

The UMRA requires that we estimate the effect of this rule on the national economy. To the extent feasible, we must estimate the effect on productivity, economic growth, full employment, creation of productive jobs, and international competitiveness of the U.S. goods and services, if we determine that accurate estimates are reasonably feasible and that such effect is relevant and material.

The nationwide economic impact of this rule is presented in the RIA in the docket. This analysis provides estimates of the effect of this rule on some of the categories mentioned above.

The results of the economic impact analysis are summarized previously in this preamble. The results show that, relative to baseline, there will be an average 3.1 percent increase in electricity price on average nationwide in 2016, with the range of increases from 1.3 percent to 6.3 percent in regions throughout the U.S., and a less than 1 percent increase in natural gas price nationwide in 2016. The roughly 3 percent incremental price effect of this rule is small relative to the changes observed in the absolute levels of electricity prices over the last 50 years, which have ranged from as much as 23 percent lower (in 1969) to as much as 23 percent higher (in 1982) than prices observed in 2010.[377] Power generation from coal-fired plants will fall by about 2 percent nationwide in 2016. No region of the U.S. is expected to experience a double-digit increase in retail electricity prices in 2015 or in any year later than that, according to the Agency's analysis, as a result of this rule. To put the electricity price effects in context, the roughly 3 percent incremental increase in aggregate end-user electricity prices projected to occur over the next 4 years is about the same as the 3 percent absolute average change in total end-user electricity prices observed on an annual basis.[378] Furthermore, the roughly 3 percent incremental price effect of this rule is small relative to the changes observed in the absolute levels of electricity prices over the last 50 years, which have ranged from as much as 23 percent lower (in 1969) to as much as 23 percent higher (in 1982) than prices observed in 2010.[379] Even with this rule in effect, electricity prices are projected to be lower in 2015 and 2020 than they were in 2010.[380]

5. Consultation With Government

The UMRA requires that we describe the extent of the Agency's prior consultation with affected state, local,

[377] EIA Annual Energy Outlook 2010 annual total electricity prices from 1960 to 2010, Table 8–10.

[378] EIA Annual Energy Outlook 2010 annual total electricity prices from 1960 t0 2010, Table 8–10.

[379] Ibid.

[380] Ibid., EIA AEO 2010, Table–10 for price levels; and Chapterr 3 of the RIA for electricity price differential.

and tribal officials, summarize the officials' comments or concerns, and summarize our response to those comments or concerns. In addition, UMRA section 203 requires that we develop a plan for informing and advising small governments that may be significantly or uniquely impacted by a regulatory action. Consistent with the intergovernmental consultation provisions of UMRA section 204, the EPA initiated consultations with governmental entities affected by this rule. The EPA invited the following 10 national organizations representing state and local elected officials to a meeting held on October 27, 2010, in Washington, DC: (1) National Governors Association; (2) National Conference of State Legislatures, (3) Council of State Governments, (4) National League of Cities, (5) U.S. Conference of Mayors, (6) National Association of Counties, (7) International City/County Management Association, (8) National Association of Towns and Townships, (9) County Executives of America, and (10) Environmental Council of States. These 10 organizations of elected state and local officials have been identified by the EPA as the "Big 10" organizations appropriate to contact for purpose of consultation with elected officials. The purposes of the consultation were to provide general background on the rule, answer questions, and solicit input from state/local governments. During the meeting, officials asked clarifying questions regarding CAA section 112 requirements and central decision points presented by the EPA (*e.g.*, use of surrogate pollutants to address HAP, subcategorization of source category, assessment of emissions variability). They also expressed uncertainty with regard to how utility boilers owned/operated by state and local entities would be impacted, as well as with regard to the potential burden associated with implementing the rule on state and local entities (*i.e.*, burden to re-permit affected EGUs or update existing permits). Officials requested, and the EPA provided, addresses associated with the 112 state and local governments estimated to be potentially impacted by the rule. The EPA has not received additional questions or requests from state or local officials.

Consistent with UMRA section 205, the EPA has identified and considered a reasonable number of regulatory alternatives. Because the potential existed for a significant impact for substantial number of small entities, the EPA convened a SBAR Panel to obtain advice and recommendation of representatives of the small entities that potentially would be subject to the requirements of the rule. As part of that process, the EPA considered several options, which are discussed previously in this preamble. Those options included establishing emission limits, establishing work practice standards, establishing subcategories, and consideration of monitoring options. The regulatory alternative selected is a combination of the options considered and includes provisions regarding a number of the recommendations resulting from the SBAR Panel process as described below (see the Regulatory Flexibility Act discussion in this section of the preamble for more detail).

E. Executive Order 13132, Federalism

Under EO 13132, the EPA may not issue an action that has federalism implications, that imposes substantial direct compliance costs, and that is not required by statute, unless the federal government provides the funds necessary to pay the direct compliance costs incurred by state and local governments, or the EPA consults with state and local officials early in the process of developing the final action.

The EPA has concluded that this action may have federalism implications, because it may impose substantial direct compliance costs on state or local governments, and the federal government will not provide the funds necessary to pay those costs. Accordingly, the EPA provides the following federalism summary impact statement as required by section 6(b) of EO 13132.

Based on estimates in the RIA, provided in the docket, the final rule may have federalism implications because the rule may impose approximately $294 million in annual direct compliance costs on an estimated 96 state or local governments. Specifically, we estimate that there are 80 municipalities, 5 states, and 11 political subdivisions (*i.e.*, a public district with territorial boundaries embracing an area wider than a single municipality and frequently covering more than one county for the purpose of generating, transmitting and distributing electric energy) that may be directly impacted by this final rule. Responses to the EPA's 2010 ICR were used to estimate the nationwide number of potentially impacted state or local governments. As previously explained, this 2010 survey was submitted to all coal- and oil-fired EGUs listed in the 2007 version of DOE/EIA's "Annual Electric Generator Report," and "Power Plant Operations Report."

The EPA consulted with state and local officials in the process of developing the rule to permit them to have meaningful and timely input into its development. The EPA met with 10 national organizations representing state and local elected officials to provide general background on the rule, answer questions, and solicit input. In the final rule, EPA has provided flexibilities that will lower compliance costs for these entities. The EPA also recognizes that municipalities may need a longer compliance timeframe because of required approval processes.

F. Executive Order 13175, Consultation and Coordination With Indian Tribal Governments

Subject to EO 13175 (65 FR 67249; November 9, 2000) the EPA may not issue a regulation that has tribal implications, that imposes substantial direct compliance costs, and that is not required by statute, unless the federal government provides the funds necessary to pay the direct compliance costs incurred by tribal governments, or the EPA consults with tribal officials early in the process of developing the proposed regulation and develops a tribal summary impact statement. Executive Order 13175 requires the EPA to develop an accountable process to ensure "meaningful and timely input by Tribal officials in the development of regulatory policies that have Tribal implications."

The EPA has concluded that this action may have tribal implications. The EPA offered consultation with tribal officials early in the regulation development process to permit them an opportunity to have meaningful and timely input. Consultation letters were sent to 584 tribal leaders and provided information regarding the EPA's development of this rule and offered consultation. At the request of the tribes, three consultation meetings were held: December 7, 2010, with the Upper Sioux Community of Minnesota; December 13, 2010, with Moapa Band of Paiutes, Forest County Potawatomi, Standing Rock Sioux Tribal Council, and Fond du Lac Band of Chippewa; January 5, 2011, with the Forest County Potawatomi, and a representative from the National Tribal Air Association (NTAA). In these meetings, the EPA presented the authority under the CAA used to develop these rules and an overview of the industry and the industrial processes that have the potential for regulation. Tribes expressed concerns about the impact of EGUs in Indian country. Specifically, they were concerned about potential Hg deposition and the impact on the water resources of the tribes, with particular concern about the impact on subsistence

lifestyles for fishing communities, the cultural impact of impaired water quality for ceremonial purposes, and the economic impact on tourism. In light of these concerns, the tribes expressed interest in an expedited implementation of the rule. Other concerns expressed by tribes related to how the Agency would consider variability in setting the standards, and the use of tribal-specific fish consumption data from the tribes in our assessments. They were not supportive of using work practice standards as part of the rule, and asked the Agency to consider going beyond the MACT floor to offer more protection for the tribal communities.

In addition to these consultations, the EPA also conducted outreach on this rule through presentations at the National Tribal Forum in Milwaukee, WI; phone calls with the NTAA; and a webinar for tribes on the proposed rule. The EPA specifically requested tribal data that could support the appropriate and necessary analyses and the RIA for this rule. In addition, the EPA held individual consultations with the Navajo Nation on October 12, 2011; as well as the Gila River Indian Community, Ak-Chin Indian Community, and the Hopi Nation on October 14, 2011. These tribes expressed concerns about the impact of the rule on the Navajo Generating Station (NGS), the impact on the cost of the water allotted to the tribes from the Central Arizona Project (CAP), the impact on tribal revenues from the coal mining operations (*i.e.*, assumptions about reduced mining if NGS were to retire one or more units), and the impacts on employment of tribal members at both the NGS and the mine. More specific comments can be found in the docket.

The EPA will continue to work with these and other potentially affected tribes as this final rule is implemented.

G. Executive Order 13045, Protection of Children From Environmental Health Risks and Safety Risks

This final rule is subject to EO 13045 (62 FR 19885; April 23, 1997) because it is an economically significant regulatory action as defined by EO 12866, and EPA believes that the environmental health or safety risk addressed by this action may have a disproportionate effect on children. Accordingly, we have evaluated the environmental health or safety effects of the standards on children.

Although this final rule is based on technology performance, the standards are designed to protect against hazards to public health with an adequate margin of safety as described in Section III of this preamble. The protection offered by this rule is particularly important for children, especially the developing fetus. As referenced in Chapter 4 of the RIA, "Mercury and Other HAP Benefits Analysis," children are more vulnerable than adults to many HAP emitted by EGUs due to differential behavior patterns and physiology. These unique susceptibilities were carefully considered in a number of different ways in the analyses associated with this rulemaking, and are summarized in the RIA. We also estimate substantial health improvements for children in the form of 130,000 fewer asthma attacks, 3,100 fewer emergency room visits due to asthma, 6,300 fewer cases of acute bronchitis, and approximately 140,000 fewer cases of upper and lower respiratory illness.

H. Executive Order 13211, Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use

Executive Order 13211 (66 FR 28355; May 22, 2001) requires EPA to prepare and submit a Statement of Energy Effects to the Administrator of the Office of Information and Regulatory Affairs, OMB, for actions identified as "significant energy actions." This action, which is a significant regulatory action under EO 12866, is likely to have a significant adverse effect on the supply, distribution, or use of energy. We have prepared a Statement of Energy Effects for this action as follows.

We estimate a 3.1 percent price increase for electricity nationwide in 2016 and a less than 2 percent percentage fall in coal-fired power production as a result of this rule. The EPA projects that electric power sector-delivered natural gas prices will increase by about 0.6 percent over the 2015 to 2030 timeframe. For more information on the estimated energy effects, please refer to the economic impact analysis for this final rule. The analysis is available in the RIA, which is in the public docket.

I. National Technology Transfer and Advancement Act

Section 12(d) of the National Technology Transfer and Advancement Act (NTTAA) of 1995 (Pub. L. 104–113; 15 U.S.C. 272 note) directs the EPA to use voluntary consensus standards in its regulatory activities unless to do so would be inconsistent with applicable law or otherwise impractical. Voluntary consensus standards are technical standards (*e.g.*, materials specifications, test methods, sampling procedures, business practices) that are developed or adopted by voluntary consensus standards bodies. The NTTAA directs the EPA to provide Congress, through OMB, explanations when the Agency decides not to use available and applicable voluntary consensus standards.

This rulemaking involves technical standards. The EPA cites the following standards in the final rule: EPA Methods 1, 2, 2A, 2C, 2F, 2G, 3A, 3B, 4, 5, 5D, 17, 19, 23, 26, 26A, 29, 30B of 40 CFR part 60 and Method 320 of 40 CFR part 63. Consistent with the NTTAA, the EPA conducted searches to identify voluntary consensus standards in addition to these EPA methods. No applicable voluntary consensus standards were identified for EPA Methods 2F, 2G, 5D, and 19. The search and review results have been documented and are placed in the docket for the proposed rule.

The three voluntary consensus standards described below were identified as acceptable alternatives to EPA test methods for the purposes of the final rule.

The voluntary consensus standard American National Standards Institute (ANSI)/American Society of Mechanical Engineers (ASME) PTC 19–10–1981, "Flue and Exhaust Gas Analyses [part 10, Instruments and Apparatus]" is cited in the final rule for its manual method for measuring the O_2, CO_2, and CO content of exhaust gas. This part of ANSI/ASME PTC 19–10–1981 is an acceptable alternative to Method 3B.

The voluntary consensus standard ASTM D6348–03 (Reapproved 2010), "Standard Test Method for Determination of Gaseous Compounds by Extractive Direct Interface Fourier Transform (FTIR) Spectroscopy" is acceptable as an alternative to Method 320 and is cited in the final rule, but with several conditions: (1) The test plan preparation and implementation in the Annexes to ASTM D6348–03, Sections A1 through A8 are mandatory; and (2) In ASTM D6348–03 Annex A5 (Analyte Spiking Technique), the percent (%) R must be determined for each target analyte (Equation A5.5). In order for the test data to be acceptable for a compound, %R must be 70% ≥ R ≤ 130%. If the %R value does not meet this criterion for a target compound, the test data are not acceptable for that compound and the test must be repeated for that analyte (*i.e.*, the sampling and/or analytical procedure should be adjusted before a retest). The %R value for each compound must be reported in the test report, and all field measurements must be corrected with the calculated %R value for that compound by using the following

equation: *Reported Result = (Measured Concentration in the Stack × 100)/% R.*

The voluntary consensus standard ASTM D6784–02, "Standard Test Method for Elemental, Oxidized, Particle-Bound and Total Mercury in Flue Gas Generated from Coal-Fired Stationary Sources (Ontario Hydro Method)," is an acceptable alternative to use of EPA Method 29 for Hg only or Method 30B for the purpose of conducting relative accuracy tests of Hg continuous monitoring systems under this final rule. Because of the limitations of this method in terms of total sampling volume, it is not appropriate for use in performance testing under this rule. In addition to the voluntary consensus standards the EPA used in the final rule, the search for emissions measurement procedures identified 16 other voluntary consensus standards. The EPA determined that 14 of these 16 standards identified for measuring emissions of the HAP or other pollutants subject to emission standards in the final rule were impractical alternatives to EPA test methods for the purposes of this final rule. Therefore, the EPA did not adopt these standards for this purpose. The reasons for this determination for the 14 methods are discussed below, and the remaining 2 methods are discussed later in this section.

The voluntary consensus standard ASTM D3154–00, "Standard Method for Average Velocity in a Duct (Pitot Tube Method)," is impractical as an alternative to EPA Methods 1, 2, 3B, and 4 for the purposes of this rulemaking because the standard appears to lack in quality control and quality assurance requirements. Specifically, ASTM D3154–00 does not include the following: (1) proof that openings of standard pitot tube have not plugged during the test; (2) if differential pressure gauges other than inclined manometers (*e.g.,* magnehelic gauges) are used, their calibration must be checked after each test series; and (3) the frequency and validity range for calibration of the temperature sensors.

The voluntary consensus standard ASTM D3464–96 (Reapproved 2001), "Standard Test Method Average Velocity in a Duct Using a Thermal Anemometer," is impractical as an alternative to EPA Method 2 for the purposes of this rule primarily because applicability specifications are not clearly defined, *e.g.,* range of gas composition, temperature limits. Also, the lack of supporting quality assurance data for the calibration procedures and specifications, and certain variability issues that are not adequately addressed by the standard limit the EPA's ability to make a definitive comparison of the method in these areas.

The voluntary consensus standard ISO 10780:1994, "Stationary Source Emissions—Measurement of Velocity and Volume Flowrate of Gas Streams in Ducts," is impractical as an alternative to EPA Method 2 in this rule. The standard recommends the use of an L-shaped pitot, which historically has not been recommended by the EPA. The EPA specifies the S-type design which has large openings that are less likely to plug up with dust.

The voluntary consensus standard, CAN/CSA Z223.2–M86 (1999), "Method for the Continuous Measurement of Oxygen, Carbon Dioxide, Carbon Monoxide, Sulphur Dioxide, and Oxides of Nitrogen in Enclosed Combustion Flue Gas Streams," is unacceptable as a substitute for EPA Method 3A because it does not include quantitative specifications for measurement system performance, most notably the calibration procedures and instrument performance characteristics. The instrument performance characteristics that are provided are non-mandatory and also do not provide the same level of quality assurance as the EPA methods. For example, the zero and span/calibration drift is only checked weekly, whereas the EPA methods require drift checks after each run.

Two very similar voluntary consensus standards, ASTM D5835–95 (Reapproved 2001), "Standard Practice for Sampling Stationary Source Emissions for Automated Determination of Gas Concentration," and ISO 10396:1993, "Stationary Source Emissions: Sampling for the Automated Determination of Gas Concentrations," are impractical alternatives to EPA Method 3A for the purposes of this final rule because they lack in detail and quality assurance/quality control requirements. Specifically, these two standards do not include the following: (1) Sensitivity of the method; (2) acceptable levels of analyzer calibration error; (3) acceptable levels of sampling system bias; (4) zero drift and calibration drift limits, time span, and required testing frequency; (5) a method to test the interference response of the analyzer; (6) procedures to determine the minimum sampling time per run and minimum measurement time; and (7) specifications for data recorders, in terms of resolution (all types) and recording intervals (digital and analog recorders, only).

The voluntary consensus standard ISO 12039:2001, "Stationary Source Emissions—Determination of Carbon Monoxide, Carbon Dioxide, and Oxygen—Automated Methods," is not acceptable as an alternative to EPA Method 3A. This ISO standard is similar to EPA Method 3A, but is missing some key features. In terms of sampling, the hardware required by ISO 12039:2001 does not include a 3-way calibration valve assembly or equivalent to block the sample gas flow while calibration gases are introduced. In its calibration procedures, ISO 12039:2001 only specifies a two-point calibration while EPA Method 3A specifies a three-point calibration. Also, ISO 12039:2001 does not specify performance criteria for calibration error, calibration drift, or sampling system bias tests as in the EPA method, although checks of these quality control features are required by the ISO standard.

The voluntary consensus standard ASTM D6522–00, "Standard Test Method for the Determination of Nitrogen Oxides, Carbon Monoxide, and Oxygen Concentrations in Emissions from Natural Gas-Fired Reciprocating Engines, Combustion Turbines, Boilers and Process Heaters Using Portable Analyzers" is not an acceptable alternative to EPA Method 3A for measuring CO and O_2 concentrations for this final rule as the method is designed for application to sources firing natural gas.

The voluntary consensus standard ASME PTC–38–80 R85 (1985), "Determination of the Concentration of Particulate Matter in Gas Streams," is not acceptable as an alternative for EPA Method 5 because ASTM PTC–38–80 is not specific about equipment requirements, and instead presents the options available and the pros and cons of each option. The key specific differences between ASME PTC–38–80 and the EPA methods are that the ASME standard: (1) Allows in-stack filter placement as compared to the out-of-stack filter placement in EPA Methods 5 and 17; (2) allows many different types of nozzles, pitots, and filtering equipment; (3) does not specify a filter weighing protocol or a minimum allowable filter weight fluctuation as in the EPA methods; and (4) allows filter paper to be only 99 percent efficient, as compared to the 99.95 percent efficiency required by the EPA methods.

The voluntary consensus standard ASTM D3685/D3685M–98, "Test Methods for Sampling and Determination of Particulate Matter in Stack Gases," is similar to EPA Methods 5 and 17, but is lacking in the following areas that are needed to produce quality, representative particulate data: (1) Requirement that the filter holder temperature should be between 120°C and 134°C, and not just "above the acid dew-point"; (2) detailed specifications

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for measuring and monitoring the filter holder temperature during sampling; (3) procedures similar to EPA Methods 1, 2, 3, and 4, that are required by EPA Method 5; (4) technical guidance for performing the Method 5 sampling procedures, *e.g.,* maintaining and monitoring sampling train operating temperatures, specific leak check guidelines and procedures, and use of reagent blanks for determining and subtracting background contamination; and (5) detailed equipment and/or operational requirements, *e.g.,* component exchange leak checks, use of glass cyclones for heavy particulate loading and/or water droplets, operating under a negative stack pressure, exchanging particulate loaded filters, sampling preparation and implementation guidance, sample recovery guidance, data reduction guidance, and particulate sample calculations input.

The voluntary consensus standard ISO 9096:1992, "Determination of Concentration and Mass Flow Rate of Particulate Matter in Gas Carrying Ducts—Manual Gravimetric Method," is not acceptable as an alternative for EPA Method 5. Although sections of ISO 9096 incorporate EPA Methods 1, 2, and 5 to some degree, this ISO standard is not equivalent to EPA Method 5 for collection of PM. The standard ISO 9096 does not provide applicable technical guidance for performing many of the integral procedures specified in Methods 1, 2, and 5. Major performance and operational details are lacking or nonexistent, and detailed quality assurance/quality control guidance for the sampling operations required to produce quality, representative particulate data (*e.g.,* guidance for maintaining and monitoring train operating temperatures, specific leak check guidelines and procedures, and sample preparation and recovery procedures) are not provided by the standard, as in EPA Method 5. Also, details of equipment and/or operational requirements, such as those specified in EPA Method 5, are not included in the ISO standard, *e.g.,* stack gas moisture measurements, data reduction guidance, and particulate sample calculations.

The voluntary consensus standard CAN/CSA Z223.1–M1977, "Method for the Determination of Particulate Mass Flows in Enclosed Gas Streams," is not acceptable as an alternative for EPA Method 5. Detailed technical procedures and quality control measures that are required in EPA Methods 1, 2, 3, and 4 are not included in CAN/CSA Z223.1. Second, CAN/CSA Z223.1 does not include the EPA Method 5 filter weighing requirement to repeat weighing every 6 hours until a constant weight is achieved. Third, EPA Method 5 requires the filter weight to be reported to the nearest 0.1 milligram (mg), while CAN/CSA Z223.1 requires reporting only to the nearest 0.5 mg. Also, CAN/CSA Z223.1 allows the use of a standard pitot for velocity measurement when plugging of the tube opening is not expected to be a problem. The EPA Method 5 requires an S-shaped pitot.

The voluntary consensus standard EN 1911–1,2,3 (1998), "Stationary Source Emissions-Manual Method of Determination of HCl-Part 1: Sampling of Gases Ratified European Text-Part 2: Gaseous Compounds Absorption Ratified European Text-Part 3: Adsorption Solutions Analysis and Calculation Ratified European Text," is impractical as an alternative to EPA Methods 26 and 26A. Part 3 of this standard cannot be considered equivalent to EPA Method 26 or 26A because the sample absorbing solution (water) would be expected to capture both HCl and chlorine gas, if present, without the ability to distinguish between the two. The EPA Methods 26 and 26A use an acidified absorbing solution to first separate HCl and chlorine gas so that they can be selectively absorbed, analyzed, and reported separately. In addition, in EN 1911 the absorption efficiency for chlorine gas would be expected to vary as the pH of the water changed during sampling.

The voluntary consensus standard EN 13211 (1998), is not acceptable as an alternative to the Hg portion of EPA Method 29 primarily because it is not validated for use with impingers, as in the EPA method, although the method describes procedures for the use of impingers. This European standard is validated for the use of fritted bubblers only and requires the use of a side (split) stream arrangement for isokinetic sampling because of the low sampling rate of the bubblers (up to 3 liters per minute, maximum). Also, only two bubblers (or impingers) are required by EN 13211, whereas EPA Method 29 require the use of six impingers. In addition, EN 13211 does not include many of the quality control procedures of EPA Method 29, especially for the use and calibration of temperature sensors and controllers, sampling train assembly and disassembly, and filter weighing.

Two of the 16 voluntary consensus standards identified in this search were not available at the time the review was conducted for the purposes of the final rule because they are under development by a voluntary consensus body: ASME/BSR MFC 13M, "Flow Measurement by Velocity Traverse," for EPA Method 2 (and possibly 1); and ASME/BSR MFC 12M, "Flow in Closed Conduits Using Multiport Averaging Pitot Primary Flowmeters," for EPA Method 2.

Finally, in addition to the three voluntary consensus standards identified as acceptable alternatives to EPA methods required in the final rule, the EPA is also specifying four voluntary consensus standards in the rule for use in sampling and analysis of liquid oil samples for moisture content. These standards are: ASTM D95–05 (Reapproved 2010), "Standard Test Method for Water in Petroleum Products and Bituminous Materials by Distillation," ASTM D4006–11, "Standard Test Method for Water in Crude Oil by Distillation," ASTM D4177–95 (Reapproved 2010), "Standard Practice for Automatic Sampling of Petroleum and Petroleum Products," and ASTM D4057–06 (Reapproved 2011), "Standard Practice for Manual Sampling of Petroleum and Petroleum Products."

Table 5, section 4.1.1.5 of appendix A, and section 3.1.2 of appendix B to subpart UUUUU, 40 CFR part 63, list the EPA testing methods included in the final rule. Under section 63.7(f) and section 63.8(f) of subpart A of the General Provisions, a source may apply to the EPA for permission to use alternative test methods or alternative monitoring requirements in place of any of the EPA testing methods, performance specifications, or procedures specified.

J. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations

Executive Order 12898 (59 FR 7629; February 16, 1994) establishes federal executive policy on environmental justice (EJ). Its main provision directs federal agencies, to the greatest extent practicable and permitted by law, to make EJ part of their mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of their programs, policies, and activities on minority populations and low-income populations in the U.S.

The EPA has determined that this final rule will not have disproportionately high and adverse human health or environmental effects on minority, low income, and indigenous populations because it increases the level of environmental protection for all affected populations without having any disproportionately

high and adverse human health or environmental effects on any population, including any minority, low income, and indigenous populations.

This final rule establishes national emission standards for new and existing EGUs that combust coal and oil. The EPA estimates that there are approximately 1,400 units located at 600 facilities covered by this final rule.

This final rule will reduce emissions of all the listed HAP that come from EGUs. This includes metals (Hg, As, Be, Cd, Cr, Pb, Mn, Ni, and Se), organics (POM, acetaldehyde, acrolein, benzene, dioxins, ethylene dichloride, formaldehyde, and PCB), and acid gases (HCl and HF). At sufficient levels of exposure, these pollutants can cause a range of health effects including cancer; irritation of the lungs, skin, and mucous membranes; effects on the central nervous system such as memory and IQ loss and learning disabilities; damage to the kidneys; and other acute health disorders.

The final rule will also result in substantial reductions of criteria pollutants such as CO, PM, and SO_2. Sulfur dioxide is a precursor pollutant that is often transformed into fine PM ($PM_{2.5}$) in the atmosphere. Reducing direct emissions of $PM_{2.5}$ and SO_2 will, as a result, reduce concentrations of $PM_{2.5}$ in the atmosphere. These reductions in $PM_{2.5}$ will provide large health benefits, such as reducing the risk of premature mortality for adults, chronic and acute bronchitis, childhood asthma attacks, and hospitalizations for other respiratory and cardiovascular diseases. (For more details on the health effects of metals, organics, and $PM_{2.5}$, please refer to the RIA contained in the docket for this rulemaking.) This final rule will also have a small effect on electricity and natural gas prices but has the potential to affect the cost structure of the utility industry and could lead to shifts in how and where electricity is generated.

This final rule is one of a group of regulatory actions that the EPA has taken and will take over the next several years to respond to statutory and judicial mandates that will reduce exposure to HAP and $PM_{2.5}$, as well as to other pollutants, from EGUs and other sources. In addition, the EPA will pursue energy efficiency improvements throughout the economy, along with other federal agencies, states and other groups. This will contribute to additional environmental and public health improvements while lowering the costs of realizing those improvements. Together, these rules and actions will have substantial and long-term effects on both the U.S. power industry and on communities currently breathing dirty air. Therefore, we anticipate significant interest in many, if not most, of these actions from EJ communities, among many others.

1. Key EJ Aspects of the Rule

This is an air toxics rule; therefore, it does not permit emissions trading among sources. Instead, this final rule will place a limit on the rates of Hg and other HAP emitted from each affected EGU. As a result, emissions of Hg and other HAP such as HCl will be substantially reduced in the vast majority of states. In some states, however, there may be small increases in Hg and other HAP emissions due to shifts in electricity generation from EGUs with higher emission rates to EGUs with already low emission rates. Hydrogen chloride emissions are projected to increase at a small number of sources but that does not lead to any increased emissions at the state level.

The primary risk analysis to support the finding that this final rule is both appropriate and necessary includes an analysis of the effects of Hg from EGUs on people who rely on freshwater fish they catch as a regular and frequent part of their diet. These groups are characterized as subsistence level fishing populations or fishers. A significant portion of the data in this analysis came from published studies of EJ communities where people frequently consume locally-caught freshwater fish. These communities included: (1) White and black populations (including female and poor strata) surveyed in South Carolina; (2) Hispanic, Vietnamese and Laotian populations surveyed in California; and (3) Great Lakes tribal populations (Chippewa and Ojibwe) active on ceded territories around the Great Lakes. These data were used to help estimate risks to similar populations beyond the areas where the study data were collected. For example, while the Vietnamese and Laotian survey data were collected in California, given the ethnic (heritage) nature of these high fish consumption rates, we assumed that they could also be associated with members of these ethnic groups living elsewhere in the U.S. Therefore, the high-end consumption rates referenced in the California study for these ethnic groups were used to model risk at watersheds elsewhere in the U.S. As a result of this approach, the specific fish consumption patterns of several different EJ groups are fundamental to the EPA's assessment of both the underlying risks that make this final rule appropriate and necessary, and of the analysis of the benefits of reducing exposure to Hg and the other HAP.

The EPA's full analysis of risks from consumption of Hg-contaminated fish is contained in the RIA for this rule. The effects of this final rule on the health risks from Hg and other HAP are presented in the preamble and in the RIA for this rule.

2. Potential Environmental and Public Health Impacts to Minority, Low Income, or Tribal Populations

The EPA has conducted several analyses that provide additional insight on the potential effects of this rule on EJ communities. These include: (1) The socio-economic distribution of people living close to affected EGUs who may be exposed to pollution from these sources; and (2) an analysis of the distribution of health effects expected from the reductions in $PM_{2.5}$ that will result from implementation of this final rule (co-benefits).

a. Socio-Economic Distribution. As part of the analysis for this final rule, the EPA reviewed the aggregate demographic makeup of the communities near EGUs covered by this final rule. Although this analysis gives some indication of populations that may be exposed to levels of pollution that cause concern, it does not identify the demographic characteristics of the most highly affected individuals or communities. Electric generating units usually have very tall emission stacks; this tends to disperse the pollutants emitted from these stacks fairly far from the source. In addition, several of the pollutants emitted by these sources, such as a common form of Hg and SO_2, are known to travel long distances and contribute to adverse impacts on both the environment and human health hundreds or even thousands of miles from where they were emitted (in the case of elemental Hg, globally).

The proximity-to-the-source review is included in the analysis for this final rule because some EGUs emit enough HAP such as Ni or Cr(VI) to cause elevated lifetime cancer risks greater than 1 in a million in nearby communities. In addition, the EPA's analysis indicates that there are localized areas with potential for elevated levels of Hg deposition around most U.S. EGUs.[381]

The analysis of demographic data used proximity-to-the-source as a surrogate for exposure to identify those populations considered to be living near affected sources, such that they have notable exposures to current HAP

[381] See Excess Local Deposition TSD for more detail.

emissions from these sources. The demographic data for this analysis were extracted from the 2000 census data which were provided to the EPA by the U.S. Census Bureau. Distributions by race are based on demographic information at the census block level, and all other demographic groups are based on the extrapolation of census block group level data to the census block level. The socio-demographic parameters used in the analysis included the following categories: Racial (White, African American, Native American, Other or Multiracial, and All Other Races); Ethnicity (Hispanic); and Other (Number of people below the poverty line, Number of people with ages between 0 and 18, Number of people greater than or equal to 65, Number of people with no high school diploma).

In determining the aggregate demographic makeup of the communities near affected sources, the EPA focused on those census blocks within three miles of affected sources and determined the demographic composition (*e.g.*, race, income, etc.) of these census blocks and compared them to the corresponding compositions nationally. The radius of 3 miles (or approximately 5 kilometers) is consistent with other demographic analyses focused on areas around potential sources. In addition, air quality modeling experience has shown that the area within three miles of an individual source of emissions can generally be considered the area with the highest ambient air levels of the primary pollutants being emitted for most sources, both in absolute terms and relative to the contribution of other sources (assuming there are other sources in the area, as is typical in urban areas). Although facility processes and fugitive emissions may have more localized impacts, the EPA acknowledges that because of various stack heights there is the potential for dispersion beyond 3 miles. To the extent that any minority, low income, and indigenous subpopulation is disproportionately impacted by the current emissions as a result of the proximity of their homes to these sources, that subpopulation also stands to see increased environmental and health benefit from the emissions reductions called for by this rule. The results of the EPA's demographic analysis for affected sources are shown in the following table: [382] [383]

TABLE 12—COMPARATIVE SUMMARY OF THE DEMOGRAPHICS WITHIN 5 KM (3 MILES) OF THE AFFECTED SOURCES

[Population in millions] [382]

	White	African American	Native American	Other and multi-racial	Hispanic	Minority [383]	Below poverty line
Near Source Total (3 mi)	8.78	2.51	0.10	2.52	2.86	5.13	2.43
% of Near Source Total	63	18	1	18	21	37	17
National Total	215	35	2.49	33.3	39.1	70.8	37.1
% of National Total	75	12	1	12	14	25	13

[382] Racial and ethnic categories overlap and cannot be summed.
[383] The "Minority" population is the overall population (in the first row) minus white population (in the second row).

The data indicate that coal-fired EGUs are located in areas where the minority share of the population living within a three mile buffer is higher than the national average by 12 percentage points or 48 percent. For these same areas, the percent of the population below the poverty line is also higher than the national average by 4 percentage points or 31 percent. These results are presented in more detail in the "Review of Proximity Analysis," February 2011, a copy of which is available in the docket.

b. $PM_{2.5}$ (Co-Benefits) Analysis. As mentioned above, many of the steps EGUs will take to reduce their emissions of air toxics as required by this final rule will also reduce emissions of PM and SO_2. As a result, this final rule will reduce concentrations of $PM_{2.5}$ in the atmosphere. Exposure to $PM_{2.5}$ can cause or contribute to adverse health effects, such as asthma and heart disease, that significantly affect many minority, low-income, and tribal individuals and their communities. Fine PM ($PM_{2.5}$) is particularly (but not exclusively) harmful to children, the elderly, and people with existing heart and lung diseases, including asthma. Exposure can cause premature death and trigger heart attacks, asthma attacks in children and adults with asthma, chronic and acute bronchitis, and emergency room visits and hospitalizations, as well as milder illnesses that keep children home from school and adults home from work. Missing work due to illness or the illness of a child is a particular problem for people who have jobs that do not provide paid sick days. Low-wage employees also risk losing their jobs if they are absent too often, even if it is due to their own illness or the illness of a child or other relative. Finally, many individuals in these communities lack access to high quality health care to treat these types of illnesses. Due to all these factors, many minority and low-income communities are particularly susceptible to the health effects of $PM_{2.5}$ and receive a variety of benefits from reducing it.

We estimate that in 2016 the annual PM-related benefits of the final rule for adults include approximately 4,200 to 11,000 fewer premature mortalities, 2,900 fewer cases of chronic bronchitis, 4,800 fewer non-fatal heart attacks, 2,600 fewer hospitalizations (for respiratory and cardiovascular disease combined), 3.2 million fewer days of restricted activity due to respiratory illness and approximately 540,000 fewer lost work days. As described in EO 13045, Protection of Children from Environmental Health Risks and Safety Risks, we also estimate substantial health improvements for children.

We also examined the $PM_{2.5}$ mortality risks according to race, income, and educational attainment. We then estimated the change in $PM_{2.5}$ mortality risk as a result of this final rule among people living in the counties with the highest (top 5 percent) $PM_{2.5}$ mortality risk in 2005. We then compared the change in risk among the people living in these "high-risk" counties with people living in all other counties.

In 2005, people living in the highest risk counties and in the poorest counties had a substantially higher risk of $PM_{2.5}$-related death than people living in the other 95 percent of counties. This was

true regardless of race; the difference between the groups of counties for each race was large while the differences among races in both groups of counties was very small. In contrast, the analysis found that people with less than high school education had a significantly greater risk from $PM_{2.5}$ mortality than people with a greater than high school education. This was true both for the highest-risk counties and for the other counties. In summary, the analysis indicates that in 2005, educational status, living in one of the poorest counties, and living in a high-risk county are associated with higher $PM_{2.5}$ mortality risk while race is not.

Our analysis demonstrates that this final rule will significantly reduce the $PM_{2.5}$ mortality among all populations of different races living throughout the U.S. compared to both 2005 and 2016 pre-rule (*i.e.*, base case) levels. The analysis indicates that people living in counties with the highest rates (top 5 percent) of $PM_{2.5}$ mortality risk in 2005 receive the largest reduction in mortality risk after this rule takes effect. We also find that people living in the poorest 5 percent of the counties receive a larger reduction in $PM_{2.5}$ mortality risk than all other counties. More information can be found in Section 7.11 of the RIA.

The EPA estimates that the benefits of the final rule are distributed among races, income levels, and levels of education fairly evenly. However, the analysis does indicate that this final rule in conjunction with the implementation of existing or final rules (*e.g.*, the CSAPR) will reduce the disparity in risk between those in the highest-risk counties and the other 95 percent of counties for all races and educational levels. In addition, in many cases implementation of this final rule and other rules will, together, reduce risks in the highest-risk counties to the approximate level of risk for the rest of the counties as it existed before implementation of the rule.

These results are presented in more detail in Section 7.11 of the RIA.

3. Meaningful Public Participation

The EPA defines "environmental justice" to include meaningful involvement of all people regardless of race, color, national origin, or income with respect to the development, implementation, and enforcement of environmental laws, regulations, and policies. To promote meaningful involvement, the EPA publicized the rulemaking via newsletters, EJ listserves, and the internet, including the Office of Policy's (OP) Rulemaking Gateway Web site (*http://yosemite.epa.gov/opei/RuleGate.nsf/*). During the comment period, the EPA discussed the proposed rule via a conference call with communities, conducted a community-oriented webinar on the proposed rule, and posted the webinar presentation on-line. The EPA also held three public hearings to receive additional input on the proposal.

There will continue to be opportunities for public notice and comment as the utilities move forward with implementation of this rule. Once the rule is finalized, affected EGUs will need to update their Title V operating permits to reflect their new emission limits, any other new applicable requirements, and the associated monitoring and recordkeeping from this rule. The Title V permitting process provides that when most permits are reopened (for example, to incorporate new applicable requirements) or renewed, there must be opportunity for public review and comments. In addition, after the public review process, the EPA has an opportunity to review the proposed permit and object to its issuance if it does not meet CAA requirements.

4. Additional Analysis

In addition to the previously described assessment of EJ impacts, the EPA conducted an analysis of sub-populations with particularly high potential risks of Hg exposure due to high rates of fish consumption. These populations overlap in many cases with traditional EJ populations and would benefit from Hg reductions resulting from this rule. The EPA also conducted an analysis of the distribution of $PM_{2.5}$-related mortality risk according to the race, income and education of the population and how MATS changes this distribution. These analyses can be found in Section 7.12 of the RIA.

5. Summary

This final rule strictly limits the emissions rate of Hg and other HAP from every affected EGU. The EPA's analysis indicates substantial health benefits, including for minority, low income, and indigenous populations, from reductions in $PM_{2.5}$.

The EPA's analysis also indicates reductions in risks for individuals, including for members of minority populations, who eat fish frequently from U.S. lakes and rivers and who live near affected sources. Based on all the available information, the EPA has determined that this final rule will not have disproportionately high and adverse human health or environmental effects on minority, low income, and indigenous populations. The EPA is providing multiple opportunities for EJ communities to both learn about and comment on this rule and welcomes their participation as implementation of the rule proceeds.

K. Congressional Review Act

The Congressional Review Act, 5 U.S.C. 801 et seq., as added by the Small Business Regulatory Enforcement Fairness Act of 1996, generally provides that before a rule may take effect, the agency promulgating the rule must submit a rule report, which includes a copy of the rule, to each House of the Congress and to the Comptroller General of the U.S. The EPA will submit a report containing this rule and other required information to the U.S. Senate, the U.S. House of Representatives, and the Comptroller General of the U.S. prior to publication of the rule in the **Federal Register**. A major rule cannot take effect until 60 days after it is published in the **Federal Register**. This action is a "major rule" as defined by 5 U.S.C. 804(2). This rule will be effective April 16, 2012.

List of Subjects

40 CFR Part 60

Environmental protection, Administrative practice and procedure, Air pollution control, Incorporation by reference, Intergovernmental relations, Reporting and recordkeeping requirements.

40 CFR Part 63

Environmental protection, Administrative practice and procedure, Air pollution control, Hazardous substances, Incorporation by reference, Intergovernmental relations, Reporting and recordkeeping requirements.

Dated: December 16, 2011.

Lisa P. Jackson,

Administrator.

For the reasons stated in the preamble, title 40, chapter I, of the Code of the Federal Regulations is amended as follows:

PART 60—[AMENDED]

■ 1. The authority citation for part 60 continues to read as follows:

Authority: 42 U.S.C. 7401 *et seq.*

Subpart A—[Amended]

■ 2. Section 60.17 is amended:

■ a. By redesignating paragraph (a)(93), added March 21, 2011, at 76 FR 15750, and delayed indefinitely at 76 FR 28664, May 18, 2011, as paragraph (a)(96);

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■ b. By redesignating paragraphs (a)(91) and (a)(92) as paragraphs (a)(94) and (a)(95);
■ c. By redesignating paragraphs (a)(89) and (a)(90) as paragraphs (a)(91) and (a)(92);
■ d. By redesignating paragraphs (a)(54) through (a)(88) as paragraphs (a)(55) through (a)(89);
■ e. By adding paragraph (a)(54);
■ f. By adding paragraph (a)(90); and
■ g. By adding paragraph (a)(93) to read as follows:

§ 60.17 Incorporations by reference.

* * * * *

(a) * * *

(54) ASTM D3699–08, Standard Specification for Kerosine, including Appendix X1, approved September 1, 2008, IBR approved for §§ 60.41b of subpart Db of this part and 60.41c of subpart Dc of this part.

* * * * *

(90) ASTM D6751–11b, Standard Specification for Biodiesel Fuel Blend Stock (B100) for Middle Distillate Fuels, including Appendices X1 through X3, approved July 15, 2011, IBR approved for §§ 60.41b of subpart Db of this part and 60.41c of subpart Dc of this part.

* * * * *

(93) ASTM D7467–10, Standard Specification for Diesel Fuel Oil, Biodiesel Blend (B6 to B20), including Appendices X1 through X3, approved August 1, 2010, IBR approved for §§ 60.41b of subpart Db of this part and 60.41c of subpart Dc of this part.

* * * * *

Subpart B—[Amended]

■ 3. Section 60.21 is amended as follows:
■ a. By revising paragraph (a).
■ b. By revising paragraph (f).
■ c. By removing paragraph (k).

§ 60.21 Definitions.

* * * * *

(a) *Designated pollutant* means any air pollutant, the emissions of which are subject to a standard of performance for new stationary sources, but for which air quality criteria have not been issued and that is not included on a list published under section 108(a) or section 112(b)(1)(A) of the Act.

* * * * *

(f) *Emission standard* means a legally enforceable regulation setting forth an allowable rate of emissions into the atmosphere, establishing an allowance system, or prescribing equipment specifications for control of air pollution emissions.

* * * * *

■ 4. Section 60.24 is amended as follows:
■ a. By revising paragraph (b)(1).
■ b. By removing paragraph (h).

§ 60.24 Emission standards and compliance schedules.

* * * * *

(b) * * *

(1) Emission standards shall either be based on an allowance system or prescribe allowable rates of emissions except when it is clearly impracticable. Such cases will be identified in the guideline documents issued under § 60.22. Where emission standards prescribing equipment specifications are established, the plan shall, to the degree possible, set forth the emission reductions achievable by implementation of such specifications, and may permit compliance by the use of equipment determined by the State to be equivalent to that prescribed.

* * * * *

Subpart D—[Amended]

■ 5. The subpart heading for Subpart D is revised to read as follows:

Subpart D—Standards of Performance for Fossil-Fuel-Fired Steam Generators

■ 6. Section 60.40 is amended by revising paragraph (e) to read as follows:

§ 60.40 Applicability and designation of affected facility.

* * * * *

(e) Any facility subject to either subpart Da or KKKK of this part is not subject to this subpart.

■ 7. Section 60.41 is amended by adding the definition of "natural gas" in alphabetical order to read as follows:

§ 60.41 Definitions.

* * * * *

Natural gas means a fluid mixture of hydrocarbons (*e.g.*, methane, ethane, or propane), composed of at least 70 percent methane by volume or that has a gross calorific value between 35 and 41 megajoules (MJ) per dry standard cubic meter (950 and 1,100 Btu per dry standard cubic foot), that maintains a gaseous state under ISO conditions. In addition, *natural gas* contains 20.0 grains or less of total sulfur per 100 standard cubic feet. Finally, natural gas does not include the following gaseous fuels: landfill gas, digester gas, refinery gas, sour gas, blast furnace gas, coal-derived gas, producer gas, coke oven gas, or any gaseous fuel produced in a process which might result in highly variable sulfur content or heating value.

* * * * *

■ 8. Section 60.42 is amended as follows:
■ a. By revising paragraph (a) introductory text.
■ b. By adding paragraph (d).
■ c. By adding paragraph (e).

§ 60.42 Standard for particulate matter (PM).

(a) Except as provided under paragraphs (b), (c), (d), and (e) of this section, on and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases that:

* * * * *

(d) An owner or operator of an affected facility that combusts only natural gas is exempt from the PM and opacity standards specified in paragraph (a) of this section.

(e) An owner or operator of an affected facility that combusts only gaseous or liquid fossil fuel (excluding residual oil) with potential SO_2 emissions rates of 26 ng/J (0.060 lb/MMBtu) or less and that does not use post-combustion technology to reduce emissions of SO_2 or PM is exempt from the PM standards specified in paragraph (a) of this section.

■ 9. Section 60.45 is amended as follows:
■ a. By revising paragraph (a).
■ b. By revising paragraph (b) introductory text.
■ c. By revising paragraphs (b)(1) through (5).
■ d. By revising paragraph (b)(6) introductory text.
■ e. By revising paragraphs (b)(7)(i)(A) through (C).
■ f. By revising paragraph (b)(7)(ii)(B).
■ g. By adding paragraph (b)(8).

§ 60.45 Emissions and fuel monitoring.

(a) Each owner or operator of an affected facility subject to the applicable emissions standard shall install, calibrate, maintain, and operate continuous opacity monitoring system (COMS) for measuring opacity and a continuous emissions monitoring system (CEMS) for measuring SO_2 emissions, NO_X emissions, and either oxygen (O_2) or carbon dioxide (CO_2) except as provided in paragraph (b) of this section.

(b) Certain of the CEMS and COMS requirements under paragraph (a) of this section do not apply to owners or operators under the following conditions:

(1) For a fossil-fuel-fired steam generator that combusts only gaseous or liquid fossil fuel (excluding residual oil)

with potential SO_2 emissions rates of 26 ng/J (0.060 lb/MMBtu) or less and that does not use post-combustion technology to reduce emissions of SO_2 or PM, COMS for measuring the opacity of emissions and CEMS for measuring SO_2 emissions are not required if the owner or operator monitors SO_2 emissions by fuel sampling and analysis or fuel receipts.

(2) For a fossil-fuel-fired steam generator that does not use a flue gas desulfurization device, a CEMS for measuring SO_2 emissions is not required if the owner or operator monitors SO_2 emissions by fuel sampling and analysis.

(3) Notwithstanding § 60.13(b), installation of a CEMS for NO_X may be delayed until after the initial performance tests under § 60.8 have been conducted. If the owner or operator demonstrates during the performance test that emissions of NO_X are less than 70 percent of the applicable standards in § 60.44, a CEMS for measuring NO_X emissions is not required. If the initial performance test results show that NO_X emissions are greater than 70 percent of the applicable standard, the owner or operator shall install a CEMS for NO_X within one year after the date of the initial performance tests under § 60.8 and comply with all other applicable monitoring requirements under this part.

(4) If an owner or operator is not required to and elects not to install any CEMS for either SO_2 or NO_X, a CEMS for measuring either O_2 or CO_2 is not required.

(5) For affected facilities using a PM CEMS, a bag leak detection system to monitor the performance of a fabric filter (baghouse) according to the most current requirements in § 60.48Da of this part, or an ESP predictive model to monitor the performance of the ESP developed in accordance and operated according to the most current requirements in section § 60.48Da of this part a COMS is not required.

(6) A COMS for measuring the opacity of emissions is not required for an affected facility that does not use post-combustion technology (except a wet scrubber) for reducing PM, SO_2, or carbon monoxide (CO) emissions, burns only gaseous fuels or fuel oils that contain less than or equal to 0.30 weight percent sulfur, and is operated such that emissions of CO to the atmosphere from the affected source are maintained at levels less than or equal to 0.15 lb/MMBtu on a boiler operating day average basis. Owners and operators of affected sources electing to comply with this paragraph must demonstrate compliance according to the procedures specified in paragraphs (b)(6)(i) through (iv) of this section.

* * * * *

(7) * * *

(i) * * *

(A) If no visible emissions are observed, a subsequent Method 9 of appendix A–4 of this part performance test must be completed within 12 calendar months from the date that the most recent performance test was conducted or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later;

(B) If visible emissions are observed but the maximum 6-minute average opacity is less than or equal to 5 percent, a subsequent Method 9 of appendix A–4 of this part performance test must be completed within 6 calendar months from the date that the most recent performance test was conducted or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later;

(C) If the maximum 6-minute average opacity is greater than 5 percent but less than or equal to 10 percent, a subsequent Method 9 of appendix A–4 of this part performance test must be completed within 3 calendar months from the date that the most recent performance test was conducted or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later; or

* * * * *

(ii) * * *

(B) If no visible emissions are observed for 10 operating days during which an opacity standard is applicable, observations can be reduced to once every 7 operating days during which an opacity standard is applicable. If any visible emissions are observed, daily observations shall be resumed.

* * * * *

(8) A COMS for measuring the opacity of emissions is not required for an affected facility at which the owner or operator installs, calibrates, operates, and maintains a particulate matter continuous parametric monitoring system (PM CPMS) according to the requirements specified in subpart UUUUU of part 63.

* * * * *

Subpart Da—[Amended]

■ 10. The subpart heading for Subpart Da is revised to read as follows:

Subpart Da—Standards of Performance for Electric Utility Steam Generating Units

■ 11. Section 60.40Da is amended by revising paragraphs (b)(1) and (e) to read as follows:

§ 60.40Da Applicability and designation of affected facility.

* * * * *

(b) * * *

(1) The IGCC electric utility steam generating unit is capable of combusting more than 73 MW (250 MMBtu/h) heat input of fossil fuel (either alone or in combination with any other fuel) in the combustion turbine engine and associated heat recovery steam generator; and

* * * * *

(e) Applicability of this subpart to an electric utility combined cycle gas turbine other than an IGCC electric utility steam generating unit is as specified in paragraphs (e)(1) through (3) of this section.

(1) Affected facilities (*i.e.* heat recovery steam generators used with duct burners) associated with a stationary combustion turbine that are capable of combusting more than 73 MW (250 MMBtu/h) heat input of fossil fuel are subject to this subpart except in cases when the affected facility (*i.e.* heat recovery steam generator) meets the applicability requirements of and is subject to subpart KKKK of this part.

(2) For heat recovery steam generators use with duct burners subject to this subpart, only emissions resulting from the combustion of fuels in the steam generating unit (*i.e.* duct burners) are subject to the standards under this subpart. (The emissions resulting from the combustion of fuels in the stationary combustion turbine engine are subject to subpart GG or KKKK, as applicable, of this part.)

(3) Any affected facility that meets the applicability requirements and is subject to subpart Eb or subpart CCCC of this part is not subject to the emission standards under subpart Da.

■ 12. Section 60.41Da is amended as follows:

■ a. By revising the definitions of "boiler operating day", "gaseous fuel", "integrated gasification combined cycle electric utility steam generating unit", "natural gas", "petroleum", "potential combustion concentration", and "steam generating unit".

■ b. By adding the definitions of "affirmative defense", "combined heat and power", "gross energy output", "net energy output", "out-of-control period", and "petroleum coke" in alphabetical order.

■ c. By removing the definitions of "available purchase power", "cogeneration", "dry flue gas desulfurization technology ", "electric utility company", "emergency condition", "emission rate period", "gross output", "interconnected", "net system capacity", "principal company", "responsible official", "spare flue gas desulfurization system module", "spinning reserve", "system emergency reserves", and "system load".

§ 60.41Da Definitions.

* * * * *

Affirmative defense means, in the context of an enforcement proceeding, a response or defense put forward by a defendant, regarding which the defendant has the burden of proof, and the merits of which are independently and objectively evaluated in a judicial or administrative proceeding.

* * * * *

Boiler operating day for units constructed, reconstructed, or modified before February 29, 2005, means a 24-hour period during which fossil fuel is combusted in a steam-generating unit for the entire 24 hours. For units constructed, reconstructed, or modified after February 28, 2005, *boiler operating day* means a 24-hour period between 12 midnight and the following midnight during which any fuel is combusted at any time in the steam-generating unit. It is not necessary for fuel to be combusted the entire 24-hour period.

* * * * *

Combined heat and power, also known as "cogeneration," means a steam-generating unit that simultaneously produces both electric (and mechanical) and useful thermal energy from the same primary energy source.

* * * * *

Gaseous fuel means any fuel that is present as a gas at standard conditions and includes, but is not limited to, natural gas, refinery fuel gas, process gas, coke-oven gas, synthetic gas, and gasified coal.

* * * * *

Gross energy output means:

(1) For facilities constructed, reconstructed, or modified before May 4, 2011, the gross electrical or mechanical output from the affected facility plus 75 percent of the useful thermal output measured relative to ISO conditions that is not used to generate additional electrical or mechanical output or to enhance the performance of the unit (*i.e.,* steam delivered to an industrial process);

(2) For facilities constructed, reconstructed, or modified after May 3, 2011, the gross electrical or mechanical output from the affected facility minus any electricity used to power the feedwater pumps and any associated gas compressors (air separation unit main compressor, oxygen compressor, and nitrogen compressor) plus 75 percent of the useful thermal output measured relative to ISO conditions that is not used to generate additional electrical or mechanical output or to enhance the performance of the unit (*i.e.,* steam delivered to an industrial process);

(3) For combined heat and power facilities constructed, reconstructed, or modified after May 3, 2011, the gross electrical or mechanical output from the affected facility divided by 0.95 minus any electricity used to power the feedwater pumps and any associated gas compressors (air separation unit main compressor, oxygen compressor, and nitrogen compressor) plus 75 percent of the useful thermal output measured relative to ISO conditions that is not used to generate additional electrical or mechanical output or to enhance the performance of the unit (*i.e.,* steam delivered to an industrial process);

(4) For a IGCC electric utility generating unit that coproduces chemicals constructed, reconstructed, or modified after May 3, 2011, the gross useful work performed is the gross electrical or mechanical output from the unit minus electricity used to power the feedwater pumps and any associated gas compressors (air separation unit main compressor, oxygen compressor, and nitrogen compressor) that are associated with power production plus 75 percent of the useful thermal output measured relative to ISO conditions that is not used to generate additional electrical or mechanical output or to enhance the performance of the unit (*i.e.,* steam delivered to an industrial process). Auxiliary loads that are associated with power production are determined based on the energy in the coproduced chemicals compared to the energy of the syngas combusted in combustion turbine engine and associated duct burners.

* * * * *

Integrated gasification combined cycle electric utility steam generating unit or *IGCC electric utility steam generating unit* means an electric utility combined cycle gas turbine that is designed to burn fuels containing 50 percent (by heat input) or more solid-derived fuel not meeting the definition of natural gas. The Administrator may waive the 50 percent solid-derived fuel requirement during periods of the gasification system construction or repair. No solid fuel is directly burned in the unit during operation.

* * * * *

Natural gas means a fluid mixture of hydrocarbons (*e.g.,* methane, ethane, or propane), composed of at least 70 percent methane by volume or that has a gross calorific value between 35 and 41 megajoules (MJ) per dry standard cubic meter (950 and 1,100 Btu per dry standard cubic foot), that maintains a gaseous state under ISO conditions. In addition, *natural gas* contains 20.0 grains or less of total sulfur per 100 standard cubic feet. Finally, natural gas does not include the following gaseous fuels: landfill gas, digester gas, refinery gas, sour gas, blast furnace gas, coal-derived gas, producer gas, coke oven gas, or any gaseous fuel produced in a process which might result in highly variable sulfur content or heating value.

Net energy output means the gross energy output minus the parasitic load associated with power production. Parasitic load includes, but is not limited to, the power required to operate the equipment used for fuel delivery systems, air pollution control systems, wastewater treatment systems, ash handling and disposal systems, and other controls (*i.e.,* pumps, fans, compressors, motors, instrumentation, and other ancillary equipment required to operate the affected facility).

* * * * *

Out-of-control period means any period beginning with the quadrant corresponding to the completion of a daily calibration error, linearity check, or quality assurance audit that indicates that the instrument is not measuring and recording within the applicable performance specifications and ending with the quadrant corresponding to the completion of an additional calibration error, linearity check, or quality assurance audit following corrective action that demonstrates that the instrument is measuring and recording within the applicable performance specifications.

Petroleum for facilities constructed, reconstructed, or modified before May 4, 2011, means crude oil or a fuel derived from crude oil, including, but not limited to, distillate oil, and residual oil. For units constructed, reconstructed, or modified after May 3, 2011, *petroleum* means crude oil or a fuel derived from crude oil, including, but not limited to, distillate oil, residual oil, and petroleum coke.

Petroleum coke, also known as "petcoke," means a carbonization product of high-boiling hydrocarbon fractions obtained in petroleum processing (heavy residues). *Petroleum*

coke is typically derived from oil refinery coker units or other cracking processes.

Potential combustion concentration means the theoretical emissions (nanograms per joule (ng/J), lb/MMBtu heat input) that would result from combustion of a fuel in an uncleaned state without emission control systems. For sulfur dioxide (SO_2) the potential combustion concentration is determined under § 60.50Da(c).

* * * * *

Steam generating unit for facilities constructed, reconstructed, or modified before May 4, 2011, means any furnace, boiler, or other device used for combusting fuel for the purpose of producing steam (including fossil-fuel-fired steam generators associated with combined cycle gas turbines; nuclear steam generators are not included). For units constructed, reconstructed, or modified after May 3, 2011, *steam generating unit* means any furnace, boiler, or other device used for combusting fuel for the purpose of producing steam (including fossil-fuel-fired steam generators associated with combined cycle gas turbines; nuclear steam generators are not included) plus any integrated combustion turbines and fuel cells.

* * * * *

■ 13. Section 60.42Da is revised to read as follows:

§ 60.42Da Standards for particulate matter (PM).

(a) Except as provided in paragraph (f) of this section, on and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, an owner or operator of an affected facility shall not cause to be discharged into the atmosphere from any affected facility for which construction, reconstruction, or modification commenced before March 1, 2005, any gases that contain PM in excess of 13 ng/J (0.030 lb/MMBtu) heat input.

(b) Except as provided in paragraphs (b)(1) and (b)(2) of this section, on and after the date the initial PM performance test is completed or required to be completed under § 60.8, whichever date comes first, an owner or operator of an affected facility shall not cause to be discharged into the atmosphere any gases which exhibit greater than 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity.

(1) An owner or operator of an affected facility that elects to install, calibrate, maintain, and operate a continuous emissions monitoring system (CEMS) for measuring PM emissions according to the requirements of this subpart is exempt from the opacity standard specified in this paragraph (b) of this section.

(2) An owner or operator of an affected facility that combusts only natural gas is exempt from the opacity standard specified in paragraph (b) of this section.

(c) Except as provided in paragraphs (d) and (f) of this section, on and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification after February 28, 2005, but before May 4, 2011, shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of either:

(1) 18 ng/J (0.14 lb/MWh) gross energy output; or

(2) 6.4 ng/J (0.015 lb/MMBtu) heat input derived from the combustion of solid, liquid, or gaseous fuel.

(d) As an alternative to meeting the requirements of paragraph (c) of this section, the owner or operator of an affected facility for which construction, reconstruction, or modification commenced after February 28, 2005, but before May 4, 2011, may elect to meet the requirements of this paragraph. On and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of:

(1) 13 ng/J (0.030 lb/MMBtu) heat input derived from the combustion of solid, liquid, or gaseous fuel, and

(2) For an affected facility that commenced construction or reconstruction, 0.1 percent of the combustion concentration determined according to the procedure in § 60.48Da(o)(5) (99.9 percent reduction) when combusting solid, liquid, or gaseous fuel, or

(3) For an affected facility that commenced modification, 0.2 percent of the combustion concentration determined according to the procedure in § 60.48Da(o)(5) (99.8 percent reduction) when combusting solid, liquid, or gaseous fuel.

(e) Except as provided in paragraph (f) of this section, the owner or operator of an affected facility that commenced construction, reconstruction, or modification commenced after May 3, 2011, shall meet the requirements specified in paragraphs (e)(1) and (2) of this section.

(1) On and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator shall cause to be discharged into the atmosphere from that affected facility at all times except during periods of startup and shutdown, any gases that contain PM in excess of the applicable emissions limit specified in paragraphs (e)(1)(i) or (ii) of this section.

(i) For an affected facility which commenced construction or reconstruction, any gases that contain PM in excess of either:

(A) 11 ng/J (0.090 lb/MWh) gross energy output; or

(B) 12 ng/J (0.097 lb/MWh) net energy output.

(ii) For an affected facility which commenced modification, any gases that contain PM in excess of 13 ng/J (0.015 lb/MMBtu) heat input.

(2) During periods of startup and shutdown, the owner or operator shall meet the work practice standards specified in Table 3 to subpart UUUUU of part 63.

(f) An owner or operator of an affected facility that meets the conditions in either paragraphs (f)(1) or (2) of this section is exempt from the PM emissions limits in this section.

(1) The affected facility combusts only gaseous or liquid fuels (excluding residual oil) with potential SO_2 emissions rates of 26 ng/J (0.060 lb/MMBtu) or less, and that does not use a post-combustion technology to reduce emissions of SO_2 or PM.

(2) The affected facility is operated under a PM commercial demonstration permit issued by the Administrator according to the provisions of § 60.47Da.

■ 14. Section 60.43Da is amended as follows:

■ a. The section heading is revised.

■ b. By revising paragraphs (a)(1) and (2).

■ c. By adding paragraphs (a)(3) and (4).

■ d. By removing and reserving paragraph (c).

■ e. By revising paragraph (f).

■ f. By revising paragraph (i).

■ g. By revising paragraph (k).

■ h. By adding paragraph (l).

■ i. By adding paragraph (m).

§ 60.43Da Standards for sulfur dioxide (SO_2).

(a) * * *

(1) 520 ng/J (1.20 lb/MMBtu) heat input and 10 percent of the potential combustion concentration (90 percent reduction);

(2) 30 percent of the potential combustion concentration (70 percent

reduction), when emissions are less than 260 ng/J (0.60 lb/MMBtu) heat input;

(3) 180 ng/J (1.4 lb/MWh) gross energy output; or

(4) 65 ng/J (0.15 lb/MMBtu) heat input.

* * * * *

(f) The SO_2 standards under this section do not apply to an owner or operator of an affected facility that is operated under an SO_2 commercial demonstration permit issued by the Administrator in accordance with the provisions of § 60.47Da.

* * * * *

(i) Except as provided in paragraphs (j) and (k) of this section, on and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility for which construction, reconstruction, or modification commenced after February 28, 2005, but before May 4, 2011, shall cause to be discharged into the atmosphere from that affected facility, any gases that contain SO_2 in excess of the applicable emissions limit specified in paragraphs (i)(1) through (3) of this section.

(1) For an affected facility which commenced construction, any gases that contain SO_2 in excess of either:

(i) 180 ng/J (1.4 lb/MWh) gross energy output; or

(ii) 5 percent of the potential combustion concentration (95 percent reduction).

(2) For an affected facility which commenced reconstruction, any gases that contain SO_2 in excess of either:

(i) 180 ng/J (1.4 lb/MWh) gross energy output;

(ii) 65 ng/J (0.15 lb/MMBtu) heat input; or

(iii) 5 percent of the potential combustion concentration (95 percent reduction).

(3) For an affected facility which commenced modification, any gases that contain SO_2 in excess of either:

(i) 180 ng/J (1.4 lb/MWh) gross energy output;

(ii) 65 ng/J (0.15 lb/MMBtu) heat input; or

(iii) 10 percent of the potential combustion concentration (90 percent reduction).

* * * * *

(k) On and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility located in a noncontinental area for which construction, reconstruction, or modification commenced after February 28, 2005, but before May 4, 2011, shall cause to be discharged into the atmosphere from that affected facility any gases that contain SO_2 in excess of the applicable emissions limit specified in paragraphs (k)(1) and (2) of this section.

(1) For an affected facility that burns solid or solid-derived fuel, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain SO_2 in excess of 520 ng/J (1.2 lb/MMBtu) heat input.

(2) For an affected facility that burns other than solid or solid-derived fuel, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain SO_2 in excess of 230 ng/J (0.54 lb/MMBtu) heat input.

(l) Except as provided in paragraphs (j) and (m) of this section, on and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility for which construction, reconstruction, or modification commenced after May 3, 2011, shall cause to be discharged into the atmosphere from that affected facility, any gases that contain SO_2 in excess of the applicable emissions limit specified in paragraphs (l)(1) and (2) of this section.

(1) For an affected facility which commenced construction or reconstruction, any gases that contain SO_2 in excess of either:

(i) 130 ng/J (1.0 lb/MWh) gross energy output; or

(ii) 140 ng/J (1.2 lb/MWh) net energy output; or

(iii) 3 percent of the potential combustion concentration (97 percent reduction).

(2) For an affected facility which commenced modification, any gases that contain SO_2 in excess of either:

(i) 180 ng/J (1.4 lb/MWh) gross energy output; or

(ii) 10 percent of the potential combustion concentration (90 percent reduction).

(m) On and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility located in a noncontinental area for which construction, reconstruction, or modification commenced after May 3, 2011, shall cause to be discharged into the atmosphere from that affected facility any gases that contain SO_2 in excess of the applicable emissions limit specified in paragraphs (m)(1) and (2) of this section.

(1) For an affected facility that burns solid or solid-derived fuel, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain SO_2 in excess of 520 ng/J (1.2 lb/MMBtu) heat input.

(2) For an affected facility that burns other than solid or solid-derived fuel, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain SO_2 in excess of 230 ng/J (0.54 lb/MMBtu) heat input.

■ 15. Section 60.44Da is revised to read as follows:

§ 60.44Da Standards for nitrogen oxides (NO_X).

(a) Except as provided in paragraph (h) of this section, on and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility for which construction, reconstruction, or modification commenced before July 10, 1997 any gases that contain NO_X (expressed as NO_2) in excess of the applicable emissions limit in paragraphs (a)(1) and (2) of this section.

(1) The owner or operator shall not cause to be discharged into the atmosphere any gases that contain NO_X in excess of the emissions limit listed in the following table as applicable to the fuel type combusted and as determined on a 30-boiler operating day rolling average basis.

Fuel type	Emission limit for heat input	
	ng/J	lb/MMBtu
Gaseous fuels:		
Coal-derived fuels	210	0.50
All other fuels	86	0.20
Liquid fuels:		

Fuel type	Emission limit for heat input	
	ng/J	lb/MMBtu
Coal-derived fuels	210	0.50
Shale oil	210	0.50
All other fuels	130	0.30
Solid fuels:		
Coal-derived fuels	210	0.50
Any fuel containing more than 25%, by weight, coal refuse	(1)	(1)
Any fuel containing more than 25%, by weight, lignite if the lignite is mined in North Dakota, South Dakota, or Montana, and is combusted in a slag tap furnace [2]	340	0.80
Any fuel containing more than 25%, by weight, lignite not subject to the 340 ng/J heat input emission limit [2]	260	0.60
Subbituminous coal	210	0.50
Bituminous coal	260	0.60
Anthracite coal	260	0.60
All other fuels	260	0.60

[1] Exempt from NO_X standards and NO_X monitoring requirements.
[2] Any fuel containing less than 25%, by weight, lignite is not prorated but its percentage is added to the percentage of the predominant fuel.

(2) When two or more fuels are combusted simultaneously in an affected facility, the applicable emissions limit (E_n) is determined by proration using the following formula:

$$En = \frac{(86w + 130x + 210y + 260z + 340v)}{100}$$

Where:

En = Applicable NO_X emissions limit when multiple fuels are combusted simultaneously (ng/J heat input);
w = Percentage of total heat input derived from the combustion of fuels subject to the 86 ng/J heat input standard;
x = Percentage of total heat input derived from the combustion of fuels subject to the 130 ng/J heat input standard;
y = Percentage of total heat input derived from the combustion of fuels subject to the 210 ng/J heat input standard;
z = Percentage of total heat input derived from the combustion of fuels subject to the 260 ng/J heat input standard; and
v = Percentage of total heat input delivered from the combustion of fuels subject to the 340 ng/J heat input standard.

(b) [Reserved]

(c) [Reserved]

(d) Except as provided in paragraph (h) of this section, on and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification after July 9, 1997, but before March 1, 2005, shall cause to be discharged into the atmosphere from that affected facility any gases that contain NO_X (expressed as NO_2) in excess of the applicable emissions limit specified in paragraphs (d)(1) and (2) of this section as determined on a 30-boiler operating day rolling average basis.

(1) For an affected facility which commenced construction, any gases that contain NO_X in excess of 200 ng/J (1.6 lb/MWh) gross energy output.

(2) For an affected facility which commenced reconstruction, any gases that contain NO_X in excess of 65 ng/J (0.15 lb/MMBtu) heat input.

(e) Except as provided in paragraphs (f) and (h) of this section, on and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification after February 28, 2005 but before May 4, 2011, shall cause to be discharged into the atmosphere from that affected facility any gases that contain NO_X (expressed as NO_2) in excess of the applicable emissions limit specified in paragraphs (e)(1) through (3) of this section as determined on a 30-boiler operating day rolling average basis.

(1) For an affected facility which commenced construction, any gases that contain NO_X in excess of 130 ng/J (1.0 lb/MWh) gross energy output.

(2) For an affected facility which commenced reconstruction, any gases that contain NO_X in excess of either:

(i) 130 ng/J (1.0 lb/MWh) gross energy output; or

(ii) 47 ng/J (0.11 lb/MMBtu) heat input.

(3) For an affected facility which commenced modification, any gases that contain NO_X in excess of either:

(i) 180 ng/J (1.4 lb/MWh) gross energy output; or

(ii) 65 ng/J (0.15 lb/MMBtu) heat input.

(f) On and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, the owner or operator of an IGCC electric utility steam generating unit subject to the provisions of this subpart and for which construction, reconstruction, or modification commenced after February 28, 2005 but before May 4, 2011, shall meet the requirements specified in paragraphs (f)(1) through (3) of this section.

(1) Except as provided for in paragraphs (f)(2) and (3) of this section, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain NO_X (expressed as NO_2) in excess of 130 ng/J (1.0 lb/MWh) gross energy output.

(2) When burning liquid fuel exclusively or in combination with solid-derived fuel such that the liquid fuel contributes 50 percent or more of the total heat input to the combined cycle combustion turbine, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain NO_X (expressed as NO_2) in excess of 190 ng/J (1.5 lb/MWh) gross energy output.

(3) In cases when during a 30-boiler operating day rolling average compliance period liquid fuel is burned in such a manner to meet the conditions in paragraph (f)(2) of this section for only a portion of the clock hours in the

30-day compliance period, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain NO_X (expressed as NO_2) in excess of the computed weighted-average emissions limit based on the proportion of gross energy output (in MWh) generated during the compliance period for each of emissions limits in paragraphs (f)(1) and (2) of this section.

(g) Except as provided in paragraphs (h) of this section and § 60.45Da, on and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification after May 3, 2011, shall cause to be discharged into the atmosphere from that affected facility any gases that contain NO_X (expressed as NO_2) in excess of the applicable emissions limit specified in paragraphs (g)(1) through (3) of this section.

(1) For an affected facility which commenced construction or reconstruction, any gases that contain NO_X in excess of either:

(i) 88 ng/J (0.70 lb/MWh) gross energy output; or

(ii) 95 ng/J (0.76 lb/MWh) net energy output.

(2) For an affected facility which commenced construction or reconstruction and that burns 75 percent or more coal refuse (by heat input) on a 12-month rolling average basis, any gases that contain NO_X in excess of either:

(i) 110 ng/J (0.85 lb/MWh) gross energy output; or

(ii) 120 ng/J (0.92 lb/MWh) net energy output.

(3) For an affected facility which commenced modification, any gases that contain NO_X in excess of 140 ng/J (1.1 lb/MWh) gross energy output.

(h) The NO_X emissions limits under this section do not apply to an owner or operator of an affected facility which is operating under a commercial demonstration permit issued by the Administrator in accordance with the provisions of § 60.47Da.

■ 16. Section 60.45Da is revised to read as follows:

§ 60.45Da Alternative standards for combined nitrogen oxides (NO_X) and carbon monoxide (CO).

(a) The owner or operator of an affected facility that commenced construction, reconstruction, or modification after May 3, 2011 as alternate to meeting the applicable NO_X emissions limits specified in § 60.44Da may elect to meet the applicable standards for combined NO_X and CO specified in paragraph (b) of this section.

(b) On and after the date on which the initial performance test is completed or required to be completed under § 60.8 no owner or operator of an affected facility that commenced construction, reconstruction, or modification after May 3, 2011, shall cause to be discharged into the atmosphere from that affected facility any gases that contain NO_X (expressed as NO_2) plus CO in excess of the applicable emissions limit specified in paragraphs (b)(1) through (3) of this section as determined on a 30-boiler operating day rolling average basis.

(1) For an affected facility which commenced construction or reconstruction, any gases that contain NO_X plus CO in excess of either:

(i) 140 ng/J (1.1 lb/MWh) gross energy output; or

(ii) 150 ng/J (1.2 lb/MWh) net energy output.

(2) For an affected facility which commenced construction or reconstruction and that burns 75 percent or more coal refuse (by heat input) on a 12-month rolling average basis, any gases that contain NO_X plus CO in excess of either:

(i) 160 ng/J (1.3 lb/MWh) gross energy output; or

(ii) 170 ng/J (1.4 lb/MWh) net energy output.

(3) For an affected facility which commenced modification, any gases that contain NO_X plus CO in excess of 190 ng/J (1.5 lb/MWh) gross energy output.

■ 17. Section 60.47Da is amended as follows:

■ a. By revising paragraph (c).
■ b. By adding paragraph (f).
■ c. By adding paragraph (g).
■ d. By adding paragraph (h).
■ e. By adding paragraph (i).

§ 60.47Da Commercial demonstration permit.

* * * * *

(c) An owner or operator of an affected facility that uses fluidized bed combustion (atmospheric or pressurized) and who is issued a commercial demonstration permit by the Administrator is not subject to the SO_2 emission reduction requirements under § 60.43Da(a) but must, as a minimum, reduce SO_2 emissions to 15 percent of the potential combustion concentration (85 percent reduction) on a 30-day rolling average basis and to less than 520 ng/J (1.20 lb/MMBtu) heat input on a 30-day rolling average basis.

* * * * *

(f) An owner or operator of an affected facility that uses a pressurized fluidized bed or a multi-pollutant emissions controls system who is issued a commercial demonstration permit by the Administrator is not subject to the total PM emission reduction requirements under § 60.42Da but must, as a minimum, reduce PM emissions to less than 6.4 ng/J (0.015 lb/MMBtu) heat input.

(g) An owner or operator of an affected facility that uses a pressurized fluidized bed or a multi-pollutant emissions controls system who is issued a commercial demonstration permit by the Administrator is not subject to the SO_2 standards or emission reduction requirements under § 60.43Da but must, as a minimum, reduce SO_2 emissions to 5 percent of the potential combustion concentration (95 percent reduction) or to less than 180 ng/J (1.4 lb/MWh) gross energy output on a 30-boiler operating day rolling average basis.

(h) An owner or operator of an affected facility that uses a pressurized fluidized bed or a multi-pollutant emissions control system or advanced combustion controls who is issued a commercial demonstration permit by the Administrator is not subject to the NO_X standards or emission reduction requirements under § 60.44Da but must, as a minimum, reduce NO_X emissions to less than 130 ng/J (1.0 lb/MWh) or the combined NO_X plus CO emissions to less than 180 ng/J (1.4 lb/MWh) gross energy output on a 30-boiler operating day rolling average basis.

(i) Commercial demonstration permits may not exceed the following equivalent MW electrical generation capacity for any one technology category listed in the following table.

Technology	Pollutant	Equivalent electrical capacity (MW electrical output)
Multi-pollutant Emission Control	SO_2	1,000

Technology	Pollutant	Equivalent electrical capacity (MW electrical output)
Multi-pollutant Emission Control	NO_X	1,000
Multi-pollutant Emission Control	PM	1,000
Pressurized Fluidized Bed Combustion	SO_2	1,000
Pressurized Fluidized Bed Combustion	NO_X	1,000
Pressurized Fluidized Bed Combustion	PM	1,000
Advanced Combustion Controls	NO_X	1,000

■ 18. Section 60.48Da is amended as follows:
■ a. By revising paragraphs (a) through (g).
■ b. By revising paragraph (i).
■ c. By revising paragraph (k)(1)(i).
■ d. By revising paragraph (k)(2)(i).
■ e. By revising paragraph (k)(2)(iv).
■ f. By removing and reserving paragraph (l).
■ g. By revising paragraph (m).
■ h. By revising paragraph (n).
■ i. By revising paragraphs (p)(5), (7), and (8).
■ j. By adding paragraph (r).
■ k. By adding paragraph (s).

§ 60.48Da Compliance provisions.

(a) For affected facilities for which construction, modification, or reconstruction commenced before May 4, 2011, the applicable PM emissions limit and opacity standard under § 60.42Da, SO_2 emissions limit under § 60.43Da, and NO_X emissions limit under § 60.44Da apply at all times except during periods of startup, shutdown, or malfunction. For affected facilities for which construction, modification, or reconstruction commenced after May 3, 2011, the applicable SO_2 emissions limit under § 60.43Da, NO_X emissions limit under § 60.44Da, and NO_X plus CO emissions limit under § 60.45Da apply at all times. The applicable PM emissions limit and opacity standard under § 60.42Da apply at all times except during periods of startup and shutdown.

(b) After the initial performance test required under § 60.8, compliance with the applicable SO_2 emissions limit and percentage reduction requirements under § 60.43Da, NO_X emissions limit under § 60.44Da, and NO_X plus CO emissions limit under § 60.45Da is based on the average emission rate for 30 successive boiler operating days. A separate performance test is completed at the end of each boiler operating day after the initial performance test, and a new 30-boiler operating day rolling average emission rate for both SO_2, NO_X or NO_X plus CO as applicable, and a new percent reduction for SO_2 are calculated to demonstrate compliance with the standards.

(c) For the initial performance test required under § 60.8, compliance with the applicable SO_2 emissions limits and percentage reduction requirements under § 60.43Da, the NO_X emissions limits under § 60.44Da, and the NO_X plus CO emissions limits under § 60.45Da is based on the average emission rates for SO_2, NO_X, CO, and percent reduction for SO_2 for the first 30 successive boiler operating days. The initial performance test is the only test in which at least 30 days prior notice is required unless otherwise specified by the Administrator. The initial performance test is to be scheduled so that the first boiler operating day of the 30 successive boiler operating days is completed within 60 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of the facility.

(d) For affected facilities for which construction, modification, or reconstruction commenced before May 4, 2011, compliance with applicable 30-boiler operating day rolling average SO_2 and NO_X emissions limits is determined by calculating the arithmetic average of all hourly emission rates for SO_2 and NO_X for the 30 successive boiler operating days, except for data obtained during startup, shutdown, or malfunction. For affected facilities for which construction, modification, or reconstruction commenced after May 3, 2011, compliance with applicable 30-boiler operating day rolling average SO_2 and NO_X emissions limits is determined by dividing the sum of the SO_2 and NO_X emissions for the 30 successive boiler operating days by the sum of the gross energy output or net energy output, as applicable, for the 30 successive boiler operating days.

(e) For affected facilities for which construction, modification, or reconstruction commenced before May 4, 2011, compliance with applicable SO_2 percentage reduction requirements is determined based on the average inlet and outlet SO_2 emission rates for the 30 successive boiler operating days. For affected facilities for which construction, modification, or reconstruction commenced after May 3, 2011, compliance with applicable SO_2 percentage reduction requirements is determined based on the "as fired" total potential emissions and the total outlet SO_2 emissions for the 30 successive boiler operating days.

(f) For affected facilities for which construction, modification, or reconstruction commenced before May 4, 2011, compliance with applicable daily average PM emissions limits is determined by calculating the arithmetic average of all hourly emission rates for PM each boiler operating day, except for data obtained during startup, shutdown, and malfunction. Daily averages are only calculated for boiler operating days that have non-out-of-control data for at least 18 hours of unit operation during which the standard applies. Instead, all of the non-out-of-control hourly emission rates of the operating day(s) not meeting the minimum 18 hours non-out-of-control data daily average requirement are averaged with all of the non-out-of-control hourly emission rates of the next boiler operating day with 18 hours or more of non-out-of-control PM CEMS data to determine compliance. For affected facilities for which construction, modification, or reconstruction commenced after May 3, 2011, compliance with applicable daily average PM emissions limits is determined by dividing the sum of the PM emissions for the 30 successive boiler operating days by the sum of the gross useful output or net energy output, as applicable, for the 30 successive boiler operating days.

(g) For affected facilities for which construction, modification, or reconstruction commenced after May 3, 2011, compliance with applicable 30-boiler operating day rolling average NO_X plus CO emissions limit is determined by dividing the sum of the NO_X plus CO emissions for the 30 successive boiler operating days by the sum of the gross energy output or net energy output, as

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applicable, for the 30 successive boiler operating days.

* * * * *

(i) Compliance provisions for sources subject to § 60.44Da(d)(1), (e)(1), (e)(2)(i), (e)(3)(i), (f), or (g). The owner or operator shall calculate NO_X emissions as 1.194×10^{-7} lb/scf-ppm times the average hourly NO_X output concentration in ppm (measured according to the provisions of § 60.49Da(c)), times the average hourly flow rate (measured in scfh, according to the provisions of § 60.49Da(l) or § 60.49Da(m)), divided by the average hourly gross energy output (measured according to the provisions of § 60.49Da(k)) or the average hourly net energy output, as applicable. Alternatively, for oil-fired and gas-fired units, NO_X emissions may be calculated by multiplying the hourly NO_X emission rate in lb/MMBtu (measured by the CEMS required under § 60.49Da(c) and (d)), by the hourly heat input rate (measured according to the provisions of § 60.49Da(n)), and dividing the result by the average gross energy output (measured according to the provisions of § 60.49Da(k)) or the average hourly net energy output, as applicable.

(k) * * *

(1) * * *

(i) The emission rate (E) of NO_X shall be computed using Equation 2 in this section:

$$E = \frac{(Csg \times Qsg) - (Cte \times Qte)}{(Osg \times h)} \quad \text{(Eq. 2)}$$

Where:

E = Emission rate of NO_X from the duct burner, ng/J (lb/MWh) gross energy output;

C_{sg} = Average hourly concentration of NO_X exiting the steam generating unit, ng/dscm (lb/dscf);

C_{te} = Average hourly concentration of NO_X in the turbine exhaust upstream from duct burner, ng/dscm (lb/dscf);

Q_{sg} = Average hourly volumetric flow rate of exhaust gas from steam generating unit, dscm/h (dscf/h);

Q_{te} = Average hourly volumetric flow rate of exhaust gas from combustion turbine, dscm/h (dscf/h);

O_{sg} = Average hourly gross energy output from steam generating unit, J/h (MW); and

h = Average hourly fraction of the total heat input to the steam generating unit derived from the combustion of fuel in the affected duct burner.

* * * * *

(2) * * *

(i) The emission rate (E) of NO_X shall be computed using Equation 3 in this section:

$$E = \frac{(Csg \times Qsg)}{Occ} \quad \text{(Eq. 3)}$$

Where:

E = Emission rate of NO_X from the duct burner, ng/J (lb/MWh) gross energy output;

C_{sg} = Average hourly concentration of NO_X exiting the steam generating unit, ng/dscm (lb/dscf);

Q_{sg} = Average hourly volumetric flow rate of exhaust gas from steam generating unit, dscm/h (dscf/h); and

O_{cc} = Average hourly gross energy output from entire combined cycle unit, J/h (MW).

* * * * *

(iv) The owner or operator may, in lieu of installing, operating, and recording data from the continuous flow monitoring system specified in § 60.49Da(l), determine the mass rate (lb/h) of NO_X emissions by installing, operating, and maintaining continuous fuel flowmeters following the appropriate measurements procedures specified in appendix D of part 75 of this chapter. If this compliance option is selected, the emission rate (E) of NO_X shall be computed using Equation 4 in this section:

$$E = \frac{(ERsg \times Hcc)}{Occ} \quad \text{(Eq. 4)}$$

Where:

E = Emission rate of NO_X from the duct burner, ng/J (lb/MWh) gross energy output;

ER_{sg} = Average hourly emission rate of NO_X exiting the steam generating unit heat input calculated using appropriate F factor as described in Method 19 of appendix A of this part, ng/J (lb/MMBtu);

H_{cc} = Average hourly heat input rate of entire combined cycle unit, J/h (MMBtu/h); and

O_{cc} = Average hourly gross energy output from entire combined cycle unit, J/h (MW).

* * * * *

(m) Compliance provisions for sources subject to § 60.43Da(i)(1)(i), (i)(2)(i), (i)(3)(i), (j)(1)(i), (j)(2)(i), (j)(3)(i), (l)(1)(i), (l)(1)(ii), or (l)(2). The owner or operator shall calculate SO_2 emissions as 1.660×10^{-7} lb/scf-ppm times the average hourly SO_2 output concentration in ppm (measured according to the provisions of § 60.49Da(b)), times the average hourly flow rate (measured according to the provisions of § 60.49Da(l) or § 60.49Da(m)), divided by the average hourly gross energy output (measured according to the provisions of § 60.49Da(k)) or the average hourly net energy output, as applicable. Alternatively, for oil-fired and gas-fired units, SO_2 emissions may be calculated by multiplying the hourly SO_2 emission rate (in lb/MMBtu), measured by the CEMS required under § 60.49Da, by the hourly heat input rate (measured according to the provisions of § 60.49Da(n)), and dividing the result by the average gross energy output (measured according to the provisions of § 60.49Da(k)) or the average hourly net energy output, as applicable.

(n) Compliance provisions for sources subject to § 60.42Da(c)(1) or (e)(1)(i). The owner or operator shall calculate PM emissions by multiplying the average hourly PM output concentration (measured according to the provisions of § 60.49Da(t)), by the average hourly flow rate (measured according to the provisions of § 60.49Da(l) or § 60.49Da(m)), and dividing by the average hourly gross energy output (measured according to the provisions

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of § 60.49Da(k)) or the average hourly net energy output, as applicable.

* * * * *

(p) * * *

(5) At a minimum, non-out-of-control CEMS hourly averages shall be obtained for 75 percent of all operating hours on a 30-boiler operating day rolling average basis. Beginning on January 1, 2012, non-out-of-control CEMS hourly averages shall be obtained for 90 percent of all operating hours on a 30-boiler operating day rolling average basis.

(i) At least two data points per hour shall be used to calculate each 1-hour arithmetic average.

(ii) [Reserved]

* * * * *

(7) All non-out-of-control CEMS data shall be used in calculating average emission concentrations even if the minimum CEMS data requirements of paragraph (j)(5) of this section are not met.

(8) When PM emissions data are not obtained because of CEMS breakdowns, repairs, calibration checks, and zero and span adjustments, emissions data shall be obtained by using other monitoring systems as approved by the Administrator or EPA Reference Method 19 of appendix A of this part to provide, as necessary, non-out-of-control emissions data for a minimum of 90 percent (only 75 percent is required prior to January 1, 2012) of all operating hours per 30-boiler operating day rolling average.

* * * * *

(r) Compliance provisions for sources subject to § 60.45Da. To determine compliance with the NO_X plus CO emissions limit, the owner or operator shall use the procedures specified in paragraphs (r)(1) through (3) of this section.

(1) Calculate NO_X emissions as 1.194×10^{-7} lb/scf-ppm times the average hourly NO_X output concentration in ppm (measured according to the provisions of § 60.49Da(c)), times the average hourly flow rate (measured in scfh, according to the provisions of § 60.49Da(l) or § 60.49Da(m)), divided by the average hourly gross energy output (measured according to the provisions of § 60.49Da(k)) or the average hourly net energy output, as applicable.

(2) Calculate CO emissions by multiplying the average hourly CO output concentration (measured according to the provisions of § 60.49Da(u), by the average hourly flow rate (measured according to the provisions of § 60.49Da(l) or § 60.49Da(m)), and dividing by the average hourly gross energy output (measured according to the provisions of § 60.49Da(k)) or the average hourly net energy output, as applicable.

(3) Calculate NO_X plus CO emissions by summing the NO_X emissions results from paragraph (r)(1) of this section plus the CO emissions results from paragraph (r)(2) of this section.

(s) Affirmative defense for exceedance of emissions limit during malfunction. In response to an action to enforce the standards set forth in paragraph §§ 60.42Da, 60.43Da, 60.44Da, and 60.45Da, you may assert an affirmative defense to a claim for civil penalties for exceedances of such standards that are caused by malfunction, as defined at 40 CFR 60.2. Appropriate penalties may be assessed, however, if you fail to meet your burden of proving all of the requirements in the affirmative defense as specified in paragraphs (s)(1) and (2) of this section. The affirmative defense shall not be available for claims for injunctive relief.

(1) To establish the affirmative defense in any action to enforce such a limit, you must timely meet the notification requirements in paragraph (s)(2) of this section, and must prove by a preponderance of evidence that:

(i) The excess emissions:

(A) Were caused by a sudden, infrequent, and unavoidable failure of air pollution control and monitoring equipment, process equipment, or a process to operate in a normal or usual manner; and

(B) Could not have been prevented through careful planning, proper design, or better operation and maintenance practices; and

(C) Did not stem from any activity or event that could have been foreseen and avoided, or planned for; and

(D) Were not part of a recurring pattern indicative of inadequate design, operation, or maintenance; and

(ii) Repairs were made as expeditiously as possible when the applicable emissions limits were being exceeded. Off-shift and overtime labor were used, to the extent practicable to make these repairs; and

(iii) The frequency, amount, and duration of the excess emissions (including any bypass) were minimized to the maximum extent practicable during periods of such emissions; and

(iv) If the excess emissions resulted from a bypass of control equipment or a process, then the bypass was unavoidable to prevent loss of life, personal injury, or severe property damage; and

(v) All possible steps were taken to minimize the impact of the excess emissions on ambient air quality, the environment, and human health; and

(vi) All emissions monitoring and control systems were kept in operation if at all possible, consistent with safety and good air pollution control practices; and

(vii) All of the actions in response to the excess emissions were documented by properly signed, contemporaneous operating logs; and

(viii) At all times, the facility was operated in a manner consistent with good practices for minimizing emissions; and

(ix) A written root cause analysis has been prepared, the purpose of which is to determine, correct, and eliminate the primary causes of the malfunction and the excess emissions resulting from the malfunction event at issue. The analysis shall also specify, using best monitoring methods and engineering judgment, the amount of excess emissions that were the result of the malfunction.

(2) *Notification.* The owner or operator of the affected source experiencing an exceedance of its emission limit(s) during a malfunction shall notify the Administrator by telephone or facsimile (FAX) transmission as soon as possible, but no later than two business days after the initial occurrence of the malfunction or, if it is not possible to determine within two business days whether the malfunction caused or contributed to an exceedance, no later than two business days after the owner or operator knew or should have known that the malfunction caused or contributed to an exceedance, but, in no event later than two business days after the end of the averaging period, if it wishes to avail itself of an affirmative defense to civil penalties for that malfunction. The owner or operator seeking to assert an affirmative defense shall also submit a written report to the Administrator within 45 days of the initial occurrence of the exceedance of the standard in § 63.9991 to demonstrate, with all necessary supporting documentation, that it has met the requirements set forth in paragraph (s)(1) of this section. The owner or operator may seek an extension of this deadline for up to 30 additional days by submitting a written request to the Administrator before the expiration of the 45 day period. Until a request for an extension has been approved by the Administrator, the owner or operator is subject to the requirement to submit such report within 45 days of the initial occurrence of the exceedance.

■ 19. Section 60.49Da is amended as follows:

■ a. By revising paragraphs (a)(1) and (2).

■ b. By revising paragraph (a)(3) introductory text.
■ c. By revising paragraph (a)(3)(ii).
■ d. By revising paragraph (a)(3)(iii)(B).
■ e. By adding paragraph (a)(4).
■ f. By revising paragraph (b) introductory text.
■ g. By revising paragraph (b)(2).
■ h. By revising paragraph (e).
■ i. By revising paragraph (k) introductory text.
■ j. By revising paragraph (k)(3).
■ k. By revising paragraph (l).
■ l. By removing and reserving paragraph (p).
■ m. By removing and reserving paragraph (q).
■ n. By removing and reserving paragraph (r).
■ o. By revising paragraph (t).
■ p. By revising paragraph (u)(1)(iii).
■ q. By revising paragraph (v)(4).

§ 60.49Da Emission monitoring.

(a) * * *

(1) Except as provided for in paragraphs (a)(2) and (4) of this section, the owner or operator of an affected facility subject to an opacity standard, shall install, calibrate, maintain, and operate a COMS, and record the output of the system, for measuring the opacity of emissions discharged to the atmosphere. If opacity interference due to water droplets exists in the stack (for example, from the use of an FGD system), the opacity is monitored upstream of the interference (at the inlet to the FGD system). If opacity interference is experienced at all locations (both at the inlet and outlet of the SO_2 control system), alternate parameters indicative of the PM control system's performance and/or good combustion are monitored (subject to the approval of the Administrator).

(2) As an alternative to the monitoring requirements in paragraph (a)(1) of this section, an owner or operator of an affected facility that meets the conditions in either paragraph (a)(2)(i), (ii), (iii), or (iv) of this section may elect to monitor opacity as specified in paragraph (a)(3) of this section.

(i) The affected facility uses a fabric filter (baghouse) to meet the standards in § 60.42Da and a bag leak detection system is installed and operated according to the requirements in paragraphs § 60.48Da(o)(4)(i) through (v);

(ii) The affected facility burns only gaseous or liquid fuels (excluding residual oil) with potential SO_2 emissions rates of 26 ng/J (0.060 lb/MMBtu) or less, and does not use a post-combustion technology to reduce emissions of SO_2 or PM;

(iii) The affected facility meets all of the conditions specified in paragraphs (a)(2)(iii)(A) through (C) of this section.

(A) No post-combustion technology (except a wet scrubber) is used for reducing PM, SO_2, or CO emissions;

(B) Only natural gas, gaseous fuels, or fuel oils that contain less than or equal to 0.30 weight percent sulfur are burned; and

(C) Emissions of CO discharged to the atmosphere are maintained at levels less than or equal to 1.4 lb/MWh on a boiler operating day average basis as demonstrated by the use of a CEMS measuring CO emissions according to the procedures specified in paragraph (u) of this section; or

(iv) The affected facility uses an ESP and uses an ESP predictive model to monitor the performance of the ESP developed in accordance and operated according to the most current requirements in section § 60.48Da of this part.

(3) The owner or operator of an affected facility that meets the conditions in paragraph (a)(2) of this section may, as an alternative to using a COMS, elect to monitor visible emissions using the applicable procedures specified in paragraphs (a)(3)(i) through (iv) of this section. The opacity performance test requirement in paragraph (a)(3)(i) must be conducted by April 29, 2011, within 45 days after stopping use of an existing COMS, or within 180 days after initial startup of the facility, whichever is later.

* * * * *

(ii) Except as provided in paragraph (a)(3)(iii) or (iv) of this section, the owner or operator shall conduct subsequent Method 9 of appendix A–4 of this part performance tests using the procedures in paragraph (a)(3)(i) of this section according to the applicable schedule in paragraphs (a)(3)(ii)(A) through (a)(3)(ii)(C) of this section, as determined by the most recent Method 9 of appendix A–4 of this part performance test results.

(A) If the maximum 6-minute average opacity is less than or equal to 5 percent, a subsequent Method 9 of appendix A–4 of this part performance test must be completed within 12 calendar months from the date that the most recent performance test was conducted or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later;

(B) If the maximum 6-minute average opacity is greater than 5 percent but less than or equal to 10 percent, a subsequent Method 9 of appendix A–4 of this part performance test must be completed within 3 calendar months from the date that the most recent performance test was conducted or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later; or

(C) If the maximum 6-minute average opacity is greater than 10 percent, a subsequent Method 9 of appendix A–4 of this part performance test must be completed within 45 calendar days from the date that the most recent performance test was conducted.

(iii) * * *

(B) If no visible emissions are observed for 10 operating days during which an opacity standard is applicable, observations can be reduced to once every 7 operating days during which an opacity standard is applicable. If any visible emissions are observed, daily observations shall be resumed.

* * * * *

(4) An owner or operator of an affected facility that is subject to an opacity standard under § 60.42a(b) is not required to operate a COMS provided that affected facility meets the conditions in either paragraph (a)(4)(i) or (ii) of this section.

(i) The affected facility combusts only gaseous fuels and/or liquid fuels (excluding residue oil) with a potential SO_2 emissions rate no greater than 26 ng/J (0.060 lb/MMBtu), and the unit operates according to a written site-specific monitoring plan approved by the permitting authority. This monitoring plan must include procedures and criteria for establishing and monitoring specific parameters for the affected facility indicative of compliance with the opacity standard. For testing performed as part of this site-specific monitoring plan, the permitting authority may require as an alternative to the notification and reporting requirements specified in §§ 60.8 and 60.11 that the owner or operator submit any deviations with the excess emissions report required under § 60.51a(d).

(ii) The owner or operator of the affected facility installs, calibrates, operates, and maintains a particulate matter continuous parametric monitoring system (PM CPMS) according to the requirements specified in subpart UUUUU of part 63.

(b) The owner or operator of an affected facility shall install, calibrate, maintain, and operate a CEMS, and record the output of the system, for measuring SO_2 emissions, except where natural gas and/or liquid fuels (excluding residual oil) with potential SO_2 emissions rates of 26 ng/J (0.060 lb/

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MMBtu) or less are the only fuels combusted, as follows:

* * * * *

(2) For a facility that qualifies under the numerical limit provisions of § 60.43Da, SO_2 emissions are only monitored as discharged to the atmosphere.

* * * * *

(e) The CEMS under paragraphs (b), (c), and (d) of this section are operated and data recorded during all periods of operation of the affected facility including periods of startup, shutdown, and malfunction, except for CEMS breakdowns, repairs, calibration checks, and zero and span adjustments.

* * * * *

(k) The procedures specified in paragraphs (k)(1) through (3) of this section shall be used to determine gross energy output for sources demonstrating compliance with an output-based standard.

* * * * *

(3) For an affected facility generating process steam in combination with electrical generation, the gross energy output is determined according to the definition of "gross energy output" specified in § 60.41Da that is applicable to the affected facility.

(l) The owner or operator of an affected facility demonstrating compliance with an output-based standard shall install, certify, operate, and maintain a continuous flow monitoring system meeting the requirements of Performance Specification 6 of appendix B of this part and the calibration drift (CD) assessment, relative accuracy test audit (RATA), and reporting provisions of procedure 1 of appendix F of this part, and record the output of the system, for measuring the volumetric flow rate of exhaust gases discharged to the atmosphere; or

* * * * *

(t) The owner or operator of an affected facility demonstrating compliance with the output-based emissions limitation under § 60.42Da shall install, certify, operate, and maintain a CEMS for measuring PM emissions according to the requirements of paragraph (v) of this section. An owner or operator of an affected facility demonstrating compliance with the input-based emissions limit in § 60.42Da may install, certify, operate, and maintain a CEMS for measuring PM emissions according to the requirements of paragraph (v) of this section.

(u) * * *

(1) * * *

(iii) At a minimum, non-out-of-control 1-hour CO emissions averages must be obtained for at least 90 percent of the operating hours on a 30-boiler operating day rolling average basis. The 1-hour averages are calculated using the data points required in § 60.13(h)(2).

* * * * *

(v) * * *

(4) As of January 1, 2012, and within 90 days after the date of completing each performance test, as defined in § 60.8, conducted to demonstrate compliance with this subpart, you must submit relative accuracy test audit (*i.e.,* reference method) data and performance test (*i.e.,* compliance test) data, except opacity data, electronically to EPA's Central Data Exchange (CDX) by using the Electronic Reporting Tool (ERT) (see *http://www.epa.gov/ttn/chief/ert/ert tool.html/*) or other compatible electronic spreadsheet. Only data collected using test methods compatible with ERT are subject to this requirement to be submitted electronically into EPA's WebFire database.

* * * * *

■ 20. Section 60.50Da is amended as follows:

■ a. By revising paragraph (b).

■ b. By removing paragraph (g).

■ c. By removing paragraph (h).

■ d. By removing paragraph (i).

§ 60.50Da Compliance determination procedures and methods.

* * * * *

(b) In conducting the performance tests to determine compliance with the PM emissions limits in § 60.42Da, the owner or operator shall meet the requirements specified in paragraphs (b)(1) through (3) of this section.

(1) The owner or operator shall measure filterable PM to determine compliance with the applicable PM emissions limit in § 60.42Da as specified in paragraphs (b)(1)(i) through (ii) of this section.

(i) The dry basis F factor (O_2) procedures in Method 19 of appendix A of this part shall be used to compute the emission rate of PM.

(ii) For the PM concentration, Method 5 of appendix A of this part shall be used for an affected facility that does not use a wet FGD. For an affected facility that uses a wet FGD, Method 5B of appendix A of this part shall be used downstream of the wet FGD.

(A) The sampling time and sample volume for each run shall be at least 120 minutes and 1.70 dscm (60 dscf). The probe and filter holder heating system in the sampling train may be set to provide an average gas temperature of no greater than 160 ± 14 °C (320 ± 25 °F).

(B) For each particulate run, the emission rate correction factor, integrated or grab sampling and analysis procedures of Method 3B of appendix A of this part shall be used to determine the O_2 concentration. The O_2 sample shall be obtained simultaneously with, and at the same traverse points as, the particulate run. If the particulate run has more than 12 traverse points, the O_2 traverse points may be reduced to 12 provided that Method 1 of appendix A of this part is used to locate the 12 O_2 traverse points. If the grab sampling procedure is used, the O_2 concentration for the run shall be the arithmetic mean of the sample O_2 concentrations at all traverse points.

(2) In conjunction with a performance test performed according to the requirements in paragraph (b)(1) of this section, the owner or operator of an affected facility for which construction, reconstruction, or modification commenced after May 3, 2011, shall measure condensable PM using Method 202 of appendix M of part 51.

(3) Method 9 of appendix A of this part and the procedures in § 60.11 shall be used to determine opacity.

* * * * *

■ 21. Section 60.51Da is amended as follows:

■ a. By revising paragraph (a).

■ b. By revising paragraph (b)(5).

■ c. By revising paragraph (d).

■ d. By removing and reserving paragraph (g).

■ e. By revising paragraph (k).

§ 60.51Da Reporting requirements.

(a) For SO_2, NO_X, PM, and NO_X plus CO emissions, the performance test data from the initial and subsequent performance test and from the performance evaluation of the continuous monitors (including the transmissometer) must be reported to the Administrator.

(b) * * *

(5) Identification of the times when emissions data have been excluded from the calculation of average emission rates because of startup, shutdown, or malfunction.

* * * * *

(d) In addition to the applicable requirements in § 60.7, the owner or operator of an affected facility subject to the opacity limits in § 60.43c(c) and conducting performance tests using Method 9 of appendix A–4 of this part shall submit excess emission reports for any excess emissions from the affected facility that occur during the reporting period and maintain records according to the requirements specified in paragraph (d)(1) of this section.

(1) For each performance test conducted using Method 9 of appendix

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A–4 of this part, the owner or operator shall keep the records including the information specified in paragraphs (d)(1)(i) through (iii) of this section.

(i) Dates and time intervals of all opacity observation periods;

(ii) Name, affiliation, and copy of current visible emission reading certification for each visible emission observer participating in the performance test; and

(iii) Copies of all visible emission observer opacity field data sheets.

(2) [Reserved]

* * * * *

(k) The owner or operator of an affected facility may submit electronic quarterly reports for SO_2 and/or NO_X and/or opacity in lieu of submitting the written reports required under paragraphs (b) and (i) of this section. The format of each quarterly electronic report shall be coordinated with the permitting authority. The electronic report(s) shall be submitted no later than 30 days after the end of the calendar quarter and shall be accompanied by a certification statement from the owner or operator, indicating whether compliance with the applicable emission standards and minimum data requirements of this subpart was achieved during the reporting period.

§ 60.52Da [Amended]

■ 22. Section 60.52Da is amended by removing and reserving paragraph (a).

Subpart Db—[Amended]

■ 23. Section 60.40b is amended as follows:

■ a. By revising paragraph (c).

■ b. By revising paragraph (h).

■ c. By revising paragraph (i).

■ d. By adding paragraph (l).

■ e. By adding paragraph (m).

§ 60.40b Applicability and delegation of authority.

* * * * *

(c) Affected facilities that also meet the applicability requirements under subpart J or subpart Ja of this part are subject to the PM and NO_X standards under this subpart and the SO_2 standards under subpart J or subpart Ja of this part, as applicable.

* * * * *

(h) Any affected facility that meets the applicability requirements and is subject to subpart Ea, subpart Eb, subpart AAAA, or subpart CCCC of this part is not subject to this subpart.

(i) Affected facilities (*i.e.*, heat recovery steam generators) that are associated with stationary combustion turbines and that meet the applicability requirements of subpart KKKK of this part are not subject to this subpart. This subpart will continue to apply to all other affected facilities (*i.e.* heat recovery steam generators with duct burners) that are capable of combusting more than 29 MW (100 MMBtu/h) heat input of fossil fuel. If the affected facility (*i.e.* heat recovery steam generator) is subject to this subpart, only emissions resulting from combustion of fuels in the steam generating unit are subject to this subpart. (The stationary combustion turbine emissions are subject to subpart GG or KKKK, as applicable, of this part.)

* * * * *

(l) Affected facilities that also meet the applicability requirements under subpart BB of this part (Standards of Performance for Kraft Pulp Mills) are subject to the SO_2 and NO_X standards under this subpart and the PM standards under subpart BB.

(m) Temporary boilers are not subject to this subpart.

24. Section 60.41b is amended by revising the definition of "distillate oil", and adding the definition of "temporary boiler" in alphabetical order to read as follows:

§ 60.41b Definitions.

* * * * *

Distillate oil means fuel oils that contain 0.05 weight percent nitrogen or less and comply with the specifications for fuel oil numbers 1 and 2, as defined by the American Society of Testing and Materials in ASTM D396 (incorporated by reference, see § 60.17), diesel fuel oil numbers 1 and 2, as defined by the American Society for Testing and Materials in ASTM D975 (incorporated by reference, see § 60.17), kerosine, as defined by the American Society of Testing and Materials in ASTM D3699 (incorporated by reference, see § 60.17), biodiesel as defined by the American Society of Testing and Materials in ASTM D6751 (incorporated by reference, see § 60.17), or biodiesel blends as defined by the American Society of Testing and Materials in ASTM D7467 (incorporated by reference, see § 60.17).

* * * * *

Temporary boiler means any gaseous or liquid fuel-fired steam generating unit that is designed to, and is capable of, being carried or moved from one location to another by means of, for example, wheels, skids, carrying handles, dollies, trailers, or platforms. A steam generating unit is not a temporary boiler if any one of the following conditions exists:

(1) The equipment is attached to a foundation.

(2) The steam generating unit or a replacement remains at a location for more than 180 consecutive days. Any temporary boiler that replaces a temporary boiler at a location and performs the same or similar function will be included in calculating the consecutive time period.

(3) The equipment is located at a seasonal facility and operates during the full annual operating period of the seasonal facility, remains at the facility for at least 2 years, and operates at that facility for at least 3 months each year.

(4) The equipment is moved from one location to another in an attempt to circumvent the residence time requirements of this definition.

* * * * *

■ 25. Section 60.43b is amended by revising paragraph (f) to read as follows:

§ 60.43b Standard for particulate matter (PM).

* * * * *

(f) On and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that combusts coal, oil, wood, or mixtures of these fuels with any other fuels shall cause to be discharged into the atmosphere any gases that exhibit greater than 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity. An owner or operator of an affected facility that elects to install, calibrate, maintain, and operate a continuous emissions monitoring system (CEMS) for measuring PM emissions according to the requirements of this subpart and is subject to a federally enforceable PM limit of 0.030 lb/MMBtu or less is exempt from the opacity standard specified in this paragraph.

* * * * *

■ 26. Section 60.44b is amended as follows:

■ a. The section heading is revised.

■ b. By revising paragraph (b) introductory text.

■ c. By revising paragraph (c).

■ d. By revising paragraph (d).

■ e. By revising paragraph (e).

■ f. By revising paragraph (l)(1).

§ 60.44b Standard for nitrogen oxides (NO_X).

* * * * *

(b) Except as provided under paragraphs (k) and (l) of this section, on and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that

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simultaneously combusts mixtures of only coal, oil, or natural gas shall cause to be discharged into the atmosphere from that affected facility any gases that contain NO_X in excess of a limit determined by the use of the following formula:

* * * * *

(c) Except as provided under paragraph (d) and (l) of this section, on and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that simultaneously combusts coal or oil, natural gas (or any combination of the three), and wood, or any other fuel shall cause to be discharged into the atmosphere any gases that contain NO_X in excess of the emission limit for the coal, oil, natural gas (or any combination of the three), combusted in the affected facility, as determined pursuant to paragraph (a) or (b) of this section. This standard does not apply to an affected facility that is subject to and in compliance with a federally enforceable requirement that limits operation of the affected facility to an annual capacity factor of 10 percent (0.10) or less for coal, oil, natural gas (or any combination of the three).

(d) On and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that simultaneously combusts natural gas and/or distillate oil with a potential SO_2 emissions rate of 26 ng/J (0.060 lb/MMBtu) or less with wood, municipal-type solid waste, or other solid fuel, except coal, shall cause to be discharged into the atmosphere from that affected facility any gases that contain NO_X in excess of 130 ng/J (0.30 lb/MMBtu) heat input unless the affected facility has an annual capacity factor for natural gas, distillate oil, or a mixture of these fuels of 10 percent (0.10) or less and is subject to a federally enforceable requirement that limits operation of the affected facility to an annual capacity factor of 10 percent (0.10) or less for natural gas, distillate oil, or a mixture of these fuels.

(e) Except as provided under paragraph (l) of this section, on and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that simultaneously combusts only coal, oil, or natural gas with byproduct/waste shall cause to be discharged into the atmosphere any gases that contain NO_X in excess of the emission limit determined by the following formula unless the affected facility has an annual capacity factor for coal, oil, and natural gas of 10 percent (0.10) or less and is subject to a federally enforceable requirement that limits operation of the affected facility to an annual capacity factor of 10 percent (0.10) or less:

* * * * *

(l) * * *

(1) 86 ng/J (0.20 lb/MMBtu) heat input if the affected facility combusts coal, oil, or natural gas (or any combination of the three), alone or with any other fuels. The affected facility is not subject to this limit if it is subject to and in compliance with a federally enforceable requirement that limits operation of the facility to an annual capacity factor of 10 percent (0.10) or less for coal, oil, and natural gas (or any combination of the three); or

* * * * *

■ 27. Section 60.46b is amended by revising paragraph (j)(14) to read as follows:

§ 60.46b Compliance and performance test methods and procedures for particulate matter and nitrogen oxides.

* * * * *

(j) * * *

(14) As of January 1, 2012, and within 90 days after the date of completing each performance test, as defined in § 60.8, conducted to demonstrate compliance with this subpart, you must submit relative accuracy test audit (*i.e.,* reference method) data and performance test (*i.e.,* compliance test) data, except opacity data, electronically to EPA's Central Data Exchange (CDX) by using the Electronic Reporting Tool (ERT) (see *http://www.epa.gov/ttn/chief/ert/ert_tool.html/*) or other compatible electronic spreadsheet. Only data collected using test methods compatible with ERT are subject to this requirement to be submitted electronically into EPA's WebFIRE database.

■ 28. Section 60.48b is amended as follows:

■ a. By revising paragraph (a) introductory text.

■ b. By revising paragraphs (a)(1)(i) through (iii) .

■ c. By revising paragraph (a)(2)(ii).

■ d. By revising paragraph (j) introductory text.

■ e. By revising paragraph (j)(5).

■ f. By revising paragraph (j)(6).

■ g. By adding paragraph (j)(7).

■ h. By adding paragraph (l).

§ 60.48b Emission monitoring for particulate matter and nitrogen oxides.

(a) Except as provided in paragraph (j) of this section, the owner or operator of an affected facility subject to the opacity standard under § 60.43b shall install, calibrate, maintain, and operate a continuous opacity monitoring systems (COMS) for measuring the opacity of emissions discharged to the atmosphere and record the output of the system. The owner or operator of an affected facility subject to an opacity standard under § 60.43b and meeting the conditions under paragraphs (j)(1), (2), (3), (4), (5), or (6) of this section who elects not to use a COMS shall conduct a performance test using Method 9 of appendix A–4 of this part and the procedures in § 60.11 to demonstrate compliance with the applicable limit in § 60.43b by April 29, 2011, within 45 days of stopping use of an existing COMS, or within 180 days after initial startup of the facility, whichever is later, and shall comply with either paragraphs (a)(1), (a)(2), or (a)(3) of this section. The observation period for Method 9 of appendix A–4 of this part performance tests may be reduced from 3 hours to 60 minutes if all 6-minute averages are less than 10 percent and all individual 15-second observations are less than or equal to 20 percent during the initial 60 minutes of observation.

(1) * * *

(i) If no visible emissions are observed, a subsequent Method 9 of appendix A–4 of this part performance test must be completed within 12 calendar months from the date that the most recent performance test was conducted or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later;

(ii) If visible emissions are observed but the maximum 6-minute average opacity is less than or equal to 5 percent, a subsequent Method 9 of appendix A–4 of this part performance test must be completed within 6 calendar months from the date that the most recent performance test was conducted or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later;

(iii) If the maximum 6-minute average opacity is greater than 5 percent but less than or equal to 10 percent, a subsequent Method 9 of appendix A–4 of this part performance test must be completed within 3 calendar months from the date that the most recent performance test was conducted or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later; or

* * * * *

(2) * * *

(ii) If no visible emissions are observed for 10 operating days during which an opacity standard is applicable, observations can be reduced to once every 7 operating days during which an

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opacity standard is applicable. If any visible emissions are observed, daily observations shall be resumed.

* * * * *

(j) The owner or operator of an affected facility that meets the conditions in either paragraph (j)(1), (2), (3), (4), (5), (6), or (7) of this section is not required to install or operate a COMS if:

* * * * *

(5) The affected facility uses a bag leak detection system to monitor the performance of a fabric filter (baghouse) according to the most current requirements in section § 60.48Da of this part; or

(6) The affected facility uses an ESP as the primary PM control device and uses an ESP predictive model to monitor the performance of the ESP developed in accordance and operated according to the most current requirements in section § 60.48Da of this part; or

(7) The affected facility burns only gaseous fuels or fuel oils that contain less than or equal to 0.30 weight percent sulfur and operates according to a written site-specific monitoring plan approved by the permitting authority. This monitoring plan must include procedures and criteria for establishing and monitoring specific parameters for the affected facility indicative of compliance with the opacity standard.

* * * * *

(l) An owner or operator of an affected facility that is subject to an opacity standard under § 60.43b(f) is not required to operate a COMS provided that the unit burns only gaseous fuels and/or liquid fuels (excluding residue oil) with a potential SO_2 emissions rate no greater than 26 ng/J (0.060 lb/MMBtu), and the unit operates according to a written site-specific monitoring plan approved by the permitting authority is not required to operate a COMS. This monitoring plan must include procedures and criteria for establishing and monitoring specific parameters for the affected facility indicative of compliance with the opacity standard. For testing performed as part of this site-specific monitoring plan, the permitting authority may require as an alternative to the notification and reporting requirements specified in §§ 60.8 and 60.11 that the owner or operator submit any deviations with the excess emissions report required under § 60.49b(h).

■ 29. Section 60.49b is amended by revising paragraph (r)(1) to read as follows.

§ 60.49b Reporting and recordkeeping requirements.

* * * * *

(r) * * *

(1) The owner or operator of an affected facility who elects to demonstrate that the affected facility combusts only very low sulfur oil, natural gas, wood, a mixture of these fuels, or any of these fuels (or a mixture of these fuels) in combination with other fuels that are known to contain an insignificant amount of sulfur in § 60.42b(j) or § 60.42b(k) shall obtain and maintain at the affected facility fuel receipts (such as a current, valid purchase contract, tariff sheet, or transportation contract) from the fuel supplier that certify that the oil meets the definition of distillate oil and gaseous fuel meets the definition of natural gas as defined in § 60.41b and the applicable sulfur limit. For the purposes of this section, the distillate oil need not meet the fuel nitrogen content specification in the definition of distillate oil. Reports shall be submitted to the Administrator certifying that only very low sulfur oil meeting this definition, natural gas, wood, and/or other fuels that are known to contain insignificant amounts of sulfur were combusted in the affected facility during the reporting period; or

* * * * *

Subpart Dc—[Amended]

■ 30. Section 60.40c is amended as follows:

■ a. By revising paragraph (a).
■ b. By revising paragraph (e).
■ c. By revising paragraph (f).
■ d. By revising paragraph (g).
■ e. By adding paragraph (h).
■ f. By adding paragraph (i).

§ 60.40c Applicability and delegation of authority.

(a) Except as provided in paragraphs (d), (e), (f), and (g) of this section, the affected facility to which this subpart applies is each steam generating unit for which construction, modification, or reconstruction is commenced after June 9, 1989 and that has a maximum design heat input capacity of 29 megawatts (MW) (100 million British thermal units per hour (MMBtu/h)) or less, but greater than or equal to 2.9 MW (10 MMBtu/h).

* * * * *

(e) Affected facilities (*i.e.* heat recovery steam generators and fuel heaters) that are associated with stationary combustion turbines and meet the applicability requirements of subpart KKKK of this part are not subject to this subpart. This subpart will continue to apply to all other heat recovery steam generators, fuel heaters, and other affected facilities that are capable of combusting more than or equal to 2.9 MW (10 MMBtu/h) heat input of fossil fuel but less than or equal to 29 MW (100 MMBtu/h) heat input of fossil fuel. If the heat recovery steam generator, fuel heater, or other affected facility is subject to this subpart, only emissions resulting from combustion of fuels in the steam generating unit are subject to this subpart. (The stationary combustion turbine emissions are subject to subpart GG or KKKK, as applicable, of this part.)

(f) Any affected facility that meets the applicability requirements of and is subject to subpart AAAA or subpart CCCC of this part is not subject to this subpart.

(g) Any facility that meets the applicability requirements and is subject to an EPA approved State or Federal section 111(d)/129 plan implementing subpart BBBB of this part is not subject to this subpart.

(h) Affected facilities that also meet the applicability requirements under subpart J or subpart Ja of this part are subject to the PM and NO_X standards under this subpart and the SO_2 standards under subpart J or subpart Ja of this part, as applicable.

(i) Temporary boilers are not subject to this subpart.

■ 31. Section 60.41c is amended as follows:

■ a. By removing the definition of "Cogeneration."
■ b. By revising the definition of "Distillate oil."
■ c. By adding a definition of "Temporary boiler" in alphabetical order.

§ 60.41c Definitions.

* * * * *

Distillate oil means fuel oil that complies with the specifications for fuel oil numbers 1 or 2, as defined by the American Society for Testing and Materials in ASTM D396 (incorporated by reference, see § 60.17), diesel fuel oil numbers 1 or 2, as defined by the American Society for Testing and Materials in ASTM D975 (incorporated by reference, see § 60.17), kerosine, as defined by the American Society of Testing and Materials in ASTM D3699 (incorporated by reference, see § 60.17), biodiesel as defined by the American Society of Testing and Materials in ASTM D6751 (incorporated by reference, see § 60.17), or biodiesel blends as defined by the American Society of Testing and Materials in ASTM D7467 (incorporated by reference, see § 60.17).

* * * * *

Temporary boiler means a steam generating unit that combusts natural gas or distillate oil with a potential SO_2 emissions rate no greater than 26 ng/J (0.060 lb/MMBtu), and the unit is designed to, and is capable of, being carried or moved from one location to another by means of, for example, wheels, skids, carrying handles, dollies, trailers, or platforms. A steam generating unit is not a temporary boiler if any one of the following conditions exists:

(1) The equipment is attached to a foundation.

(2) The steam generating unit or a replacement remains at a location for more than 180 consecutive days. Any temporary boiler that replaces a temporary boiler at a location and performs the same or similar function will be included in calculating the consecutive time period.

(3) The equipment is located at a seasonal facility and operates during the full annual operating period of the seasonal facility, remains at the facility for at least 2 years, and operates at that facility for at least 3 months each year.

(4) The equipment is moved from one location to another in an attempt to circumvent the residence time requirements of this definition.

* * * * *

■ 32. Section 60.42c is amended as follows:

■ a. By revising paragraph (c)(1) and (3).

■ b. By revising paragraph (d).

■ c. By revising paragraph (e)(1)(ii).

■ d. By revising paragraph (h) introductory text.

■ e. By revising paragraph (h)(3).

■ f. By adding paragraph (h)(4).

§ 60.42c Standard for sulfur dioxide (SO_2).

* * * * *

(c) * * *

(1) Affected facilities that have a heat input capacity of 22 MW (75 MMBtu/h) or less;

* * * * *

(3) Affected facilities located in a noncontinental area; or

* * * * *

(d) On and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that combusts oil shall cause to be discharged into the atmosphere from that affected facility any gases that contain SO_2 in excess of 215 ng/J (0.50 lb/MMBtu) heat input from oil; or, as an alternative, no owner or operator of an affected facility that combusts oil shall combust oil in the affected facility that contains greater than 0.5 weight percent sulfur. The percent reduction requirements are not applicable to affected facilities under this paragraph.

(e) * * *

(1) * * *

(ii) Has a heat input capacity greater than 22 MW (75 MMBtu/h); and

* * * * *

(h) For affected facilities listed under paragraphs (h)(1), (2), (3), or (4) of this section, compliance with the emission limits or fuel oil sulfur limits under this section may be determined based on a certification from the fuel supplier, as described under § 60.48c(f), as applicable.

* * * * *

(3) Coal-fired affected facilities with heat input capacities between 2.9 and 8.7 MW (10 and 30 MMBtu/h).

(4) Other fuels-fired affected facilities with heat input capacities between 2.9 and 8.7 MW (10 and 30 MMBtu/h).

* * * * *

■ 33. Section 60.43c is amended as follows:

■ a. By revising paragraph (a) introductory text.

■ b. By revising paragraph (b) introductory text.

■ c. By revising paragraph (c).

■ d. By revising paragraphs (e)(1), (3), and (4).

§ 60.43c Standard for particulate matter (PM).

(a) On and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005, that combusts coal or combusts mixtures of coal with other fuels and has a heat input capacity of 8.7 MW (30 MMBtu/h) or greater, shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of the following emission limits:

* * * * *

(b) On and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005, that combusts wood or combusts mixtures of wood with other fuels (except coal) and has a heat input capacity of 8.7 MW (30 MMBtu/h) or greater, shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of the following emissions limits:

* * * * *

(c) On and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that combusts coal, wood, or oil and has a heat input capacity of 8.7 MW (30 MMBtu/h) or greater shall cause to be discharged into the atmosphere from that affected facility any gases that exhibit greater than 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity. Owners and operators of an affected facility that elect to install, calibrate, maintain, and operate a continuous emissions monitoring system (CEMS) for measuring PM emissions according to the requirements of this subpart and are subject to a federally enforceable PM limit of 0.030 lb/MMBtu or less are exempt from the opacity standard specified in this paragraph (c).

* * * * *

(e)(1) On and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that commences construction, reconstruction, or modification after February 28, 2005, and that combusts coal, oil, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels and has a heat input capacity of 8.7 MW (30 MMBtu/h) or greater shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of 13 ng/J (0.030 lb/MMBtu) heat input, except as provided in paragraphs (e)(2), (e)(3), and (e)(4) of this section.

* * * * *

(3) On and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that commences modification after February 28, 2005, and that combusts over 30 percent wood (by heat input) on an annual basis and has a heat input capacity of 8.7 MW (30 MMBtu/h) or greater shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of 43 ng/J (0.10 lb/MMBtu) heat input.

(4) An owner or operator of an affected facility that commences construction, reconstruction, or modification after February 28, 2005, and that combusts only oil that contains no more than 0.50 weight percent sulfur

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or a mixture of 0.50 weight percent sulfur oil with other fuels not subject to a PM standard under § 60.43c and not using a post-combustion technology (except a wet scrubber) to reduce PM or SO_2 emissions is not subject to the PM limit in this section.

■ 34. Section 60.45c is amended as follows:

■ a. By revising paragraph (c)(14).

■ b. By revising paragraph (d).

§ 60.45c Compliance and performance test methods and procedures for particulate matter.

* * * * *

(c) * * *

(14) As of January 1, 2012, and within 90 days after the date of completing each performance test, as defined in § 60.8, conducted to demonstrate compliance with this subpart, you must submit relative accuracy test audit (*i.e.*, reference method) data and performance test (*i.e.*, compliance test) data, except opacity data, electronically to EPA's Central Data Exchange (CDX) by using the Electronic Reporting Tool (ERT) (see *http://www.epa.gov/ttn/chief/ert/ert tool.html/*) or other compatible electronic spreadsheet. Only data collected using test methods compatible with ERT are subject to this requirement to be submitted electronically into EPA's WebFIRE database.

(d) The owner or operator of an affected facility seeking to demonstrate compliance under § 60.43c(e)(4) shall follow the applicable procedures under § 60.48c(f). For residual oil-fired affected facilities, fuel supplier certifications are only allowed for facilities with heat input capacities between 2.9 and 8.7 MW (10 to 30 MMBtu/h).

■ 35. Section 60.47c is amended as follows:

■ a. By revising paragraph (a) introductory text.

■ b. By revising paragraphs (a)(1)(i) through (iii).

■ c. By revising paragraph (a)(2)(ii).

■ d. By revising paragraph (f).

■ e. By removing paragraph (g).

§ 60.47c Emission monitoring for particulate matter.

(a) Except as provided in paragraphs (c), (d), (e), and (f) of this section, the owner or operator of an affected facility combusting coal, oil, or wood that is subject to the opacity standards under § 60.43c shall install, calibrate, maintain, and operate a continuous opacity monitoring system (COMS) for measuring the opacity of the emissions discharged to the atmosphere and record the output of the system. The owner or operator of an affected facility subject to an opacity standard in § 60.43c(c) that is not required to use a COMS due to paragraphs (c), (d), (e), or (f) of this section that elects not to use a COMS shall conduct a performance test using Method 9 of appendix A–4 of this part and the procedures in § 60.11 to demonstrate compliance with the applicable limit in § 60.43c by April 29, 2011, within 45 days of stopping use of an existing COMS, or within 180 days after initial startup of the facility, whichever is later, and shall comply with either paragraphs (a)(1), (a)(2), or (a)(3) of this section. The observation period for Method 9 of appendix A–4 of this part performance tests may be reduced from 3 hours to 60 minutes if all 6-minute averages are less than 10 percent and all individual 15-second observations are less than or equal to 20 percent during the initial 60 minutes of observation.

(1) * * *

(i) If no visible emissions are observed, a subsequent Method 9 of appendix A–4 of this part performance test must be completed within 12 calendar months from the date that the most recent performance test was conducted or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later;

(ii) If visible emissions are observed but the maximum 6-minute average opacity is less than or equal to 5 percent, a subsequent Method 9 of appendix A–4 of this part performance test must be completed within 6 calendar months from the date that the most recent performance test was conducted or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later;

(iii) If the maximum 6-minute average opacity is greater than 5 percent but less than or equal to 10 percent, a subsequent Method 9 of appendix A–4 of this part performance test must be completed within 3 calendar months from the date that the most recent performance test was conducted or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later; or

* * * * *

(2) * * *

(ii) If no visible emissions are observed for 10 operating days during which an opacity standard is applicable, observations can be reduced to once every 7 operating days during which an opacity standard is applicable. If any visible emissions are observed, daily observations shall be resumed.

* * * * *

(f) An owner or operator of an affected facility that is subject to an opacity standard in § 60.43c(c) is not required to operate a COMS provided that the affected facility meets the conditions in either paragraphs (f)(1), (2), or (3) of this section.

(1) The affected facility uses a fabric filter (baghouse) as the primary PM control device and, the owner or operator operates a bag leak detection system to monitor the performance of the fabric filter according to the requirements in section § 60.48Da of this part.

(2) The affected facility uses an ESP as the primary PM control device, and the owner or operator uses an ESP predictive model to monitor the performance of the ESP developed in accordance and operated according to the requirements in section § 60.48Da of this part.

(3) The affected facility burns only gaseous fuels and/or fuel oils that contain no greater than 0.5 weight percent sulfur, and the owner or operator operates the unit according to a written site-specific monitoring plan approved by the permitting authority. This monitoring plan must include procedures and criteria for establishing and monitoring specific parameters for the affected facility indicative of compliance with the opacity standard. For testing performed as part of this site-specific monitoring plan, the permitting authority may require as an alternative to the notification and reporting requirements specified in §§ 60.8 and 60.11 that the owner or operator submit any deviations with the excess emissions report required under § 60.48c(c).

Subpart HHHH—[Removed and Reserved]

■ 36. Subpart HHHH is removed and reserved.

PART 63—[AMENDED]

■ 37. The authority citation for 40 CFR Part 63 continues to read as follows:

Authority: 42 U.S.C. 7401, *et seq.*

Subpart A—[Amended]

■ 38. Section 63.14 is amended as follows:

■ a. By adding paragraphs (b)(19) and (20).

■ b. By adding paragraphs (b)(22) and (23).

■ c. By adding paragraphs (b)(69) through (72).

■ d. By revising paragraph (i)(1).

§ 63.14 Incorporation by reference.

* * * * *

(b) * * *

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(19) ASTM D95–05 (Reapproved 2010), Standard Test Method for Water in Petroleum Products and Bituminous Materials by Distillation, approved May 1, 2010, IBR approved for § 63.10005(i)(4)(i).

(20) ASTM Method D388–05, Standard Classification of Coals by Rank, approved September 15, 2005, IBR approved for § 63.10042.

* * * * *

(22) ASTM Method D396–10, Standard Specification for Fuel Oils, including Appendix X1, approved October 1, 2010, IBR approved for § 63.10042.

(23) ASTM D4006–11, Standard Test Method for Water in Crude Oil by Distillation, including Annex A1 and Appendix X1, approved June 1, 2011, IBR approved for § 63.10005(i)(4)(ii).

* * * * *

(69) ASTM D4057–06 (Reapproved 2011), Standard Practice for Manual Sampling of Petroleum and Petroleum Products, including Annex A1, approved June 1, 2011, IBR approved for § 63.10005(i)(4)(iv).

(70) ASTM D4177–95 (Reapproved 2010), Standard Practice for Automatic Sampling of Petroleum and Petroleum Products, including Annexes A1 through A6 and Appendices X1 and X2, approved May 1, 2010, IBR approved for § 63.10005(i)(4)(iii).

(71) ASTM D6348–03 (Reapproved 2010), Standard Test Method for Determination of Gaseous Compounds by Extractive Direct Interface Fourier Transform Infrared (FTIR) Spectroscopy, including Annexes A1 through A8, approved October 1, 2010, IBR approved for table 1 to subpart UUUUU of this part, table 2 to subpart UUUUU of this part, table 5 to subpart UUUUU of this part, and appendix B to subpart UUUUU of this part.

(72) ASTM D6784–02 (Reapproved 2008), Standard Test Method for Elemental, Oxidized, Particle-Bound and Total Mercury in Flue Gas Generated from Coal-Fired Stationary Sources (Ontario Hydro Method), approved April 1, 2008, IBR approved for table 5 to subpart UUUUU of this part, and appendix A to subpart UUUUU of this part.

* * * * *

(i) * * *

(1) ANSI/ASME PTC 19.10–1981, "Flue and Exhaust Gas Analyses [part 10, Instruments and Apparatus]," IBR approved for §§ 63.309(k)(1)(iii), 63.865(b), 63.3166(a)(3), 63.3360(e)(1)(iii), 63.3545(a)(3), 63.3555(a)(3), 63.4166(a)(3), 63.4362(a)(3), 63.4766(a)(3), 63.4965(a)(3), 63.5160(d)(1)(iii), 63.9307(c)(2), 63.9323(a)(3), 63.11148(e)(3)(iii), 63.11155(e)(3), 63.11162(f)(3)(iii) and (f)(4), 63.11163(g)(1)(iii) and (g)(2), 63.11410(j)(1)(iii), 63.11551(a)(2)(i)(C), table 5 to subpart DDDDD of this part, table 1 to subpart ZZZZZ of this part, table 4 to subpart JJJJJJ of this part, and table 5 to subpart UUUUU of this part.

* * * * *

■ 39. Part 63 is amended by adding subpart UUUUU to read as follows:

Subpart UUUUU—National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units

Sec.

What This Subpart Covers

63.9980 What is the purpose of this subpart?
63.9981 Am I subject to this subpart?
63.9982 What is the affected source of this subpart?
63.9983 Are any EGUs not subject to this subpart?
63.9984 When do I have to comply with this subpart?
63.9985 What is a new EGU?

Emission Limitations and Work Practice Standards

63.9990 What are the subcategories of EGUs?
63.9991 What emission limitations, work practice standards, and operating limits must I meet?

General Compliance Requirements

63.10000 What are my general requirements for complying with this subpart?
63.10001 Affirmative defense for exceedence of emission limit during malfunction.

Testing and Initial Compliance Requirements

63.10005 What are my initial compliance requirements and by what date must I conduct them?
63.10006 When must I conduct subsequent performance tests or tune-ups?
63.10007 What methods and other procedures must I use for the performance tests?
63.10008 [Reserved]
63.10009 May I use emissions averaging to comply with this subpart?
63.10010 What are my monitoring, installation, operation, and maintenance requirements?
63.10011 How do I demonstrate initial compliance with the emission limitations and work practice standards?

Continuous Compliance Requirements

63.10020 How do I monitor and collect data to demonstrate continuous compliance?
63.10021 How do I demonstrate continuous compliance with the emission limitations, operating limits, and work practice standards?
63.10022 How do I demonstrate continuous compliance under the emissions averaging provision?
63.10023 How do I establish my PM CPMS operating limit and determine compliance with it?

Notifications, Reports, and Records

63.10030 What notifications must I submit and when?
63.10031 What reports must I submit and when?
63.10032 What records must I keep?
63.10033 In what form and how long must I keep my records?

Other Requirements and Information

63.10040 What parts of the General Provisions apply to me?
63.10041 Who implements and enforces this subpart?
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Tables to Subpart UUUUU of Part 63

Table 1 to Subpart UUUUU of Part 63—Emission Limits for New or Reconstructed EGUs
Table 2 to Subpart UUUUU of Part 63—Emission Limits for Existing EGUs
Table 3 to Subpart UUUUU of Part 63—Work Practice Standards
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Table 6 to Subpart UUUUU of Part 63—Establishing PM CPMS Operating Limits
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Table 8 to Subpart UUUUU of Part 63—Reporting Requirements
Table 9 to Subpart UUUUU of Part 63—Applicability of General Provisions to Subpart UUUUU
Appendix A to Subpart UUUUU—Hg Monitoring Provisions
Appendix B to Subpart UUUUU—HCl and HF Monitoring Provisions

Subpart UUUUU—National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units

What This Subpart Covers

§ 63.9980 What is the purpose of this subpart?

This subpart establishes national emission limitations and work practice standards for hazardous air pollutants (HAP) emitted from coal- and oil-fired electric utility steam generating units (EGUs) as defined in § 63.10042 of this subpart. This subpart also establishes requirements to demonstrate initial and continuous compliance with the emission limitations.

§ 63.9981 Am I subject to this subpart?

You are subject to this subpart if you own or operate a coal-fired EGU or an oil-fired EGU as defined in § 63.10042 of this subpart.

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§ 63.9982 What is the affected source of this subpart?

(a) This subpart applies to each individual or group of two or more new, reconstructed, and existing affected source(s) as described in paragraphs (a)(1) and (2) of this section within a contiguous area and under common control.

(1) The affected source of this subpart is the collection of all existing coal- or oil-fired EGUs, as defined in 63.10042, within a subcategory.

(2) The affected source of this subpart is each new or reconstructed coal- or oil-fired EGU as defined in 63.10042.

(b) An EGU is new if you commence construction of the coal- or oil-fired EGU after May 3, 2011, and you meet the applicability criteria at the time you commence construction.

(c) An EGU is reconstructed if you meet the reconstruction criteria as defined in § 63.2, you commence reconstruction after May 3, 2011, and you meet the applicability criteria at the time you commence reconstruction.

(d) An EGU is existing if it is not new or reconstructed. An existing electric steam generating unit that meets the applicability requirements after the effective date of this final rule due to a change process (*e.g.*, fuel or utilization) is considered to be an existing source under this subpart.

§ 63.9983 Are any EGUs not subject to this subpart?

The types of electric steam generating units listed in paragraphs (a) through (d) of this section are not subject to this subpart.

(a) Any unit designated as a stationary combustion turbine, other than an integrated gasification combined cycle (IGCC) unit, covered by 40 CFR part 63, subpart YYYY.

(b) Any electric utility steam generating unit that is not a coal- or oil-fired EGU and combusts natural gas for more than 10.0 percent of the average annual heat input during any 3 calendar years or for more than 15.0 percent of the annual heat input during any calendar year.

(c) Any electric utility steam generating unit that has the capability of combusting more than 25 MW of coal or oil but did not fire coal or oil for more than 10.0 percent of the average annual heat input during any 3 calendar years or for more than 15.0 percent of the annual heat input during any calendar year. Heat input means heat derived from combustion of fuel in an EGU and does not include the heat derived from preheated combustion air, recirculated flue gases or exhaust gases from other sources (such as stationary gas turbines, internal combustion engines, and industrial boilers).

(d) Any electric steam generating unit combusting solid waste is a solid waste incineration unit subject to standards established under sections 129 and 111 of the Clean Air Act.

§ 63.9984 When do I have to comply with this subpart?

(a) If you have a new or reconstructed EGU, you must comply with this subpart by April 16, 2012 or upon startup of your EGU, whichever is later, and as further provided for in § 63.10005(g).

(b) If you have an existing EGU, you must comply with this subpart no later than April 16, 2015.

(c) You must meet the notification requirements in § 63.10030 according to the schedule in § 63.10030 and in subpart A of this part. Some of the notifications must be submitted before you are required to comply with the emission limits and work practice standards in this subpart.

(d) An electric steam generating unit that does not meet the definition of an EGU subject to this subpart on April 16, 2012 for new sources or April 16, 2015 for existing sources must comply with the applicable existing source provisions of this subpart on the date such unit meets the definition of an EGU subject to this subpart.

(e) If you own or operate an electric steam generating unit that is exempted from this subpart under § 63.9983(d), if the manner of operating the unit changes such that the combustion of waste is discontinued and the unit becomes a coal-fired or oil-fired EGU (as defined in § 63.10042), you must be in compliance with this subpart on April 16, 2015 or on the effective date of the switch from waste combustion to coal or oil combustion, whichever is later.

(f) You must demonstrate that compliance has been achieved, by conducting the required performance tests and other activities, no later than 180 days after the applicable date in paragraph (a), (b), (c), (d), or (e) of this section.

§ 63.9985 What is a new EGU?

(a) A new EGU is an EGU that meets any of the criteria specified in paragraph (a)(1) through (a)(2) of this section.

(1) An EGU that commenced construction after May 3, 2011.

(2) An EGU that commenced reconstruction or modification after May 3, 2011.

(b) [Reserved]

Emission Limitations and Work Practice Standards

§ 63.9990 What are the subcategories of EGUs?

(a) Coal-fired EGUs are subcategorized as defined in paragraphs (a)(1) through (a)(2) of this section and as defined in § 63.10042.

(1) EGUs designed for coal with a heating value greater than or equal to 8,300 Btu/lb, and

(2) EGUs designed for low rank virgin coal.

(b) Oil-fired EGUs are subcategorized as noted in paragraphs (b)(1) through (b)(4) of this section and as defined in § 63.10042.

(1) Continental liquid oil-fired EGUs

(2) Non-continental liquid oil-fired EGUs,

(3) Limited-use liquid oil-fired EGUs, and

(4) EGUs designed to burn solid oil-derived fuel.

(c) IGCC units combusting either gasified coal or gasified solid oil-derived fuel. For purposes of compliance, monitoring, recordkeeping, and reporting requirements in this subpart, IGCC units are subject in the same manner as coal-fired units and solid oil-derived fuel-fired units, unless otherwise indicated.

§ 63.9991 What emission limitations, work practice standards, and operating limits must I meet?

(a) You must meet the requirements in paragraphs (a)(1) and (2) of this section. You must meet these requirements at all times.

(1) You must meet each emission limit and work practice standard in Table 1 through 3 to this subpart that applies to your EGU, for each EGU at your source, except as provided under § 63.10009.

(2) You must meet each operating limit in Table 4 to this subpart that applies to your EGU.

(b) As provided in § 63.6(g), the Administrator may approve use of an alternative to the work practice standards in this section.

(c) You may use the alternate SO_2 limit in Tables 1 and 2 to this subpart only if your coal-fired EGU:

(1) Has a system using wet or dry flue gas desulfurization technology and SO_2 continuous emissions monitoring system (CEMS) installed on the unit; and

(2) At all times, you operate the wet or dry flue gas desulfurization technology installed on the unit consistent with § 63.10000(b).

General Compliance Requirements

§ 63.10000 What are my general requirements for complying with this subpart?

(a) You must be in compliance with the emission limits and operating limits in this subpart. These limits apply to you at all times except during periods of startup and shutdown; however, for coal-fired, liquid oil-fired, or solid oil-derived fuel-fired EGUs, you are required to meet the work practice requirements in Table 3 to this subpart during periods of startup or shutdown.

(b) At all times you must operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. Determination of whether such operation and maintenance procedures are being used will be based on information available to the EPA Administrator which may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source.

(c)(1) For coal-fired units and solid oil-derived fuel-fired units, initial performance testing is required for all pollutants, to demonstrate compliance with the applicable emission limits.

(i) For a coal-fired or solid oil-derived fuel-fired EGU or IGCC EGU, you may conduct the initial performance testing in accordance with § 63.10005(h), to determine whether the unit qualifies as a low emitting EGU (LEE) for one or more applicable emissions limits, with two exceptions:

(A) You may not pursue the LEE option if your coal-fired, IGCC, or solid oil-derived fuel-fired EGU is equipped with an acid gas scrubber and has a main stack and bypass stack exhaust configuration, and

(B) You may not pursue the LEE option for Hg if your coal-fired, solid oil-fired fuel fired EGU or IGCC EGU is new.

(ii) For a qualifying LEE for Hg emissions limits, you must conduct a 30-day performance test using Method 30B at least once every 12 calendar months to demonstrate continued LEE status.

(iii) For a qualifying LEE of any other applicable emissions limits, you must conduct a performance test at least once every 36 calendar months to demonstrate continued LEE status.

(iv) If your coal-fired or solid oil-derived fuel-fired EGU or IGCC EGU does not qualify as a LEE for total non-mercury HAP metals, individual non-mercury HAP metals, or filterable particulate matter (PM), you must demonstrate compliance through an initial performance test and you must monitor continuous performance through either use of a particulate matter continuous parametric monitoring system (PM CPMS), a PM CEMS, or compliance performance testing repeated quarterly.

(A) If you elect to use PM CPMS, you will establish a site-specific operating limit corresponding to the results of the performance test demonstrating compliance with the pollutant with which you choose to comply: total non-mercury HAP metals, individual non-mercury HAP metals or filterable PM. You will use the PM CPMS to demonstrate continuous compliance with this operating limit. If you elect to use a PM CPMS, you must repeat the performance test annually for the selected pollutant limit and reassess and adjust the site-specific operating limit in accordance with the results of the performance test.

(B) You may also opt to install and operate a particulate matter CEMS certified in accordance with Performance Specification 11 and Procedure 2 of 40 CFR part 60, Appendices B and F, respectively, in accordance with § 63.10010(i).

(v) If your coal-fired or solid oil-derived fuel-fired EGU does not qualify as a LEE for hydrogen chloride (HCl), you may demonstrate initial and continuous compliance through use of an HCl CEMS, installed and operated in accordance with Appendix B to this subpart. As an alternative to HCl CEMS, you may demonstrate initial and continuous compliance by conducting an initial and periodic quarterly performance stack test for HCl. If your EGU uses wet or dry flue gas desulfurization technology (this includes limestone injection into a fluidized bed combustion unit), you may apply a second alternative to HCl CEMS by installing and operating a sulfur dioxide (SO_2) CEMS installed and operated in accordance with part 75 of this chapter to demonstrate compliance with the applicable SO_2 emissions limit.

(vi) If your coal-fired or solid oil-derived fuel-fired EGU does not qualify as a LEE for Hg, you must demonstrate initial and continuous compliance through use of a Hg CEMS or a sorbent trap monitoring system, in accordance with appendix A to this subpart.

(2) For liquid oil-fired EGUs, except limited use liquid oil-fired EGUs, initial performance testing is required for all pollutants, to demonstrate compliance with the applicable emission limits.

(i) For an existing liquid oil-fired unit, you may conduct the performance testing in accordance with § 63.10005(h), to determine whether the unit qualifies as a LEE for one or more pollutants. For a qualifying LEE for Hg emissions limits, you must conduct a 30-day performance test using Method 30B at least once every 12 calendar months to demonstrate continued LEE status. For a qualifying LEE of any other applicable emissions limits, you must conduct a performance test at least once every 36 calendar months to demonstrate continued LEE status.

(ii) If your existing liquid oil-fired unit does not qualify as a LEE for total HAP metals (including mercury), individual metals (including mercury), or filterable PM you must demonstrate compliance through an initial performance test and you must monitor continuous performance through either use of a PM CPMS, a PM CEMS, or performance testing conducted quarterly.

(A) If you elect to use PM CPMS, you will establish a site-specific operating limit corresponding to the results of the performance test demonstrating compliance with the pollutant with which you choose to comply: total HAP metals, individual HAP metals, or filterable PM. You will use the PM CPMS to demonstrate continuous compliance with this operating limit. If you elect to use a PM CPMS, you must repeat the performance test at least annually for the selected pollutant limit and reassess and adjust the site-specific operating limit in accordance with the results of the performance test.

(B) If you elect to use a PM CEMS, you will use the CEMS in accordance with § 63.10010(i) to demonstrate initial and continuous compliance with the filterable PM emission limit.

(iii) If your existing liquid oil-fired unit does not qualify as a LEE for hydrogen chloride (HCl) or for hydrogen fluoride (HF), you may demonstrate initial and continuous compliance through use of an HCl CEMS, an HF CEMS, or an HCl and HF CEMS, installed and operated in accordance with Appendix B to this rule. As an alternative to HCl CEMS, HF CEMS, or HCl and HF CEMS, you may demonstrate initial and continuous compliance by conducting periodic quarterly performance stack tests for HCl and HF. If you elect to demonstrate compliance through quarterly performance testing, then you must also develop a site-specific monitoring plan to ensure that the operations of the unit remain consistent with those during the performance test. As another alternative, you may measure or obtain, and keep

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records of, fuel moisture content; as long as fuel moisture does not exceed 1.0 percent by weight, you need not conduct other HCl or HF monitoring or testing.

(iv) If your unit qualifies as a limited-use liquid oil-fired as defined in § 63.10042, then you are not subject to the emission limits in Tables 1 and 2, but must comply with the performance tune-up work practice requirements in Table 3.

(d)(1) If you demonstrate compliance with any applicable emissions limit through use of a continuous monitoring system (CMS), where a CMS includes a continuous parameter monitoring system (CPMS) as well as a continuous emissions monitoring system (CEMS), you must develop a site-specific monitoring plan and submit this site-specific monitoring plan, if requested, at least 60 days before your initial performance evaluation (where applicable) of your CMS. This requirement also applies to you if you petition the Administrator for alternative monitoring parameters under § 63.8(f). This requirement to develop and submit a site-specific monitoring plan does not apply to affected sources with existing monitoring plans that apply to CEMS and CPMS prepared under Appendix B to part 60 or part 75 of this chapter, and that meet the requirements of § 63.10010. Using the process described in § 63.8(f)(4), you may request approval of monitoring system quality assurance and quality control procedures alternative to those specified in this paragraph of this section and, if approved, include those in your site-specific monitoring plan. The monitoring plan must address the provisions in paragraphs (d)(2) through (5) of this section.

(2) The site-specific monitoring plan shall include the information specified in paragraphs (d)(5)(i) through (d)(5)(vii) of this section. Alternatively, the requirements of paragraphs (d)(5)(i) through (d)(5)(vii) are considered to be met for a particular CMS or sorbent trap monitoring system if:

(i) The CMS or sorbent trap monitoring system is installed, certified, maintained, operated, and quality-assured either according to part 75 of this chapter, or appendix A or B to this subpart; and

(ii) The recordkeeping and reporting requirements of part 75 of this chapter, or appendix A or B to this subpart, that pertain to the CMS are met.

(3) If requested by the Administrator, you must submit the monitoring plan (or relevant portion of the plan) at least 60 days before the initial performance evaluation of a particular CMS, except where the CMS has already undergone a performance evaluation that meets the requirements of § 63.10010 (*e.g.*, if the CMS was previously certified under another program).

(4) You must operate and maintain the CMS according to the site-specific monitoring plan.

(5) The provisions of the site-specific monitoring plan must address the following items:

(i) Installation of the CEMS or sorbent trap monitoring system sampling probe or other interface at a measurement location relative to each affected process unit such that the measurement is representative of control of the exhaust emissions (*e.g.*, on or downstream of the last control device). See § 63.10010(a) for further details. For CPMS installations, follow the procedures in § 63.10010(h).

(ii) Performance and equipment specifications for the sample interface, the pollutant concentration or parametric signal analyzer, and the data collection and reduction systems.

(iii) Schedule for conducting initial and periodic performance evaluations.

(iv) Performance evaluation procedures and acceptance criteria (*e.g.*, calibrations), including ongoing data quality assurance procedures in accordance with the general requirements of § 63.8(d).

(v) On-going operation and maintenance procedures, in accordance with the general requirements of §§ 63.8(c)(1)(ii), (c)(3), and (c)(4)(ii).

(vi) Conditions that define a CMS that is out of control consistent with § 63.8(c)(7)(i) and for responding to out of control periods consistent with §§ 63.8(c)(7)(ii) and (c)(8).

(vii) On-going recordkeeping and reporting procedures, in accordance with the general requirements of §§ 63.10(c), (e)(1), and (e)(2)(i), or as specifically required under this subpart.

(e) As part of your demonstration of continuous compliance, you must perform periodic tune-ups of your EGU(s), according to § 63.10021(e).

(f) You are subject to the requirements of this subpart for at least 6 months following the last date you met the definition of an EGU subject to this subpart (*e.g.*, 6 months after a cogeneration unit provided more than one third of its potential electrical output capacity and more than 25 megawatts electrical output to any power distributions system for sale). You may opt to remain subject to the provisions of this subpart beyond 6 months after the last date you met the definition of an EGU subject to this subpart, unless you are a solid waste incineration unit subject to standards under CAA section 129 (*e.g.*, 40 CFR part 60, subpart CCCC (New Source Performance Standards (NSPS) for Commercial and Industrial Solid Waste Incineration Units, or Subpart DDDD (Emissions Guidelines (EG) for Existing Commercial and Industrial Solid Waste Incineration Units). Notwithstanding the provisions of this subpart, an EGU that starts combusting solid waste is immediately subject to standards under CAA section 129 and the EGU remains subject to those standards until the EGU no longer meets the definition of a solid waste incineration unit consistent with the provisions of the applicable CAA section 129 standards.

(g) If you no longer meet the definition of an EGU subject to this subpart you must be in compliance with any newly applicable standards on the date you are no longer subject to this subpart. The date you are no longer subject to this subpart is a date selected by you, that must be at least 6 months from the date that you last met the definition of an EGU subject to this subpart or the date you begin combusting solid waste, consistent with § 63.9983(d). Your source must remain in compliance with this subpart until the date you select to cease complying with this subpart or the date you begin combusting solid waste, whichever is earlier.

(h)(1) If you own or operate an EGU that does not meet the definition of an EGU subject to this subpart on April 16, 2015, and you commence or recommence operations that cause you to meet the definition of an EGU subject to this subpart, you are subject to the provisions of this subpart, including, but not limited to, the emission limitations and the monitoring requirements, as of the first day you meet the definition of an EGU subject to this subpart. You must complete all initial compliance demonstrations for this subpart applicable to your EGU within 180 days after you commence or recommence operations that cause you to meet the definition of an EGU subject to this subpart.

(2) You must provide 30 days prior notice of the date you intend to commence or recommence operations that cause you to meet the definition of an EGU subject to this subpart. The notification must identify:

(i) The name of the owner or operator of the EGU, the location of the facility, the unit(s) that will commence or recommence operations that will cause the unit(s) to meet the definition of an EGU subject to this subpart, and the date of the notice;

(ii) The 40 CFR part 60, part 62, or part 63 subpart and subcategory

currently applicable to your unit(s), and the subcategory of this subpart that will be applicable after you commence or recommence operation that will cause the unit(s) to meet the definition of an EGU subject to this subpart;

(iii) The date on which you became subject to the currently applicable emission limits;

(iv) The date upon which you will commence or recommence operations that will cause your unit to meet the definition of an EGU subject to this subpart, consistent with paragraph (f) of this section.

(i)(1) If you own or operate an EGU subject to this subpart, and it has been at least 6 months since you operated in a manner that caused you to meet the definition of an EGU subject to this subpart, you may, consistent with paragraph (g) of this section, select the date on which your EGU will no longer be subject to this subpart. You must be in compliance with any newly applicable section 112 or 129 standards on the date you selected.

(2) You must provide 30 days prior notice of the date your EGU will cease complying with this subpart. The notification must identify:

(i) The name of the owner or operator of the EGU(s), the location of the facility, the EGU(s) that will cease complying with this subpart, and the date of the notice;

(ii) The currently applicable subcategory under this subpart, and any 40 CFR part 60, part 62, or part 63 subpart and subcategory that will be applicable after you cease complying with this subpart;

(iii) The date on which you became subject to this subpart;

(iv) The date upon which you will cease complying with this subpart, consistent with paragraph (g) of this section.

(j) All air pollution control equipment necessary for compliance with any newly applicable emissions limits which apply as a result of the cessation or commencement or recommencement of operations that cause your EGU to meet the definition of an EGU subject to this subpart must be installed and operational as of the date your source ceases to be or becomes subject to this subpart.

(k) All monitoring systems necessary for compliance with any newly applicable monitoring requirements which apply as a result of the cessation or commencement or recommencement of operations that cause your EGU to meet the definition of an EGU subject to this subpart must be installed and operational as of the date your source ceases to be or becomes subject to this subpart. All calibration and drift checks must be performed as of the date your source ceases to be or becomes subject to this subpart. You must also comply with provisions of §§ 63.10010, 63.10020, and 63.10021 of this subpart. Relative accuracy tests must be performed as of the performance test deadline for PM CEMS, if applicable. Relative accuracy testing for other CEMS need not be repeated if that testing was previously performed consistent with CAA section 112 monitoring requirements or monitoring requirements under this subpart.

§ 63.10001 Affirmative defense for exceedence of emission limit during malfunction.

In response to an action to enforce the standards set forth in § 63.9991 you may assert an affirmative defense to a claim for civil penalties for exceedances of such standards that are caused by malfunction, as defined at 40 CFR 63.2. Appropriate penalties may be assessed, however, if you fail to meet your burden of proving all of the requirements in the affirmative defense. The affirmative defense shall not be available for claims for injunctive relief.

(a) To establish the affirmative defense in any action to enforce such a limit, you must timely meet the notification requirements in paragraph (b) of this section, and must prove by a preponderance of evidence that:

(1) The excess emissions:

(i) Were caused by a sudden, infrequent, and unavoidable failure of air pollution control and monitoring equipment, process equipment, or a process to operate in a normal or usual manner, and

(ii) Could not have been prevented through careful planning, proper design or better operation and maintenance practices; and

(iii) Did not stem from any activity or event that could have been foreseen and avoided, or planned for; and

(iv) Were not part of a recurring pattern indicative of inadequate design, operation, or maintenance; and

(2) Repairs were made as expeditiously as possible when the applicable emission limitations were being exceeded. Off-shift and overtime labor were used, to the extent practicable to make these repairs; and

(3) The frequency, amount and duration of the excess emissions (including any bypass) were minimized to the maximum extent practicable during periods of such emissions; and

(4) If the excess emissions resulted from a bypass of control equipment or a process, then the bypass was unavoidable to prevent loss of life, personal injury, or severe property damage; and

(5) All possible steps were taken to minimize the impact of the excess emissions on ambient air quality, the environment and human health; and

(6) All emissions monitoring and control systems were kept in operation if at all possible, consistent with safety and good air pollution control practices; and

(7) All of the actions in response to the excess emissions were documented by properly signed, contemporaneous operating logs; and

(8) At all times, the affected source was operated in a manner consistent with good practices for minimizing emissions; and

(9) A written root cause analysis has been prepared, the purpose of which is to determine, correct, and eliminate the primary causes of the malfunction and the excess emissions resulting from the malfunction event at issue. The analysis shall also specify, using best monitoring methods and engineering judgment, the amount of excess emissions that were the result of the malfunction.

(b) *Notification.* The owner or operator of the affected source experiencing an exceedance of its emission limit(s) during a malfunction shall notify the Administrator by telephone or facsimile (FAX) transmission as soon as possible, but no later than two business days after the initial occurrence of the malfunction or, if it is not possible to determine within two business days whether the malfunction caused or contributed to an exceedance, no later than two business days after the owner or operator knew or should have known that the malfunction caused or contributed to an exceedance, but, in no event later than two business days after the end of the averaging period, if it wishes to avail itself of an affirmative defense to civil penalties for that malfunction. The owner or operator seeking to assert an affirmative defense shall also submit a written report to the Administrator within 45 days of the initial occurrence of the exceedance of the standard in § 63.9991 to demonstrate, with all necessary supporting documentation, that it has met the requirements set forth in paragraph (a) of this section. The owner or operator may seek an extension of this deadline for up to 30 additional days by submitting a written request to the Administrator before the expiration of the 45 day period. Until a request for an extension has been approved by the Administrator, the owner or operator is subject to the requirement to submit such report

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within 45 days of the initial occurrence of the exceedance.

Testing and Initial Compliance Requirements

§ 63.10005 What are my initial compliance requirements and by what date must I conduct them?

(a) *General requirements.* For each of your affected EGUs, you must demonstrate initial compliance with each applicable emissions limit in Table 1 or 2 of this subpart through performance testing. Where two emissions limits are specified for a particular pollutant (e.g., a heat input-based limit in lb/MMBtu and an electrical output-based limit in lb/MWh), you may demonstrate compliance with either emission limit. For a particular compliance demonstration, you may be required to conduct one or more of the following activities in conjunction with performance testing: collection of hourly electrical load data (megawatts); establishment of operating limits according to § 63.10011 and Tables 4 and 7 to this subpart; and CMS performance evaluations. In all cases, you must demonstrate initial compliance no later than the applicable date in paragraph (f) of this section for tune-up work practices for existing EGUs, in § 63.9984 for other requirements for existing EGUs, and in paragraph (g) of this section for all requirements for new EGUs.

(1) To demonstrate initial compliance with an applicable emissions limit in Table 1 or 2 to this subpart using stack testing, the initial performance test generally consists of three runs at specified process operating conditions using approved methods. If you are required to establish operating limits (see paragraph (d) of this section and Table 4 to this subpart), you must collect all applicable parametric data during the performance test period. Also, if you choose to comply with an electrical output-based emission limit, you must collect hourly electrical load data during the test period.

(2) To demonstrate initial compliance using either a CMS that measures HAP concentrations directly (*i.e.*, an Hg, HCl, or HF CEMS, or a sorbent trap monitoring system) or an SO_2 or PM CEMS, the initial performance test consists of 30 boiler operating days of data collected by the initial compliance demonstration date specified in § 63.10005 with the certified monitoring system.

(i) The 30-boiler operating day CMS performance test must demonstrate compliance with the applicable Hg, HCl, HF, PM, or SO_2 emissions limit in Table 1 or 2 to this subpart.

(ii) If you choose to comply with an electrical output-based emission limit, you must collect hourly electrical load data during the performance test period.

(b) *Performance testing requirements.* If you choose to use performance testing to demonstrate initial compliance with the applicable emissions limits in Tables 1 and 2 to this subpart for your EGUs, you must conduct the tests according to § 63.10007 and Table 5 to this subpart. For the purposes of the initial compliance demonstration, you may use test data and results from a performance test conducted prior to the date on which compliance is required as specified in § 63.9984, provided that the following conditions are fully met:

(1) For a performance test based on stack test data, the test was conducted no more than 12 calendar months prior to the date on which compliance is required as specified in § 63.9984;

(2) For a performance test based on data from a certified CEMS or sorbent trap monitoring system, the test consists of all valid data CMS data recorded in the 30 boiler operating days immediately preceding that date;

(3) The performance test was conducted in accordance with all applicable requirements in § 63.10007 and Table 5 to this subpart;

(4) A record of all parameters needed to convert pollutant concentrations to units of the emission standard (e.g., stack flow rate, diluent gas concentrations, hourly electrical loads) is available for the entire performance test period; and

(5) For each performance test based on stack test data, you certify, and keep documentation demonstrating, that the EGU configuration, control devices, and fuel(s) have remained consistent with conditions since the prior performance test was conducted.

(c) *Operating limits.* In accordance with § 63.10010 and Table 4 to this subpart, you may be required to establish operating limits using PM CPMS and using site-specific monitoring for certain liquid oil-fired units as part of your initial compliance demonstration.

(d) *CMS requirements.* If, for a particular emission or operating limit, you are required to (or elect to) demonstrate initial compliance using a continuous monitoring system, the CMS must pass a performance evaluation prior to the initial compliance demonstration. If a CMS has been previously certified under another state or federal program and is continuing to meet the on-going quality-assurance (QA) requirements of that program, then, provided that the certification and QA provisions of that program meet the applicable requirements of §§ 63.10010(b) through (h), an additional performance evaluation of the CMS is not required under this subpart.

(1) For an affected coal-fired, solid oil-derived fuel-fired, or liquid oil-fired EGU, you may demonstrate initial compliance with the applicable SO_2, HCl, or HF emissions limit in Table 1 or 2 of this subpart through use of an SO_2, HCl, or HF CEMS installed and operated in accordance with part 75 of this chapter or Appendix B to this subpart, as applicable. You may also demonstrate compliance with a filterable PM emission limit in Table 1 or 2 of this subpart through use of a PM CEMS installed, certified, and operated in accordance with § 63.10010(i). Initial compliance is achieved if the arithmetic average of 30-boiler operating days of quality-assured CEMS data, expressed in units of the standard (see § 63.10007(e)), meets the applicable SO_2, PM, HCl, or HF emissions limit in Table 1 or 2 to this subpart. Use Equation 19–19 of Method 19 in appendix A–7 to part 60 of this chapter to calculate the 30-boiler operating day average emissions rate. (Note: for this calculation, the term E_{hj} in Equation 19–19 must be in the same units of measure as the applicable HCl or HF emission limit in Table 1 or 2 to this subpart).

(2) For affected coal-fired or solid oil-derived fuel-fired EGUs that demonstrate compliance with the applicable emission limits for total non-mercury HAP metals, individual non-mercury HAP metals, total HAP metals, individual HAP metals, or filterable PM listed in Table 1 or 2 to this subpart using initial performance testing and continuous monitoring with PM CPMS:

(i) You must demonstrate initial compliance no later than the applicable date specified in § 63.9984(f) for existing EGUs and in paragraph (g) of this section for new EGUs.

(ii) You must demonstrate continuous compliance with the PM CPMS site-specific operating limit that corresponding to the results of the performance test demonstrating compliance with the pollutant with which you choose to comply.

(iii) You must repeat the performance test annually for the selected pollutant emissions limit and reassess and adjust the site-specific operating limit in accordance with the results of the performance test.

(3) For affected EGUs that are either required to or elect to demonstrate initial compliance with the applicable Hg emission limit in Table 1 or 2 of this

subpart using Hg CEMS or sorbent trap monitoring systems, initial compliance must be demonstrated no later than the applicable date specified in § 63.9984(f) for existing EGUs and in paragraph (g) of this section for new EGUs. Initial compliance is achieved if the arithmetic average of 30-boiler operating days of quality-assured CEMS (or sorbent trap monitoring system) data, expressed in units of the standard (see section 6.2 of appendix A to this subpart), meets the applicable Hg emission limit in Table 1 or 2 to this subpart.

(4) For affected liquid oil-fired EGUs that demonstrate compliance with the applicable emission limits for HCl or HF listed in Table 1 or 2 to this subpart using quarterly testing and continuous monitoring with a CMS:

(i) You must demonstrate initial compliance no later than the applicable date specified in § 63.9984 for existing EGUs and in paragraph (g) of this section for new EGUs.

(ii) You must demonstrate continuous compliance with the CMS site-specific operating limit that corresponding to the results of the performance test demonstrating compliance with the HCl or HF emissions limit.

(iii) You must repeat the performance test annually for the HCl or HF emissions limit and reassess and adjust the site-specific operating limit in accordance with the results of the performance test.

(e) *Tune-ups.* All affected EGUs are subject to the work practice standards in Table 3 of this subpart. As part of your initial compliance demonstration, you must conduct a performance tune-up of your EGU according to § 63.10021(e).

(f) For existing affected sources a tune-up may occur prior to April 16, 2012, so that existing sources without neural networks have up to 42 calendar months (3 years from promulgation plus 180 days) or, in the case of units employing neural network combustion controls, up to 54 calendar months (48 months from promulgation plus 180 days) after the date that is specified for your source in § 63.9984 and according to the applicable provisions in § 63.7(a)(2) as cited in Table 9 to this subpart to demonstrate compliance with this requirement. If a tune-up occurs prior to such date, the source must maintain adequate records to show that the tune-up met the requirements of this standard.

(g) If your new or reconstructed affected source commenced construction or reconstruction between May 3, 2011, and July 2, 2011, you must demonstrate initial compliance with either the proposed emission limits or the promulgated emission limits no later than 180 days after April 16, 2012 or within 180 days after startup of the source, whichever is later, according to § 63.7(a)(2)(ix).

(1) For the new or reconstructed affected source described in this paragraph (g), if you choose to comply with the proposed emission limits when demonstrating initial compliance, you must conduct a second compliance demonstration for the promulgated emission limits within 3 years after April 16, 2012 or within 3 years after startup of the affected source, whichever is later.

(2) If your new or reconstructed affected source commences construction or reconstruction after April 16, 2012, you must demonstrate initial compliance with the promulgated emission limits no later than 180 days after startup of the source.

(h) *Low emitting EGUs.* The provisions of this paragraph (h) apply to pollutants with emissions limits from new EGUs except Hg and to all pollutants with emissions limits from existing EGUs. You may not pursue this compliance option if your existing EGU is equipped with an acid gas scrubber and has a main stack and bypass stack exhaust configuration.

(1) An EGU may qualify for low emitting EGU (LEE) status for Hg, HCl, HF, filterable PM, total non-Hg HAP metals, or individual non-Hg HAP metals (or total HAP metals or individual HAP metals, for liquid oil-fired EGUs) if you collect performance test data that meet the requirements of this paragraph (h), and if those data demonstrate:

(i) For all pollutants except Hg, performance test emissions results less than 50 percent of the applicable emissions limits in Table 1 or 2 to this subpart for all required testing for 3 consecutive years; or

(ii) For Hg emissions from an existing EGU, either:

(A) Average emissions less than 10 percent of the applicable Hg emissions limit in Table 2 to this subpart (expressed either in units of lb/TBtu or lb/GWh); or

(B) Potential Hg mass emissions of 29.0 or fewer pounds per year and compliance with the applicable Hg emission limit in Table 2 to this subpart (expressed either in units of lb/TBtu or lb/GWh).

(2) For all pollutants except Hg, you must conduct all required performance tests described in § 63.10007 to demonstrate that a unit qualifies for LEE status.

(i) When conducting emissions testing to demonstrate LEE status, you must increase the minimum sample volume specified in Table 1 or 2 nominally by a factor of two.

(ii) Follow the instructions in § 63.10007(e) and Table 5 to this subpart to convert the test data to the units of the applicable standard.

(3) For Hg, you must conduct a 30-boiler operating day performance test using Method 30B in appendix A–8 to part 60 of this chapter to determine whether a unit qualifies for LEE status. Locate the Method 30B sampling probe tip at a point within the 10 percent centroidal area of the duct at a location that meets Method 1 in appendix A–1 to part 60 of this chapter and conduct at least three nominally equal length test runs over the 30-boiler operating day test period. Collect Hg emissions data continuously over the entire test period (except when changing sorbent traps or performing required reference method QA procedures), under all process operating conditions. You may use a pair of sorbent traps to sample the stack gas for no more than 10 days.

(i) Depending on whether you intend to assess LEE status for Hg in terms of the lb/TBtu or lb/GWh emission limit in Table 2 to this subpart or in terms of the annual Hg mass emissions limit of 29.0 lb/year, you will have to collect some or all of the following data during the 30-boiler operating day test period (see paragraph (h)(3)(iii) of this section):

(A) Diluent gas (CO_2 or O_2) data, using either Method 3A in appendix A–3 to part 60 of this chapter or a diluent gas monitor that has been certified according to part 75 of this chapter.

(B) Stack gas flow rate data, using either Method 2, 2F, or 2G in appendices A–1 and A–2 to part 60 of this chapter, or a flow rate monitor that has been certified according to part 75 of this chapter.

(C) Stack gas moisture content data, using either Method 4 in appendix A–1 to part 60 of this chapter, or a moisture monitoring system that has been certified according to part 75 of this chapter. Alternatively, an appropriate fuel-specific default moisture value from § 75.11(b) of this chapter may be used in the calculations or you may petition the Administrator under § 75.66 of this chapter for use of a default moisture value for non-coal-fired units.

(D) Hourly electrical load data (megawatts), from facility records.

(ii) If you use CEMS to measure CO_2 (or O_2) concentration, and/or flow rate, and/or moisture, record hourly average values of each parameter throughout the 30-boiler operating day test period. If you opt to use EPA reference methods rather than CEMS for any parameter, you must perform at least one

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representative test run on each operating day of the test period, using the applicable reference method.

(iii) Calculate the average Hg concentration, in $\mu g/m^3$ (dry basis), for the 30-boiler operating day performance test, as the arithmetic average of all Method 30B sorbent trap results. Also calculate, as applicable, the average values of CO_2 or O_2 concentration, stack gas flow rate, stack gas moisture content, and electrical load for the test period. Then:

(A) To express the test results in units of lb/TBtu, follow the procedures in § 63.10007(e). Use the average Hg concentration and diluent gas values in the calculations.

(B) To express the test results in units of lb/GWh, use Equations A–3 and A–4 in section 6.2.2 of appendix A to this subpart, replacing the hourly values "C_h", "Q_h", "B_{ws}" and "$(MW)_h$" with the average values of these parameters from the performance test.

(C) To calculate pounds of Hg per year, use one of the following methods:

(*1*) Multiply the average lb/TBtu Hg emission rate (determined according to paragraph (h)(3)(iii)(A) of this section) by the maximum potential annual heat input to the unit (TBtu), which is equal to the maximum rated unit heat input (TBtu/hr) times 8,760 hours. If the maximum rated heat input value is expressed in units of MMBtu/hr, multiply it by 10^6 to convert it to TBtu/hr; or

(*2*) Multiply the average lb/GWh Hg emission rate (determined according to paragraph (h)(3)(iii)(B) of this section) by the maximum potential annual electricity generation (GWh), which is equal to the maximum rated electrical output of the unit (GW) times 8,760 hours. If the maximum rated electrical output value is expressed in units of MW, multiply it by 10^3 to convert it to GW; or

(*3*) If an EGU has a federally-enforceable permit limit on either the annual heat input or the number of annual operating hours, you may modify the calculations in paragraph (h)(3)(iii)(C)(1) of this section by replacing the maximum potential annual heat input or 8,760 unit operating hours with the permit limit on annual heat input or operating hours (as applicable).

(4) For a group of affected units that vent to a common stack, you may either assess LEE status for the units individually by performing a separate emission test of each unit in the duct leading from the unit to the common stack, or you may perform a single emission test in the common stack. If you choose the common stack testing option, the units in the configuration qualify for LEE status if:

(i) The emission rate measured at the common stack is less than 50 percent (10 percent for Hg) of the applicable emission limit in Table 1 or 2 to this subpart; or

(ii) For Hg from an existing EGU, the applicable Hg emission limit in Table 2 to this subpart is met and the potential annual mass emissions, calculated according to paragraph (h)(3)(iii) of this section (with some modifications), are less than or equal to 29.0 pounds times the number of units sharing the common stack. Base your calculations on the combined heat input capacity of all units sharing the stack (i.e., either the combined maximum rated value or, if applicable, a lower combined value restricted by permit conditions or operating hours).

(5) For an affected unit with a multiple stack or duct configuration in which the exhaust stacks or ducts are downstream of all emission control devices, you must perform a separate emission test in each stack or duct. The unit qualifies for LEE status if:

(i) The emission rate, based on all test runs performed at all of the stacks or ducts, is less than 50 percent (10 percent for Hg) of the applicable emission limit in Table 1 or 2 to this subpart; or

(ii) For Hg from an existing EGU, the applicable Hg emission limit in Table 2 to this subpart is met and the potential annual mass emissions, calculated according to paragraph (h)(3)(iii) of this section, are less than or equal to 29.0 pounds. Use the average Hg emission rate from paragraph (h)(5)(i) of this section in your calculations.

(i) Liquid-oil fuel moisture measurement. If your EGU combusts liquid fuels, if your fuel moisture content is no greater than 1.0 percent by weight, and if you would like to demonstrate initial and ongoing compliance with HCl and HF emissions limits, you must meet the requirements of paragraphs (i)(1) through (5) of this section.

(1) Measure fuel moisture content of each shipment of fuel if your fuel arrives on a batch basis; or

(2) Measure fuel moisture content daily if your fuel arrives on a continuous basis; or

(3) Obtain and maintain a fuel moisture certification from your fuel supplier.

(4) Use one of the following methods to determine fuel moisture content:

(i) ASTM D95–05 (Reapproved 2010), "Standard Test Method for Water in Petroleum Products and Bituminous Materials by Distillation," or

(ii) ASTM D4006–11, "Standard Test Method for Water in Crude Oil by Distillation," including Annex A1 and Appendix A1, or

(iii) ASTM D4177–95 (Reapproved 2010), "Standard Practice for Automatic Sampling of Petroleum and Petroleum Products," including Annexes A1 through A6 and Appendices X1 and X2, or

(iv) ASTM D4057–06 (Reapproved 2011), "Standard Practice for Manual Sampling of Petroleum and Petroleum Products," including Annex A1.

(5) Should the moisture in your liquid fuel be more than 1.0 percent by weight, you must

(i) Conduct HCl and HF emissions testing quarterly (and monitor site-specific operating parameters as provided in § 63.10000(c)(2)(iii) or

(ii) Use an HCl CEMS and/or HF CEMS.

(j) Startup and shutdown for coal-fired or solid oil derived-fired units. You must follow the requirements given in Table 3 to this subpart.

(k) You must submit a Notification of Compliance Status summarizing the results of your initial compliance demonstration, as provided in § 63.10030.

§ 63.10006 When must I conduct subsequent performance tests or tune-ups?

(a) For liquid oil-fired, solid oil-derived fuel- and coal-fired EGUs and IGCC units using PM CPMS to monitor continuous performance with an applicable emission limit as provided for under § 63.10000(c), you must conduct all applicable performance tests according to Table 5 to this subpart and § 63.10007 at least every year.

(b) For affected units meeting the LEE requirements of § 63.10005(h), you must repeat the performance test once every 3 years (once every year for Hg) according to Table 5 and § 63.10007. Should subsequent emissions testing results show the unit does not meet the LEE eligibility requirements, LEE status is lost. If this should occur:

(1) For all pollutant emission limits except for Hg, you must conduct emissions testing quarterly, except as otherwise provided in § 63.10021(d)(1).

(2) For Hg, you must install, certify, maintain, and operate a Hg CEMS or a sorbent trap monitoring system in accordance with appendix A to this subpart, within 6 calendar months of losing LEE eligibility. Until the Hg CEMS or sorbent trap monitoring system is installed, certified, and operating, you must conduct Hg emissions testing quarterly, except as otherwise provided in § 63.10021(d)(1). You must have 3 calendar years of testing and CEMS or

sorbent trap monitoring system data that satisfy the LEE emissions criteria to reestablish LEE status.

(c) Except where paragraphs (a) or (b) of this section apply, or where you install, certify, and operate a PM CEMS to demonstrate compliance with a filterable PM emission limit, for liquid oil-fired EGUs, you must conduct all applicable periodic emissions tests for filterable PM, or individual or total HAP metals emissions according to Table 5 to this subpart and § 63.10007 at least quarterly, except as otherwise provided in § 63.10021(d)(1).

(d) Except where paragraph (b) of this section applies, for solid oil-derived fuel- and coal-fired EGUs that do not use either an HCl CEMS to monitor compliance with the HCl limit or an SO_2 CEMS to monitor compliance with the alternate equivalent SO_2 emission limit, you must conduct all applicable periodic HCl emissions tests according to Table 5 to this subpart and § 63.10007 at least quarterly, except as otherwise provided in § 63.10021(d)(1).

(e) Except where paragraph (b) of this section applies, for liquid oil-fired EGUs without HCl CEMS, HF CEMS, or HCl and HF CEMS, you must conduct all applicable emissions tests for HCl, HF, or HCl and HF emissions according to Table 5 to this subpart and § 63.10007 at least quarterly, except as otherwise provided in § 63.10021(d)(1), and conduct site-specific monitoring under a plan as provided for in § 63.10000(c)(2)(iii).

(f) Unless you follow the requirements listed in paragraphs (g) and (h) of this section, performance tests required at least every 3 calendar years must be completed within 35 to 37 calendar months after the previous performance test; performance tests required at least every year must be completed within 11 to 13 calendar months after the previous performance test; and performance tests required at least quarterly must be completed within 80 to 100 calendar days after the previous performance test, except as otherwise provided in § 63.10021(d)(1).

(g) If you elect to demonstrate compliance using emissions averaging under § 63.10009, you must continue to conduct performance stack tests at the appropriate frequency given in section (c) through (f) of this section.

(h) If a performance test on a non-mercury LEE shows emissions in excess of 50 percent of the emission limit and if you choose to reapply for LEE status, you must conduct performance tests at the appropriate frequency given in section (c) through (e) of this section for that pollutant until all performance tests over a consecutive 3-year period show compliance with the LEE criteria.

(i) If you are required to meet an applicable tune-up work practice standard, you must conduct a performance tune-up according to § 63.10021(e).

(1) For EGUs not employing neural network combustion optimization during normal operation, each performance tune-up specified in § 63.10021(e) must be no more than 36 calendar months after the previous performance tune-up.

(2) For EGUs employing neural network combustion optimization systems during normal operation, each performance tune-up specified in § 63.10021(e) must be no more than 48 calendar months after the previous performance tune-up.

(j) You must report the results of performance tests and performance tune-ups within 60 days after the completion of the performance tests and performance tune-ups. The reports for all subsequent performance tests must include all applicable information required in § 63.10031.

§ 63.10007 What methods and other procedures must I use for the performance tests?

(a) Except as otherwise provided in this section, you must conduct all required performance tests according to § 63.7(d), (e), (f), and (h). You must also develop a site-specific test plan according to the requirements in § 63.7(c).

(1) If you use CEMS (Hg, HCl, SO_2, or other) to determine compliance with a 30-boiler operating day rolling average emission limit, you must collect data for all nonexempt unit operating conditions (see § 63.10011(g) and Table 3 to this subpart).

(2) If you conduct performance testing with test methods in lieu of continuous monitoring, operate the unit at maximum normal operating load conditions during each periodic (*e.g.*, quarterly) performance test. Maximum normal operating load will be generally between 90 and 110 percent of design capacity but should be representative of site specific normal operations during each test run.

(3) For establishing operating limits with particulate matter continuous parametric monitoring system (PM CPMS) to demonstrate compliance with a PM or non Hg metals emissions limit, operate the unit at maximum normal operating load conditions during the performance test period. Maximum normal operating load will be generally between 90 and 110 percent of design capacity but should be representative of site specific normal operations during each test run.

(b) You must conduct each performance test (including traditional 3-run stack tests, 30-boiler operating day tests based on CEMS data (or sorbent trap monitoring system data), and 30-boiler operating day Hg emission tests for LEE qualification) according to the requirements in Table 5 to this subpart.

(c) If you choose to comply with the filterable PM emission limit and demonstrate continuous performance using a PM CPMS for an applicable emission limit as provided for in § 63.10000(c), you must also establish an operating limit according to § 63.10011(b)(5) and Tables 4 and 6 to this subpart. Should you desire to have operating limits that correspond to loads other than maximum normal operating load, you must conduct testing at those other loads to determine the additional operating limits.

(d) Except for a 30-boiler operating day performance test based on CEMS (or sorbent trap monitoring system) data, where the concept of test runs does not apply, you must conduct a minimum of three separate test runs for each performance test, as specified in § 63.7(e)(3). Each test run must comply with the minimum applicable sampling time or volume specified in Table 1 or 2 to this subpart. Sections 63.10005(d) and (h), respectively, provide special instructions for conducting performance tests based on CEMS or sorbent trap monitoring systems, and for conducting emission tests for LEE qualification.

(e) To use the results of performance testing to determine compliance with the applicable emission limits in Table 1 or 2 to this subpart, proceed as follows:

(1) Except for a 30-boiler operating day performance test based on CEMS (or sorbent trap monitoring system) data, if measurement results for any pollutant are reported as below the method detection level (*e.g.*, laboratory analytical results for one or more sample components are below the method defined analytical detection level), you must use the method detection level as the measured emissions level for that pollutant in calculating compliance. The measured result for a multiple component analysis (*e.g.*, analytical values for multiple Method 29 fractions both for individual HAP metals and for total HAP metals) may include a combination of method detection level data and analytical data reported above the method detection level.

(2) If the limits are expressed in lb/MMBtu or lb/TBtu, you must use the F-factor methodology and equations in

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sections 12.2 and 12.3 of EPA Method 19 in appendix A–7 to part 60 of this chapter. In cases where an appropriate F-factor is not listed in Table 19–2 of Method 19, you may use F-factors from Table 1 in section 3.3.5 of appendix F to part 75 of this chapter, or F-factors derived using the procedures in section 3.3.6 of appendix to part 75 of this chapter. Use the following factors to convert the pollutant concentrations measured during the initial performance tests to units of lb/scf, for use in the applicable Method 19 equations:

(i) Multiply SO_2 ppm by 1.66×10^{-7};

(ii) Multiply HCl ppm by 9.43×10^{-8};

(iii) Multiply HF ppm by 5.18×10^{-8};

(iv) Multiply HAP metals concentrations (mg/dscm) by 6.24×10^{-8}; and

(v) Multiply Hg concentrations (μg/scm) by 6.24×10^{-11}.

(3) To determine compliance with emission limits expressed in lb/MWh or lb/GWh, you must first calculate the pollutant mass emission rate during the performance test, in units of lb/h. For Hg, if a CEMS or sorbent trap monitoring system is used, use Equation A–2 or A–3 in appendix A to this subpart (as applicable). In all other cases, use an equation that has the general form of Equation A–2 or A–3, replacing the value of K with 1.66×10^{-7} lb/scf-ppm for SO_2, 9.43×10^{-8} lb/scf-ppm for HCl (if an HCl CEMS is used), 5.18×10^{-8} lb/scf-ppm for HF (if an HF CEMS is used), or 6.24×10^{-8} lb-scm/mg-scf for HAP metals and for HCl and HF (when performance stack testing is used), and defining C_h as the average SO_2, HCl, or HF concentration in ppm, or the average HAP metals concentration in mg/dscm. This calculation requires stack gas volumetric flow rate (scfh) and (in some cases) moisture content data (see §§ 63.10005(h)(3) and 63.10010). Then, if the applicable emission limit is in units of lb/GWh, use Equation A–4 in appendix A to this subpart to calculate the pollutant emission rate in lb/GWh. In this calculation, define $(M)_h$ as the calculated pollutant mass emission rate for the performance test (lb/h), and define $(MW)_h$ as the average electrical load during the performance test (megawatts). If the applicable emission limit is in lb/MWh rather than lb/GWh, omit the 10^3 term from Equation A–4 to determine the pollutant emission rate in lb/MWh.

(f) Upon request, you shall make available to the EPA Administrator such records as may be necessary to determine whether the performance tests have been done according to the requirements of this section.

§ 63.10008 [Reserved]

§ 63.10009 May I use emissions averaging to comply with this subpart?

(a) *General eligibility.* (1) You may use emissions averaging as described in paragraph (a)(2) of this section as an alternative to meeting the requirements of § 63.9991 for filterable PM, SO_2, HF, HCl, non-Hg HAP metals, or Hg on an EGU-specific basis if:

(i) You have more than one existing EGU in the same subcategory located at one or more contiguous properties, belonging to a single major industrial grouping, which are under common control of the same person (or persons under common control); and

(ii) You use CEMS (or sorbent trap monitoring systems for determining Hg emissions) or quarterly emissions testing for demonstrating compliance.

(2) You may demonstrate compliance by emissions averaging among the existing EGUs in the same subcategory, if your averaged Hg emissions for EGUs in the "unit designed for coal ≥ 8,300 Btu/lb" subcategory are equal to or less than 1.0 lb/TBtu or 1.1E–2 lb/GWh or if your averaged emissions of individual, other pollutants from other subcategories of such EGUs are equal to or less than the applicable emissions limit in Table 2, according to the procedures in this section. Note that except for Hg emissions from EGUs in the "unit designed for coal ≥ 8,300 Btu/lb" subcategory, the averaging time for emissions averaging for pollutants is 30 days (rolling daily) using data from CEMS or a combination of data from CEMS and manual performance testing. The averaging time for emissions averaging for Hg from EGUs in the "unit designed for coal ≥ 8,300 Btu/lb" subcategory is 90 days (rolling daily) using data from CEMS, sorbent trap monitoring, or a combination of monitoring data and data from manual performance testing. For the purposes of this paragraph, 30- (or 90-day) group boiler operating days is defined as a period during which at least one unit in the emissions averaging group has operated 30 (or 90) days. You must calculate the weighted average emissions rate for the group in accordance with the procedures in this paragraph using the data from all units in the group including any that operate fewer than 30 (or 90) days during the preceding 30 (or 90) group boiler days.

(i) You may choose to have your EGU emissions averaging group meet either the heat input basis (MMBtu or TBtu, as appropriate for the pollutant) or gross electrical output basis (MWh or GWh, as appropriate for the pollutant).

(ii) You may not mix bases within your EGU emissions averaging group.

(iii) You may use emissions averaging for affected units in different subcategories if the units vent to the atmosphere through a common stack (see paragraph (m) of this section).

(b) *Equations.* Use the following equations when performing calculations for your EGU emissions averaging group:

(1) *Group eligibility equations.*

$$WAERm = \frac{\left[\sum_{i=1}^{p}\left[\sum_{i=1}^{n}(Herm_i \times Rmm_i)\right]_p\right] + \sum_{i=1}^{m}(Ter_i \times Rmt_i)}{\left[\sum_{i=1}^{p}\left[\sum_{i=1}^{n} Rmm_i\right]_p\right] + \sum_{i=1}^{m} Rmt_i} \quad (Eq.\ 1a)$$

Where:

WAERm = Weighted average emissions rate maximum in terms of lb/heat input or lb/gross electrical output,

$Herm_i$ = Hourly emissions rate (*e.g.*, lb/MMBtu, lb/MWh) from CEMS or sorbent trap monitoring for hour i,

Rmm_i = Maximum rated heat input or gross electrical output of unit i in terms of heat input or gross electrical output,

p = number of EGUs in emissions averaging group that rely on CEMS,

n = number of hourly rates collected over 30-group boiler operating days,

Ter_i = Emissions rate from most recent test of unit i in terms of lb/heat input or lb/gross electrical output,

Rmt_i = Maximum rated heat input or gross electrical output of unit i in terms of lb/heat input or lb/gross electrical output, and

m = number of EGUs in emissions averaging group that rely on emissions testing.

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$$WAERm = \frac{[\sum_{i=1}^{p}[\sum_{i=1}^{n}(Herm_i \times Smm_i \times Cfm_i)]_p] + \sum_{i=1}^{m}(Ter_i \times Smt_i \times Cft_i)}{[\sum_{i=1}^{p}[\sum_{i=1}^{n} Smm_i \times Cfm_i]_p] + \sum_{i=1}^{m} Smt_i \times Cft_i} \quad (Eq.\ 1b)$$

Where:

variables with similar names share the descriptions for Equation 1a,

Smm_i = maximum steam generation in units of pounds from unit i that uses CEMS or sorbent trap monitoring,

Cfm_i = conversion factor, calculated from the most recent emissions test results, in units of heat input per pound of steam generated or gross electrical output per pound of steam generated, from unit i that uses CEMS or sorbent trap monitoring,

Smt_i = maximum steam generation in units of pounds from unit i that uses emissions testing, and

Cft_i = conversion factor, calculated from the most recent emissions test results, in units of heat input per pound of steam generated or gross electrical output per pound of steam generated, from unit i that uses emissions testing.

(2) Weighted 30-day rolling average emissions rate equations for pollutants other than Hg. Use equation 2a or 2b to calculate the 30-day rolling average emissions daily.

$$WAER = \frac{\sum_{i=1}^{p}[\sum_{i=1}^{n}(Her_i \times Rm_i)]_p + \sum_{i=1}^{m}(Ter_i \times Rt_i)}{\sum_{i=1}^{p}[\sum_{i=1}^{n}(Rm_i)]_p + \sum_{i=1}^{m} Rt_i} \quad (Eq.\ 2a)$$

Where:

Her_i = hourly emission rate (*e.g.*, lb/MMBtu, lb/MWh) from unit i's CEMS for the preceding 30-group boiler operating days,

Rm_i = hourly heat input or gross electrical output from unit i for the preceding 30-group boiler operating days,

p = number of EGUs in emissions averaging group that rely on CEMS or sorbent trap monitoring,

n = number of hourly rates collected over 30-group boiler operating days,

Ter_i = Emissions rate from most recent emissions test of unit i in terms of lb/heat input or lb/gross electrical output,

Rt_i = Maximum rated heat input or gross electrical output of unit i in terms of lb/heat input or lb/gross electrical output, and

m = number of EGUs in emissions averaging group that rely on emissions testing.

$$WAER = \frac{\sum_{i=1}^{p}[\sum_{i=1}^{n}(Her_i \times Sm_i \times Cfm_i)]_p + \sum_{i=1}^{m}(Ter_i \times St_i \times Cft_i)}{\sum_{i=1}^{p}[\sum_{i=1}^{n}(Sm_i \times Cfm_i)]_p + \sum_{i=1}^{m} St_i \times Cft_i} \quad (Eq.\ 2b)$$

Where:

variables with similar names share the descriptions for Equation 2a,

Sm_i = steam generation in units of pounds from unit i that uses CEMS for the preceding 30-group boiler operating days,

Cfm_i = conversion factor, calculated from the most recent compliance test results, in units of heat input per pound of steam generated or gross electrical output per pound of steam generated, from unit i that uses CEMS from the preceding 30-group boiler operating days,

St_i = steam generation in units of pounds from unit i that uses emissions testing, and

Cft_i = conversion factor, calculated from the most recent compliance test results, in units of heat input per pound of steam generated or gross electrical output per pound of steam generated, from unit i that uses emissions testing.

(3) Weighted 90-boiler operating day rolling average emissions rate equations for Hg emissions from EGUs in the "unit designed for coal ≥ 8,300 Btu/lb" subcategory. Use equation 3a or 3b to calculate the 90-day rolling average emissions daily.

$$WAER = \frac{\sum_{i=1}^{p}[\sum_{i=1}^{n}(Her_i \times Rm_i)]_p + \sum_{i=1}^{m}(Ter_i \times Rt_i)}{\sum_{i=1}^{p}[\sum_{i=1}^{n}(Rm_i)]_p + \sum_{i=1}^{m} Rt_i} \quad (Eq.\ 3a)$$

Where:

Her_i = hourly emission rate from unit i's CEMS or Hg sorbent trap monitoring for the preceding 90-group boiler operating days,

Rm_i = hourly heat input or gross electrical output from unit i for the preceding 90-group boiler operating days,

p = number of EGUs in emissions averaging group that rely on CEMS,

n = number of hourly rates collected over the 90-group boiler operating days,

Ter_i = Emissions rate from most recent emissions test of unit i in terms of lb/heat input or lb/gross electrical output,

Rt_i = Maximum rated heat input or gross electrical output of unit i in terms of lb/heat input or lb/gross electrical output, and

m = number of EGUs in emissions averaging group that rely on emissions testing.

$$WAER = \frac{\sum_{i=1}^{p}[\sum_{i=1}^{n}(Her_i \times Sm_i \times Cfm_i)]_p + \sum_{i=1}^{m}(Ter_i \times St_i \times Cft_i)}{\sum_{i=1}^{p}[\sum_{i=1}^{n}(Sm_i \times Cfm_i)]_p + \sum_{i=1}^{m} St_i \times Cft_i} \quad (Eq.\ 3b)$$

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Where:

variables with similar names share the descriptions for Equation 2a,

Sm_i = steam generation in units of pounds from unit i that uses CEMS or a Hg sorbent trap monitoring for the preceding 90-group boiler operating days,

Cfm_i = conversion factor, calculated from the most recent compliance test results, in units of heat input per pound of steam generated or gross electrical output per pound of steam generated, from unit i that uses CEMS or sorbent trap monitoring from the preceding 90-group boiler operating days,

St_i = steam generation in units of pounds from unit i that uses emissions testing, and

Cft_i = conversion factor, calculated from the most recent emissions test results, in units of heat input per pound of steam generated or gross electrical output per pound of steam generated, from unit i that uses emissions testing.

(c) *Separate stack requirements.* For a group of two or more existing EGUs in the same subcategory that each vent to a separate stack, you may average filterable PM, SO_2, HF, HCl, non-Hg HAP metals, or Hg emissions to demonstrate compliance with the limits in Table 2 to this subpart if you satisfy the requirements in paragraphs (d) through (j) of this section.

(d) For each existing EGU in the averaging group:

(1) The emissions rate achieved during the initial performance test for the HAP being averaged must not exceed the emissions level that was being achieved 180 days after April 16, 2015, or the date on which emissions testing done to support your emissions averaging plan is complete (if the Administrator does not require submission and approval of your emissions averaging plan), or the date that you begin emissions averaging, whichever is earlier; or

(2) The control technology employed during the initial performance test must not be less than the design efficiency of the emissions control technology employed 180 days after April 16, 2015 or the date that you begin emissions averaging, whichever is earlier.

(e) The weighted-average emissions rate from the existing EGUs participating in the emissions averaging option must be in compliance with the limits in Table 2 to this subpart at all times following the compliance date specified 180 days after April 16, 2015, or the date on which you complete the emissions measurements used to support your emissions averaging plan (if the Administrator does not require submission and approval of your emissions averaging plan), or the date that you begin emissions averaging, whichever is earlier.

(f) Emissions averaging group eligibility demonstration. You must demonstrate the ability for the EGUs included in the emissions averaging group to demonstrate initial compliance according to paragraph (f)(1) or (2) of this section using the maximum normal operating load of each EGU and the results of the initial performance tests. For this demonstration and prior to submitting your emissions averaging plan, if requested, you must conduct required emissions monitoring for 30 days of boiler operation and any required manual performance testing to calculate an initial weighted average emissions rate in accordance with this section. Should the Administrator require approval, you must submit your proposed emissions averaging plan and supporting data at least 120 days before April 16, 2015. If the Administrator requires approval of your plan, you may not begin using emissions averaging until the Administrator approves your plan.

(1) You must use Equation 1a in paragraph (b) of this section to demonstrate that the maximum weighted average emissions rates of filterable PM, HF, SO_2, HCl, non-Hg HAP metals, or Hg emissions from the existing units participating in the emissions averaging option do not exceed the emissions limits in Table 2 to this subpart.

(2) If you are not capable of monitoring heat input or gross electrical output, and the EGU generates steam for purposes other than generating electricity, you may use Equation 1b of this section as an alternative to using Equation 1a of this section to demonstrate that the maximum weighted average emissions rates of filterable PM, HF, SO_2, HCl, non-Hg HAP metals, or Hg emissions from the existing units participating in the emissions averaging group do not exceed the emission limits in Table 2 to this subpart.

(g) You must determine the weighted average emissions rate in units of the applicable emissions limit on a 30 day rolling average (90 day rolling average for Hg) basis according to paragraphs (f)(1) through (3) of this section. The first averaging period begins on 30 (or 90 for Hg) days after February 16, 2015 or the date that you begin emissions averaging, whichever is earlier.

(1) You must use Equation 2a or 3a of paragraph (b) of this section to calculate the weighted average emissions rate using the actual heat input or gross electrical output for each existing unit participating in the emissions averaging option.

(2) If you are not capable of monitoring heat input or gross electrical output, you may use Equation 2b or 3b of paragraph (b) of this section as an alternative to using Equation 2a of paragraph (b) of this section to calculate the average weighted emission rate using the actual steam generation from the units participating in the emissions averaging option.

(h) *CEMS (or sorbent trap monitoring) use.* If an EGU in your emissions averaging group uses CEMS (or a sorbent trap monitor for Hg emissions) to demonstrate compliance, you must use those data to determine the 30 (or 90) group boiler operating day rolling average emissions rate.

(i) *Emissions testing.* If you use manual emissions testing to demonstrate compliance for one or more EGUs in your emissions averaging group, you must use the results from the most recent performance test to determine the 30 (or 90) day rolling average. You may use CEMS or sorbent trap data in combination with data from the most recent manual performance test in calculating the 30 (or 90) group boiler operating day rolling average emissions rate.

(j) *Emissions averaging plan.* You must develop an implementation plan for emissions averaging according to the following procedures and requirements in paragraphs (j)(1) and (2) of this section.

(1) You must include the information contained in paragraphs (j)(1)(i) through (v) of this section in your implementation plan for all the emissions units included in an emissions averaging:

(i) The identification of all existing EGUs in the emissions averaging group, including for each either the applicable HAP emission level or the control technology installed as of 180 days after February 16, 2015, or the date on which you complete the emissions measurements used to support your emissions averaging plan (if the Administrator does not require submission and approval of your emissions averaging plan), or the date that you begin emissions averaging, whichever is earlier; and the date on which you are requesting emissions averaging to commence;

(ii) The process weighting parameter (heat input, gross electrical output, or steam generated) that will be monitored for each averaging group;

(iii) The specific control technology or pollution prevention measure to be used for each emission EGU in the averaging group and the date of its installation or application. If the pollution prevention measure reduces or eliminates

emissions from multiple EGUs, you must identify each EGU;

(iv) The means of measurement (*e.g.*, CEMS, sorbent trap monitoring, manual performance test) of filterable PM, SO_2, HF, HCl, individual or total non-Hg HAP metals, or Hg emissions in accordance with the requirements in § 63.10007 and to be used in the emissions averaging calculations; and

(v) A demonstration that emissions averaging can produce compliance with each of the applicable emission limit(s) in accordance with paragraph (b)(1) of this section.

(2) If the Administrator requests you to submit the plan for review and approval, you must submit a complete implementation plan at least 120 days before April 16, 2015. If the Administrator requests you to submit the plan for review and approval, you must receive approval before initiating emissions averaging.

(i) The Administrator shall use following criteria in reviewing and approving or disapproving the plan:

(A) Whether the content of the plan includes all of the information specified in paragraph (h)(1) of this section; and

(B) Whether the plan presents information sufficient to determine that compliance will be achieved and maintained.

(ii) The Administrator shall not approve an emissions averaging implementation plan containing any of the following provisions:

(A) Any averaging between emissions of different pollutants or between units located at different facilities; or

(B) The inclusion of any emissions unit other than an existing unit in the same subcategory.

(k) *Common stack requirements.* For a group of two or more existing affected units, each of which vents through a single common stack, you may average emissions to demonstrate compliance with the limits in Table 2 to this subpart if you satisfy the requirements in paragraph (l) or (m) of this section.

(l) For a group of two or more existing units in the same subcategory and which vent through a common emissions control system to a common stack that does not receive emissions from units in other subcategories or categories, you may treat such averaging group as a single existing unit for purposes of this subpart and comply with the requirements of this subpart as if the group were a single unit.

(m) For all other groups of units subject to paragraph (k) of this section, you may elect to conduct manual performance tests according to procedures specified in § 63.10007 in the common stack. If emissions from affected units included in the emissions averaging and from other units not included in the emissions averaging (*e.g.*, in a different subcategory) or other nonaffected units all vent to the common stack, you must shut down the units not included in the emissions averaging and the nonaffected units or vent their emissions to a different stack during the performance test. Alternatively, you may conduct a performance test of the combined emissions in the common stack with all units operating and show that the combined emissions meet the most stringent emissions limit. You may also use a CEMS or sorbent trap monitoring to apply this latter alternative to demonstrate that the combined emissions comply with the most stringent emissions limit on a continuous basis.

(n) Combination requirements. The common stack of a group of two or more existing EGUs in the same subcategory subject to paragraph (k) of this section may be treated as a single stack for purposes of paragraph (c) of this section and included in an emissions averaging group subject to paragraph (c) of this section.

§ 63.10010 What are my monitoring, installation, operation, and maintenance requirements?

(a) Flue gases from the affected units under this subpart exhaust to the atmosphere through a variety of different configurations, including but not limited to individual stacks, a common stack configuration or a main stack plus a bypass stack. For the CEMS, PM CPMS, and sorbent trap monitoring systems used to provide data under this subpart, the continuous monitoring system installation requirements for these exhaust configurations are as follows:

(1) *Single unit-single stack configurations.* For an affected unit that exhausts to the atmosphere through a single, dedicated stack, you shall either install the required CEMS, PM CPMS, and sorbent trap monitoring systems in the stack or at a location in the ductwork downstream of all emissions control devices, where the pollutant and diluents concentrations are representative of the emissions that exit to the atmosphere.

(2) *Unit utilizing common stack with other affected unit(s).* When an affected unit utilizes a common stack with one or more other affected units, but no non-affected units, you shall either:

(i) Install the required CEMS, PM CPMS, and sorbent trap monitoring systems in the duct leading to the common stack from each unit; or

(ii) Install the required CEMS, PM CPMS, and sorbent trap monitoring systems in the common stack.

(3) *Unit(s) utilizing common stack with non-affected unit(s).*

(i) When one or more affected units shares a common stack with one or more non-affected units, you shall either:

(A) Install the required CEMS, PM CPMS, and sorbent trap monitoring systems in the ducts leading to the common stack from each affected unit; or

(B) Install the required CEMS, PM CPMS, and sorbent trap monitoring systems described in this section in the common stack and attribute all of the emissions measured at the common stack to the affected unit(s).

(ii) If you choose the common stack monitoring option:

(A) For each hour in which valid data are obtained for all parameters, you must calculate the pollutant emission rate and

(B) You must assign the calculated pollutant emission rate to each unit that shares the common stack.

(4) *Unit with a main stack and a bypass stack.* If the exhaust configuration of an affected unit consists of a main stack and a bypass stack, you shall install CEMS on both the main stack and the bypass stack, or, if it is not feasible to certify and quality-assure the data from a monitoring system on the bypass stack, you shall install a CEMS only on the main stack and count bypass hours of deviation from the monitoring requirements.

(5) *Unit with a common control device with multiple stack or duct configuration.* If the flue gases from an affected unit, which is configured such that emissions are controlled with a common control device or series of control devices, are discharged to the atmosphere through more than one stack or are fed into a single stack through two or more ducts, you may:

(i) Install required CEMS, PM CPMS, and sorbent trap monitoring systems in each of the multiple stacks;

(ii) Install required CEMS, PM CPMS, and sorbent trap monitoring systems in each of the ducts that feed into the stack;

(iii) Install required CEMS, PM CPMS, and sorbent trap monitoring systems in one of the multiple stacks or ducts and monitor the flows and dilution rates in all multiple stacks or ducts in order to determine total exhaust gas flow rate and pollutant mass emissions rate in accordance with the applicable limit; or

(iv) In the case of multiple ducts feeding into a single stack, install CEMS, PM CPMS, and sorbent trap

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monitoring systems in the single stack as described in paragraph (a)(1) of this section.

(6) *Unit with multiple parallel control devices with multiple stacks.* If the flue gases from an affected unit, which is configured such that emissions are controlled with multiple parallel control devices or multiple series of control devices are discharged to the atmosphere through more than one stack, you shall install the required CEMS, PM CPMS, and sorbent trap monitoring systems described in each of the multiple stacks. You shall calculate hourly flow-weighted average pollutant emission rates for the unit as follows:

(i) Calculate the pollutant emission rate at each stack or duct for each hour in which valid data are obtained for all parameters;

(ii) Multiply each calculated hourly pollutant emission rate at each stack or duct by the corresponding hourly stack gas flow rate at that stack or duct;

(iii) Sum the products determined under paragraph (a)(5)(iii)(B) of this section; and

(iv) Divide the result obtained in paragraph (a)(5)(iii)(C) of this section by the total hourly stack gas flow rate for the unit, summed across all of the stacks or ducts.

(b) If you use an oxygen (O_2) or carbon dioxide (CO_2) CEMS to convert measured pollutant concentrations to the units of the applicable emissions limit, the O_2 or CO_2 concentrations shall be monitored at a location that represents emissions to the atmosphere, *i.e.,* at the outlet of the EGU, downstream of all emission control devices. You must install, certify, maintain, and operate the CEMS according to part 75 of this chapter. Use only quality-assured O_2 or CO_2 data in the emissions calculations; do not use part 75 substitute data values.

(c) If you are required to use a stack gas flow rate monitor, either for routine operation of a sorbent trap monitoring system or to convert pollutant concentrations to units of an electrical output-based emission standard in Table 1 or 2 to this subpart, you must install, certify, operate, and maintain the monitoring system and conduct on-going quality-assurance testing of the system according to part 75 of this chapter. Use only unadjusted, quality-assured flow rate data in the emissions calculations. Do not apply bias adjustment factors to the flow rate data and do not use substitute flow rate data in the calculations.

(d) If you are required to make corrections for stack gas moisture content when converting pollutant concentrations to the units of an emission standard in Table 1 of 2 to this subpart, you must install, certify, operate, and maintain a moisture monitoring system in accordance with part 75 of this chapter. Alternatively, for coal-fired units, you may use appropriate fuel-specific default moisture values from § 75.11(b) of this chapter to estimate the moisture content of the stack gas or you may petition the Administrator under § 75.66 of this chapter for use of a default moisture value for non-coal-fired units. If you install and operate a moisture monitoring system, do not use substitute moisture data in the emissions calculations.

(e) If you use an HCl and/or HF CEMS, you must install, certify, operate, maintain, and quality-assure the data from the monitoring system in accordance with appendix B to this subpart. Calculate and record a 30-boiler operating day rolling average HCl or HF emission rate in the units of the standard, updated after each new boiler operating day. Each 30-boiler operating day rolling average emission rate is the average of all the valid hourly HCl or HF emission rates in the preceding 30 boiler operating days (see section 9.4 of appendix B to this subpart).

(f)(1) If you use an SO_2 CEMS, you must install the monitor at the outlet of the EGU, downstream of all emission control devices, and you must certify, operate, and maintain the CEMS according to part 75 of this chapter.

(2) For on-going QA, the SO_2 CEMS must meet the applicable daily, quarterly, and semiannual or annual requirements in sections 2.1 through 2.3 of appendix B to part 75 of this chapter, with the following addition: You must perform the linearity checks required in section 2.2 of appendix B to part 75 of this chapter if the SO_2 CEMS has a span value of 30 ppm or less.

(3) Calculate and record a 30-boiler operating day rolling average SO_2 emission rate in the units of the standard, updated after each new boiler operating day. Each 30-boiler operating day rolling average emission rate is the average of all of the valid SO_2 emission rates in the preceding 30 boiler operating days.

(4) Use only unadjusted, quality-assured SO_2 concentration values in the emissions calculations; do not apply bias adjustment factors to the part 75 SO_2 data and do not use part 75 substitute data values.

(g) If you use a Hg CEMS or a sorbent trap monitoring system, you must install, certify, operate, maintain and quality-assure the data from the monitoring system in accordance with appendix A to this subpart. You must calculate and record a 30-boiler operating day rolling average Hg emission rate, in units of the standard, updated after each new boiler operating day. Each 30-boiler operating day rolling average emission rate, calculated according to section 6.2 of appendix A to the subpart, is the average of all of the valid hourly Hg emission rates in the preceding 30 boiler operating days. Section 7.1.4.3 of appendix A to this subpart explains how to reduce sorbent trap monitoring system data to an hourly basis.

(h) If you use a PM CPMS to demonstrate continuous compliance with an operating limit, you must install, calibrate, maintain, and operate the PM CPMS and record the output of the system as specified in paragraphs (h)(1) through (5) of this section.

(1) Install, calibrate, operate, and maintain your PM CPMS according to the procedures in your approved site-specific monitoring plan developed in accordance with § 63.10000(d), and meet the requirements in paragraphs (h)(1)(i) through (iii) of this section.

(i) The operating principle of the PM CPMS must be based on in-stack or extractive light scatter, light scintillation, beta attenuation, or mass accumulation detection of the exhaust gas or representative sample. The reportable measurement output from the PM CPMS may be expressed as milliamps, stack concentration, or other raw data signal.

(ii) The PM CPMS must have a cycle time (*i.e.,* period required to complete sampling, measurement, and reporting for each measurement) no longer than 60 minutes.

(iii) The PM CPMS must be capable, at a minimum, of detecting and responding to particulate matter concentrations of 0.5 mg/acm.

(2) For a new unit, complete the initial PM CPMS performance evaluation no later than October 13, 2012 or 180 days after the date of initial startup, whichever is later. For an existing unit, complete the initial performance evaluation no later than October 13, 2015.

(3) Collect PM CPMS hourly average output data for all boiler operating hours except as indicated in paragraph (h)(5) of this section. Express the PM CPMS output as milliamps, PM concentration, or other raw data signal value.

(4) Calculate the arithmetic 30-boiler operating day rolling average of all of the hourly average PM CPMS output collected during all nonexempt boiler operating hours data (*e.g.,* milliamps, PM concentration, raw data signal).

(5) You must collect data using the PM CPMS at all times the process unit is operating and at the intervals specified in paragraph (h)(1)(ii) of this section, except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, required monitoring system quality assurance or quality control activities (including, as applicable, calibration checks and required zero and span adjustments), and any scheduled maintenance as defined in your site-specific monitoring plan.

(6) You must use all the data collected during all boiler operating hours in assessing the compliance with your operating limit except:

(i) Any data collected during monitoring system malfunctions, repairs associated with monitoring system malfunctions, or required monitoring system quality assurance or quality control activities conducted during monitoring system malfunctions are not used in calculations (report any such periods in your annual deviation report);

(ii) Any data collected during periods when the monitoring system is out of control as specified in your site-specific monitoring plan, repairs associated with periods when the monitoring system is out of control, or required monitoring system quality assurance or quality control activities conducted during out-of-control periods are not used in calculations (report emissions or operating levels and report any such periods in your annual deviation report);

(iii) Any data recorded during periods of startup or shutdown.

(7) You must record and make available upon request results of PM CPMS system performance audits, as well as the dates and duration of periods from when the PM CPMS is out of control until completion of the corrective actions necessary to return the PM CPMS to operation consistent with your site-specific monitoring plan.

(i) If you choose to comply with the PM filterable emissions limit in lieu of metal HAP limits, you may choose to install, certify, operate, and maintain a PM CEMS and record the output of the PM CEMS as specified in paragraphs (i)(1) through (5) of this section. The compliance limit will be expressed as a 30-boiler operating day rolling average of the numerical emissions limit value applicable for your unit in tables 1 or 2 to this subpart.

(1) Install and certify your PM CEMS according to the procedures and requirements in Performance Specification 11—Specifications and Test Procedures for Particulate Matter Continuous Emission Monitoring Systems at Stationary Sources in Appendix B to part 60 of this chapter, using Method 5 at Appendix A–3 to part 60 of this chapter and ensuring that the front half filter temperature shall be 160° ± 14°C (320° ± 25°F). The reportable measurement output from the PM CEMS must be expressed in units of the applicable emissions limit (*e.g.*, lb/MMBtu, lb/MWh).

(2) Operate and maintain your PM CEMS according to the procedures and requirements in Procedure 2—Quality Assurance Requirements for Particulate Matter Continuous Emission Monitoring Systems at Stationary Sources in Appendix F to part 60 of this chapter.

(i) You must conduct the relative response audit (RRA) for your PM CEMS at least once annually.

(ii) You must conduct the relative correlation audit (RCA) for your PM CEMS at least once every 3 years.

(3) Collect PM CEMS hourly average output data for all boiler operating hours except as indicated in paragraph (i) of this section.

(4) Calculate the arithmetic 30-boiler operating day rolling average of all of the hourly average PM CEMS output data collected during all nonexempt boiler operating hours.

(5) You must collect data using the PM CEMS at all times the process unit is operating and at the intervals specified in paragraph (a) of this section, except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, and required monitoring system quality assurance or quality control activities.

(i) You must use all the data collected during all boiler operating hours in assessing the compliance with your operating limit except:

(A) Any data collected during monitoring system malfunctions, repairs associated with monitoring system malfunctions, or required monitoring system quality assurance or control activities conducted during monitoring system malfunctions in calculations and report any such periods in your annual deviation report;

(B) Any data collected during periods when the monitoring system is out of control as specified in your site-specific monitoring plan, repairs associated with periods when the monitoring system is out of control, or required monitoring system quality assurance or control activities conducted during out of control periods in calculations used to report emissions or operating levels and report any such periods in your annual deviation report;

(C) Any data recorded during periods of startup or shutdown.

(ii) You must record and make available upon request results of PM CEMS system performance audits, dates and duration of periods when the PM CEMS is out of control to completion of the corrective actions necessary to return the PM CEMS to operation consistent with your site-specific monitoring plan.

(j) You may choose to comply with the metal HAP emissions limits using CEMS approved in accordance with § 63.7(f) as an alternative to the performance test method specified in this rule. If approved to use a HAP metals CEMS, the compliance limit will be expressed as a 30-boiler operating day rolling average of the numerical emissions limit value applicable for your unit in tables 1 or 2. If approved, you may choose to install, certify, operate, and maintain a HAP metals CEMS and record the output of the HAP metals CEMS as specified in paragraphs (j)(1) through (5) of this section.

(1)(i) Install and certify your HAP metals CEMS according to the procedures and requirements in you approved site specific test plan as required in § 63.7(e). The reportable measurement output from the HAP metals CEMS must be expressed in units of the applicable emissions limit (*e.g.*, lb/MMBtu, lb/MWh) and in the form of a 30-boiler operating day rolling average.

(ii) Operate and maintain your HAP metals CEMS according to the procedures and criteria in your site specific performance evaluation and quality control program plan required in § 63.8(d).

(2) Collect HAP metals CEMS hourly average output data for all boiler operating hours except as indicated in section (j)(4) of this section.

(3) Calculate the arithmetic 30-boiler operating day rolling average of all of the hourly average HAP metals CEMS output data collected during all nonexempt boiler operating hours data.

(4) You must collect data using the HAP metals CEMS at all times the process unit is operating and at the intervals specified in paragraph (a) of this section, except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, and required monitoring system quality assurance or quality control activities.

(i) You must use all the data collected during all boiler operating hours in assessing the compliance with your emission limit except:

(A) Any data collected during monitoring system malfunctions, repairs associated with monitoring system malfunctions, or required monitoring

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system quality assurance or control activities conducted during monitoring system malfunctions in calculations and report any such periods in your annual deviation report;

(B) Any data collected during periods when the monitoring system is out of control as specified in your site-specific monitoring plan, repairs associated with periods when the monitoring system is out of control, or required monitoring system quality assurance or control activities conducted during out of control periods in calculations used to report emissions or operating levels and report any such periods in your annual deviation report;

(C) Any data recorded during periods of startup or shutdown.

(ii) You must record and make available upon request results of HAP metals CEMS system performance audits, dates and duration of periods when the HAP metals CEMS is out of control to completion of the corrective actions necessary to return the HAP metals CEMS to operation consistent with your site-specific performance evaluation and quality control program plan.

(k) If you demonstrate compliance with the HCl and HF emission limits for a liquid oil-fired EGU by conducting quarterly testing, you must also develop a site-specific monitoring plan as provided for in § 63.10000(c)(2)(iii) and Table 7 to this subpart.

§ 63.10011 How do I demonstrate initial compliance with the emissions limits and work practice standards?

(a) You must demonstrate initial compliance with each emissions limit that applies to you by conducting performance testing.

(b) If you are subject to an operating limit in Table 4 to this subpart, you demonstrate initial compliance with HAP metals or filterable PM emission limit(s) through performance stack tests and you elect to use a PM CPMS to demonstrate continuous performance, or if, for a liquid oil-fired unit, and you use quarterly stack testing for HCl and HF plus site-specific parameter monitoring to demonstrate continuous performance, you must also establish a site-specific operating limit, in accordance with Table 4 to this subpart, § 63.10007, and Table 6 to this subpart. You may use only the parametric data recorded during successful performance tests (*i.e.*, tests that demonstrate compliance with the applicable emissions limits) to establish an operating limit.

(c)(1) If you use CEMS or sorbent trap monitoring systems to measure a HAP (*e.g.*, Hg or HCl) directly, the first 30-boiler operating day rolling average emission rate obtained with certified CEMS after the applicable date in § 63.9984 (or, if applicable, prior to that date, as described in § 63.10005(b)(2)), expressed in units of the standard, is the initial performance test. Initial compliance is demonstrated if the results of the performance test meet the applicable emission limit in Table 1 or 2 to this subpart.

(2) For a unit that uses a CEMS to measure SO_2 or PM emissions for initial compliance, the first 30 boiler operating day average emission rate obtained with certified CEMS after the applicable date in § 63.9984 (or, if applicable, prior to that date, as described in § 63.10005(b)(2)), expressed in units of the standard, is the initial performance test. Initial compliance is demonstrated if the results of the performance test meet the applicable SO_2 or filterable PM emission limit in Table 1 or 2 to this subpart.

(d) For candidate LEE units, use the results of the performance testing described in § 63.10005(h) to determine initial compliance with the applicable emission limit(s) in Table 1 or 2 to this subpart and to determine whether the unit qualifies for LEE status.

(e) You must submit a Notification of Compliance Status containing the results of the initial compliance demonstration, according to § 63.10030(e).

(f)(1) You must determine the fuel whose combustion produces the least uncontrolled emissions, *i.e.*, the cleanest fuel, either natural gas or distillate oil, that is available on site or accessible nearby for use during periods of startup or shutdown.

(2) Your cleanest fuel, either natural gas or distillate oil, for use during periods of startup or shutdown determination may take safety considerations into account.

(g) You must follow the startup or shutdown requirements given in Table 3 for each coal-fired, liquid oil-fired, and solid oil-derived fuel-fired EGU.

Continuous Compliance Requirements

§ 63.10020 How do I monitor and collect data to demonstrate continuous compliance?

(a) You must monitor and collect data according to this section and the site-specific monitoring plan required by § 63.10000(d).

(b) You must operate the monitoring system and collect data at all required intervals at all times that the affected EGU is operating, except for periods of monitoring system malfunctions or out-of-control periods (see § 63.8(c)(7) of this part), and required monitoring system quality assurance or quality control activities, including, as applicable, calibration checks and required zero and span adjustments. You are required to affect monitoring system repairs in response to monitoring system malfunctions and to return the monitoring system to operation as expeditiously as practicable.

(c) You may not use data recorded during EGU startup or shutdown or monitoring system malfunctions or monitoring system out-of-control periods, repairs associated with monitoring system malfunctions or monitoring system out-of-control periods, or required monitoring system quality assurance or control activities in calculations used to report emissions or operating levels. You must use all the data collected during all other periods in assessing the operation of the control device and associated control system.

(d) Except for periods of monitoring system malfunctions or monitoring system out-of-control periods, repairs associated with monitoring system malfunctions or monitoring system out-of-control periods, and required monitoring system quality assurance or quality control activities including, as applicable, calibration checks and required zero and span adjustments), failure to collect required data is a deviation of the monitoring requirements.

§ 63.10021 How do I demonstrate continuous compliance with the emission limitations, operating limits, and work practice standards?

(a) You must demonstrate continuous compliance with each emissions limit, operating limit, and work practice standard in Tables 1 through 4 to this subpart that applies to you, according to the monitoring specified in Tables 6 and 7 to this subpart and paragraphs (b) through (g) of this section.

(b) Except as otherwise provided in § 63.10020(c), if you use a CEMS to measure SO_2, PM, HCl, HF, or Hg emissions, or using a sorbent trap monitoring system to measure Hg emissions, you must demonstrate continuous compliance by using all quality-assured hourly data recorded by the CEMS (or sorbent trap monitoring system) and the other required monitoring systems (*e.g.*, flow rate, CO_2, O_2, or moisture systems) to calculate the arithmetic average emissions rate in units of the standard on a continuous 30-boiler operating day rolling average basis, updated at the end of each new boiler operating day. Use Equation 8 to determine the 30-boiler operating day rolling average.

$$30\ boiler\ operating\ day\ average = \frac{\sum_{i=1}^{n} Her_i}{n}\ (Eq.\ 8)$$

Where:

Her_i is the hourly emissions rate for hour i and n is the number of hourly emissions rate values collected over 30 boiler operating days.

(c) If you use a PM CPMS data to measure compliance with an operating limit in Table 4 to this subpart, you must record the PM CPMS output data for all periods when the process is operating and the PM CPMS is not out-of-control. You must demonstrate continuous compliance by using all quality-assured hourly average data collected by the PM CPMS for all operating hours to calculate the arithmetic average operating parameter in units of the operating limit (*e.g.*, milliamps, PM concentration, raw data signal) on a 30 operating day rolling average basis, updated at the end of each new boiler operating day. Use Equation 9 to determine the 30 boiler operating day average.

$$30\ boiler\ operating\ day\ average = \frac{\sum_{i=1}^{n} Hpv_i}{n}\ (Eq.\ 9)$$

Where:

Hpv_i is the hourly parameter value for hour i and n is the number of valid hourly parameter values collected over 30 boiler operating days.

(d) If you use quarterly performance testing to demonstrate compliance with one or more applicable emissions limits in Table 1 or 2 to this subpart, you

(1) May skip performance testing in those quarters during which less than 168 boiler operating hours occur, except that a performance test must be conducted at least once every calendar year.

(2) Must conduct the performance test as defined in Table 5 to this subpart and calculate the results of the testing in units of the applicable emissions standard; and

(3) Must conduct site-specific monitoring for a liquid oil-fired unit to ensure compliance with the HCl and HF emission limits in Tables 1 and 2 to this subpart, in accordance with the requirements of § 63.10000(c)(2)(iii). The monitoring must meet the general operating requirements provided in § 63.10020(a).

(e) If you must conduct periodic performance tune-ups of your EGU(s), as specified in paragraphs (e)(1) through (9) of this section, perform the first tune-up as part of your initial compliance demonstration. Notwithstanding this requirement, you may delay the first burner inspection until the next scheduled unit outage provided you meet the requirements of § 63.10005. Subsequently, you must perform an inspection of the burner at least once every 36 calendar months unless your EGU employs neural network combustion optimization during normal operations in which case you must perform an inspection of the burner and combustion controls at least once every 48 calendar months.

(1) As applicable, inspect the burner and combustion controls, and clean or replace any components of the burner or combustion controls as necessary upon initiation of the work practice program and at least once every required inspection period. Repair of a burner or combustion control component requiring special order parts may be scheduled as follows:

(i) Burner or combustion control component parts needing replacement that affect the ability to optimize NO_X and CO must be installed within 3 calendar months after the burner inspection,

(ii) Burner or combustion control component parts that do not affect the ability to optimize NO_X and CO may be installed on a schedule determined by the operator;

(2) As applicable, inspect the flame pattern and make any adjustments to the burner or combustion controls necessary to optimize the flame pattern. The adjustment should be consistent with the manufacturer's specifications, if available, or in accordance with best combustion engineering practice for that burner type;

(3) As applicable, observe the damper operations as a function of mill and/or cyclone loadings, cyclone and pulverizer coal feeder loadings, or other pulverizer and coal mill performance parameters, making adjustments and effecting repair to dampers, controls, mills, pulverizers, cyclones, and sensors;

(4) As applicable, evaluate windbox pressures and air proportions, making adjustments and effecting repair to dampers, actuators, controls, and sensors;

(5) Inspect the system controlling the air-to-fuel ratio and ensure that it is correctly calibrated and functioning properly. Such inspection may include calibrating excess O_2 probes and/or sensors, adjusting overfire air systems, changing software parameters, and calibrating associated actuators and dampers to ensure that the systems are operated as designed. Any component out of calibration, in or near failure, or in a state that is likely to negate combustion optimization efforts prior to the next tune-up, should be corrected or repaired as necessary;

(6) Optimize combustion to minimize generation of CO and NO_X. This optimization should be consistent with the manufacturer's specifications, if available, or best combustion engineering practice for the applicable burner type. NO_X optimization includes burners, overfire air controls, concentric firing system improvements, neural network or combustion efficiency software, control systems calibrations, adjusting combustion zone temperature profiles, and add-on controls such as SCR and SNCR; CO optimization includes burners, overfire air controls, concentric firing system improvements, neural network or combustion efficiency software, control systems calibrations, and adjusting combustion zone temperature profiles;

(7) While operating at full load or the predominantly operated load, measure the concentration in the effluent stream of CO and NO_X in ppm, by volume, and oxygen in volume percent, before and after the tune-up adjustments are made (measurements may be either on a dry or wet basis, as long as it is the same basis before and after the adjustments are made). You may use portable CO, NO_X and O_2 monitors for this measurement. EGU's employing neural network optimization systems need only provide a single pre- and post-tune-up value rather than continual values before and after each optimization adjustment made by the system;

(8) Maintain on-site and submit, if requested by the Administrator, an annual report containing the information in paragraphs (e)(1) through (e)(9) of this section including:

(i) The concentrations of CO and NO_x in the effluent stream in ppm by volume, and oxygen in volume percent, measured before and after an adjustment of the EGU combustion systems;

(ii) A description of any corrective actions taken as a part of the combustion adjustment; and

(iii) The type(s) and amount(s) of fuel used over the 12 calendar months prior to an adjustment, but only if the unit was physically and legally capable of using more than one type of fuel during that period; and

(9) Report the dates of the initial and subsequent tune-ups as follows:

(i) If the first required tune-up is performed as part of the initial compliance demonstration, report the date of the tune-up in hard copy (as specified in § 63.10030) and electronically (as specified in § 63.10031). Report the date of each subsequent tune-up electronically (as specified in § 63.10031).

(ii) If the first tune-up is not conducted as part of the initial compliance demonstration, but is postponed until the next unit outage, report the date of that tune-up and all subsequent tune-ups electronically, in accordance with § 63.10031.

(f) You must submit the reports required under § 63.10031 and, if applicable, the reports required under appendices A and B to this subpart. The electronic reports required by appendices A and B to this subpart must be sent to the Administrator electronically in a format prescribed by the Administrator, as provided in § 63.10031. CEMS data (except for PM CEMS and any approved alternative monitoring using a HAP metals CEMS) shall be submitted using EPA's Emissions Collection and Monitoring Plan System (ECMPS) Client Tool. Other data, including PM CEMS data, HAP metals CEMS data, and CEMS performance test detail reports, shall be submitted in the file format generated through use of EPA's Electronic Reporting Tool, the Compliance and Emissions Data Reporting Interface, or alternate electronic file format, all as provided for under § 63.10031.

(g) You must report each instance in which you did not meet an applicable emissions limit or operating limit in Tables 1 through 4 to this subpart or failed to conduct a required tune-up. These instances are deviations from the requirements of this subpart. These deviations must be reported according to § 63.10031.

(h) You must keep records as specified in § 63.10032 during periods of startup and shutdown.

(i) You must provide reports as specified in § 63.10031 concerning activities and periods of startup and shutdown.

§ 63.10022 How do I demonstrate continuous compliance under the emissions averaging provision?

(a) Following the compliance date, the owner or operator must demonstrate compliance with this subpart on a continuous basis by meeting the requirements of paragraphs (a)(1) through (3) of this section.

(1) For each calendar month, demonstrate compliance with the average weighted emissions limit for the existing units participating in the emissions averaging option as determined in § 63.10009(f) and (g);

(2) For each existing unit participating in the emissions averaging option that is equipped with PM CPMS, maintain the average parameter value at or below the operating limit established during the most recent performance test;

(3) For each existing unit participating in the emissions averaging option venting to a common stack configuration containing affected units from other subcategories, maintain the appropriate operating limit for each unit as specified in Table 4 to this subpart that applies.

(b) Any instance where the owner or operator fails to comply with the continuous monitoring requirements in paragraphs (a)(1) through (3) of this section is a deviation.

§ 63.10023 How do I establish my PM CPMS operating limit and determine compliance with it?

(a) During the initial performance test or any such subsequent performance test that demonstrates compliance with the filterable PM, individual non-mercury HAP metals, or total non-mercury HAP metals limit (or for liquid oil-fired units, individual HAP metals or total HAP metals limit, including Hg) in Table 1 or 2, record all hourly average output values (*e.g.*, milliamps, stack concentration, or other raw data signal) from the PM CPMS for the periods corresponding to the test runs (*e.g.*, nine 1-hour average PM CPMS output values for three 3-hour test runs).

(b) Determine your operating limit as the highest 1-hour average PM CPMS output value recorded during the performance test. You must verify an existing or establish a new operating limit after each repeated performance test.

(c) You must operate and maintain your process and control equipment such that the 30 operating day average PM CPMS output does not exceed the operating limit determined in paragraphs (a) and (b) of this section.

Notification, Reports, and Records

§ 63.10030 What notifications must I submit and when?

(a) You must submit all of the notifications in §§ 63.7(b) and (c), 63.8 (e), (f)(4) and (6), and 63.9 (b) through (h) that apply to you by the dates specified.

(b) As specified in § 63.9(b)(2), if you startup your affected source before April 16, 2012, you must submit an Initial Notification not later than 120 days after April 16, 2012.

(c) As specified in § 63.9(b)(4) and (b)(5), if you startup your new or reconstructed affected source on or after April 16, 2012, you must submit an Initial Notification not later than 15 days after the actual date of startup of the affected source.

(d) When you are required to conduct a performance test, you must submit a Notification of Intent to conduct a performance test at least 30 days before the performance test is scheduled to begin.

(e) When you are required to conduct an initial compliance demonstration as specified in § 63.10011(a), you must submit a Notification of Compliance Status according to § 63.9(h)(2)(ii). The Notification of Compliance Status report must contain all the information specified in paragraphs (e)(1) through (7), as applicable.

(1) A description of the affected source(s) including identification of which subcategory the source is in, the design capacity of the source, a description of the add-on controls used on the source, description of the fuel(s) burned, including whether the fuel(s) were determined by you or EPA through a petition process to be a non-waste under 40 CFR 241.3, whether the fuel(s) were processed from discarded non-hazardous secondary materials within the meaning of 40 CFR 241.3, and justification for the selection of fuel(s) burned during the performance test.

(2) Summary of the results of all performance tests and fuel analyses and calculations conducted to demonstrate initial compliance including all established operating limits.

(3) Identification of whether you plan to demonstrate compliance with each applicable emission limit through performance testing; fuel moisture analyses; performance testing with operating limits (*e.g.*, use of PM CPMS); CEMS; or a sorbent trap monitoring system.

(4) Identification of whether you plan to demonstrate compliance by emissions averaging.

(5) A signed certification that you have met all applicable emission limits and work practice standards.

(6) If you had a deviation from any emission limit, work practice standard, or operating limit, you must also submit a brief description of the deviation, the duration of the deviation, emissions point identification, and the cause of the deviation in the Notification of Compliance Status report.

(7) In addition to the information required in § 63.9(h)(2), your notification of compliance status must include the following:

(i) A summary of the results of the annual performance tests and documentation of any operating limits that were reestablished during this test, if applicable. If you are conducting stack tests once every 3 years consistent with § 63.10006(i), the date of the last three stack tests, a comparison of the emission level you achieved in the last three stack tests to the 50 percent emission limit threshold required in § 63.10006(i), and a statement as to whether there have been any operational changes since the last stack test that could increase emissions.

(ii) Certifications of compliance, as applicable, and must be signed by a responsible official stating:

(A) "This EGU complies with the requirements in § 63.10021(a) to demonstrate continuous compliance." and

(B) "No secondary materials that are solid waste were combusted in any affected unit."

§ 63.10031 What reports must I submit and when?

(a) You must submit each report in Table 8 to this subpart that applies to you. If you are required to (or elect to) continuously monitor Hg and/or HCl and/or HF emissions, you must also submit the electronic reports required under appendix A and/or appendix B to the subpart, at the specified frequency.

(b) Unless the Administrator has approved a different schedule for submission of reports under § 63.10(a), you must submit each report by the date in Table 8 to this subpart and according to the requirements in paragraphs (b)(1) through (5) of this section.

(1) The first compliance report must cover the period beginning on the compliance date that is specified for your affected source in § 63.9984 and ending on June 30 or December 31, whichever date is the first date that occurs at least 180 days after the compliance date that is specified for your source in § 63.9984.

(2) The first compliance report must be postmarked or submitted electronically no later than July 31 or January 31, whichever date is the first date following the end of the first calendar half after the compliance date that is specified for your source in § 63.9984.

(3) Each subsequent compliance report must cover the semiannual reporting period from January 1 through June 30 or the semiannual reporting period from July 1 through December 31.

(4) Each subsequent compliance report must be postmarked or submitted electronically no later than July 31 or January 31, whichever date is the first date following the end of the semiannual reporting period.

(5) For each affected source that is subject to permitting regulations pursuant to part 70 or part 71 of this chapter, and if the permitting authority has established dates for submitting semiannual reports pursuant to 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A), you may submit the first and subsequent compliance reports according to the dates the permitting authority has established instead of according to the dates in paragraphs (b)(1) through (4) of this section.

(c) The compliance report must contain the information required in paragraphs (c)(1) through (4) of this section.

(1) The information required by the summary report located in 63.10(e)(3)(vi).

(2) The total fuel use by each affected source subject to an emission limit, for each calendar month within the semiannual reporting period, including, but not limited to, a description of the fuel, whether the fuel has received a non-waste determination by EPA or your basis for concluding that the fuel is not a waste, and the total fuel usage amount with units of measure.

(3) Indicate whether you burned new types of fuel during the reporting period. If you did burn new types of fuel you must include the date of the performance test where that fuel was in use.

(4) Include the date of the most recent tune-up for each unit subject to the requirement to conduct a performance tune-up according to § 63.10021(e). Include the date of the most recent burner inspection if it was not done annually and was delayed until the next scheduled unit shutdown.

(d) For each excess emissions occurring at an affected source where you are using a CMS to comply with that emission limit or operating limit, you must include the information required in § 63.10(e)(3)(v) in the compliance report specified in section (c).

(e) Each affected source that has obtained a Title V operating permit pursuant to part 70 or part 71 of this chapter must report all deviations as defined in this subpart in the semiannual monitoring report required by 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A). If an affected source submits a compliance report pursuant to Table 8 to this subpart along with, or as part of, the semiannual monitoring report required by 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A), and the compliance report includes all required information concerning deviations from any emission limit, operating limit, or work practice requirement in this subpart, submission of the compliance report satisfies any obligation to report the same deviations in the semiannual monitoring report. Submission of a compliance report does not otherwise affect any obligation the affected source may have to report deviations from permit requirements to the permit authority.

(f) As of January 1, 2012, and within 60 days after the date of completing each performance test, you must submit the results of the performance tests required by this subpart to EPA's WebFIRE database by using the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX) (*www.epa.gov/cdx*). Performance test data must be submitted in the file format generated through use of EPA's Electronic Reporting Tool (ERT) (see *http://www.epa.gov/ttn/chief/ert/index.html*). Only data collected using those test methods on the ERT Web site are subject to this requirement for submitting reports electronically to WebFIRE. Owners or operators who claim that some of the information being submitted for performance tests is confidential business information (CBI) must submit a complete ERT file including information claimed to be CBI on a compact disk or other commonly used electronic storage media (including, but not limited to, flash drives) to EPA. The electronic media must be clearly marked as CBI and mailed to U.S. EPA/OAPQS/CORE CBI Office, Attention: WebFIRE Administrator, MD C404–02, 4930 Old Page Rd., Durham, NC 27703. The same ERT file with the CBI omitted must be submitted to EPA via CDX as described earlier in this paragraph. At the discretion of the delegated authority, you must also submit these reports, including the confidential business information, to the delegated authority

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in the format specified by the delegated authority.

(1) Within 60 days after the date of completing each CEMS (SO_2, PM, HCl, HF, and Hg) performance evaluation test, as defined in § 63.2 and required by this subpart, you must submit the relative accuracy test audit (RATA) data (or, for PM CEMS, RCA and RRA data) required by this subpart to EPA's WebFIRE database by using the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX) (*www.epa.gov/cdx*). The RATA data shall be submitted in the file format generated through use of EPA's Electronic Reporting Tool (ERT) (*http://www.epa.gov/ttn/chief/ert/index.html*). Only RATA data compounds listed on the ERT Web site are subject to this requirement. Owners or operators who claim that some of the information being submitted for RATAs is confidential business information (CBI) shall submit a complete ERT file including information claimed to be CBI on a compact disk or other commonly used electronic storage media (including, but not limited to, flash drives) by registered letter to EPA and the same ERT file with the CBI omitted to EPA via CDX as described earlier in this paragraph. The compact disk or other commonly used electronic storage media shall be clearly marked as CBI and mailed to U.S. EPA/OAPQS/CORE CBI Office, Attention: WebFIRE Administrator, MD C404–02, 4930 Old Page Rd., Durham, NC 27703. At the discretion of the delegated authority, owners or operators shall also submit these RATAs to the delegated authority in the format specified by the delegated authority. Owners or operators shall submit calibration error testing, drift checks, and other information required in the performance evaluation as described in § 63.2 and as required in this chapter.

(2) For a PM CEMS, PM CPMS, or approved alternative monitoring using a HAP metals CEMS, within 60 days after the reporting periods ending on March 31st, June 30th, September 30th, and December 31st, you must submit quarterly reports to EPA's WebFIRE database by using the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX) (*www.epa.gov/cdx*). You must use the appropriate electronic reporting form in CEDRI or provide an alternate electronic file consistent with EPA's reporting form output format. For each reporting period, the quarterly reports must include all of the calculated 30-boiler operating day rolling average values derived from the CEMS and PM CPMS.

(3) Reports for an SO_2 CEMS, a Hg CEMS or sorbent trap monitoring system, an HCl or HF CEMS, and any supporting monitors for such systems (such as a diluent or moisture monitor) shall be submitted using the ECMPS Client Tool, as provided for in Appendices A and B to this subpart and § 63.10021(f).

(4) Submit the compliance reports required under paragraphs (c) and (d) of this section and the notification of compliance status required under § 63.10030(e) to EPA's WebFIRE database by using the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX) (*www.epa.gov/cdx*). You must use the appropriate electronic reporting form in CEDRI or provide an alternate electronic file consistent with EPA's reporting form output format.

(5) All reports required by this subpart not subject to the requirements in paragraphs (f)(1) through (4) of this section must be sent to the Administrator at the appropriate address listed in § 63.13. If acceptable to both the Administrator and the owner or operator of a source, these reports may be submitted on electronic media. The Administrator retains the right to require submittal of reports subject to paragraphs (f)(1), (2), and (3) of this section in paper format.

(g) If you had a malfunction during the reporting period, the compliance report must include the number, duration, and a brief description for each type of malfunction which occurred during the reporting period and which caused or may have caused any applicable emission limitation to be exceeded.

§ 63.10032 What records must I keep?

(a) You must keep records according to paragraphs (a)(1) and (2) of this section. If you are required to (or elect to) continuously monitor Hg and/or HCl and/or HF emissions, you must also keep the records required under appendix A and/or appendix B to this subpart.

(1) A copy of each notification and report that you submitted to comply with this subpart, including all documentation supporting any Initial Notification or Notification of Compliance Status or semiannual compliance report that you submitted, according to the requirements in § 63.10(b)(2)(xiv).

(2) Records of performance stack tests, fuel analyses, or other compliance demonstrations and performance evaluations, as required in § 63.10(b)(2)(viii).

(b) For each CEMS and CPMS, you must keep records according to paragraphs (b)(1) through (4) of this section.

(1) Records described in § 63.10(b)(2)(vi) through (xi).

(2) Previous (*i.e.*, superseded) versions of the performance evaluation plan as required in § 63.8(d)(3).

(3) Request for alternatives to relative accuracy test for CEMS as required in § 63.8(f)(6)(i).

(4) Records of the date and time that each deviation started and stopped, and whether the deviation occurred during a period of startup, shutdown, or malfunction or during another period.

(c) You must keep the records required in Table 7 to this subpart including records of all monitoring data and calculated averages for applicable PM CPMS operating limits to show continuous compliance with each emission limit and operating limit that applies to you.

(d) For each EGU subject to an emission limit, you must also keep the records in paragraphs (d)(1) through (3) of this section.

(1) You must keep records of monthly fuel use by each EGU, including the type(s) of fuel and amount(s) used.

(2) If you combust non-hazardous secondary materials that have been determined not to be solid waste pursuant to 40 CFR 241.3(b)(1), you must keep a record which documents how the secondary material meets each of the legitimacy criteria. If you combust a fuel that has been processed from a discarded non-hazardous secondary material pursuant to 40 CFR 241.3(b)(2), you must keep records as to how the operations that produced the fuel satisfies the definition of processing in 40 CFR 241.2. If the fuel received a non-waste determination pursuant to the petition process submitted under 40 CFR 241.3(c), you must keep a record which documents how the fuel satisfies the requirements of the petition process.

(3) For an EGU that qualifies as an LEE under § 63.10005(h), you must keep annual records that document that your emissions in the previous stack test(s) continue to qualify the unit for LEE status for an applicable pollutant, and document that there was no change in source operations including fuel composition and operation of air pollution control equipment that would cause emissions of the pollutant to increase within the past year.

(e) If you elect to average emissions consistent with § 63.10009, you must additionally keep a copy of the emissions averaging implementation

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plan required in § 63.10009(g), all calculations required under § 63.10009, including daily records of heat input or steam generation, as applicable, and monitoring records consistent with § 63.10022.

(f) You must keep records of the occurrence and duration of each startup and/or shutdown.

(g) You must keep records of the occurrence and duration of each malfunction of an operation (*i.e.*, process equipment) or the air pollution control and monitoring equipment.

(h) You must keep records of actions taken during periods of malfunction to minimize emissions in accordance with § 63.10000(b), including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation.

(i) You must keep records of the type(s) and amount(s) of fuel used during each startup or shutdown.

(j) If you elect to establish that an EGU qualifies as a limited-use liquid oil-fired EGU, you must keep records of the type(s) and amount(s) of fuel use in each calendar quarter to document that the capacity factor limitation for that subcategory is met.

§ 63.10033 In what form and how long must I keep my records?

(a) Your records must be in a form suitable and readily available for expeditious review, according to § 63.10(b)(1).

(b) As specified in § 63.10(b)(1), you must keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record.

(c) You must keep each record on site for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to § 63.10(b)(1). You can keep the records off site for the remaining 3 years.

Other Requirements and Information

§ 63.10040 What parts of the General Provisions apply to me?

Table 9 to this subpart shows which parts of the General Provisions in §§ 63.1 through 63.15 apply to you.

§ 63.10041 Who implements and enforces this subpart?

(a) This subpart can be implemented and enforced by U.S. EPA, or a delegated authority such as your state, local, or tribal agency. If the EPA Administrator has delegated authority to your state, local, or tribal agency, then that agency (as well as the U.S. EPA) has the authority to implement and enforce this subpart. You should contact your EPA Regional Office to find out if this subpart is delegated to your state, local, or tribal agency.

(b) In delegating implementation and enforcement authority of this subpart to a state, local, or tribal agency under 40 CFR part 63, subpart E, the authorities listed in paragraphs (b)(1) through (4) of this section are retained by the EPA Administrator and are not transferred to the state, local, or tribal agency; moreover, the U.S. EPA retains oversight of this subpart and can take enforcement actions, as appropriate, with respect to any failure by any person to comply with any provision of this subpart.

(1) Approval of alternatives to the non-opacity emission limits and work practice standards in § 63.9991(a) and (b) under § 63.6(g).

(2) Approval of major change to test methods in Table 5 to this subpart under § 63.7(e)(2)(ii) and (f) and as defined in § 63.90, approval of minor and intermediate changes to monitoring performance specifications/procedures in Table 5 where the monitoring serves as the performance test method (see definition of "test method" in § 63.2.

(3) Approval of major changes to monitoring under § 63.8(f) and as defined in § 63.90.

(4) Approval of major change to recordkeeping and reporting under § 63.10(e) and as defined in § 63.90.

§ 63.10042 What definitions apply to this subpart?

Terms used in this subpart are defined in the Clean Air Act (CAA), in § 63.2 (the General Provisions), and in this section as follows:

Affirmative defense means, in the context of an enforcement proceeding, a response or defense put forward by a defendant, regarding which the defendant has the burden of proof, and the merits of which are independently and objectively evaluated in a judicial or administrative proceeding.

Anthracite coal means solid fossil fuel classified as anthracite coal by American Society of Testing and Materials (ASTM) Method D388–05, "Standard Classification of Coals by Rank" (incorporated by reference, see § 63.14).

Bituminous coal means coal that is classified as bituminous according to ASTM Method D388–05, "Standard Classification of Coals by Rank" (incorporated by reference, see § 63.14).

Boiler operating day means a 24-hour period between midnight and the following midnight during which any fuel is combusted at any time in the steam generating unit. It is not necessary for the fuel to be combusted the entire 24-hour period.

Capacity factor for a liquid oil-fired EGU means the total annual heat input from oil divided by the product of maximum hourly heat input for the EGU, regardless of fuel, multiplied by 8,760 hours.

Coal means all solid fuels classifiable as anthracite, bituminous, subbituminous, or lignite by ASTM Method D388–05, "Standard Classification of Coals by Rank" (incorporated by reference, see § 63.14), and coal refuse. Synthetic fuels derived from coal for the purpose of creating useful heat including but not limited to, coal derived gases (not meeting the definition of natural gas), solvent-refined coal, coal-oil mixtures, and coal-water mixtures, are considered "coal" for the purposes of this subpart.

Coal-fired electric utility steam generating unit means an electric utility steam generating unit meeting the definition of "fossil fuel-fired" that burns coal for more than 10.0 percent of the average annual heat input during any 3 consecutive calendar years or for more than 15.0 percent of the annual heat input during any one calendar year.

Coal refuse means any by-product of coal mining, physical coal cleaning, and coal preparation operations (*e.g.*, culm, gob, etc.) containing coal, matrix material, clay, and other organic and inorganic material with an ash content greater than 50 percent (by weight) and a heating value less than 13,900 kilojoules per kilogram (6,000 Btu per pound) on a dry basis.

Cogeneration means a steam-generating unit that simultaneously produces both electrical and useful thermal (or mechanical) energy from the same primary energy source.

Cogeneration unit means a stationary, fossil fuel-fired EGU meeting the definition of "fossil fuel-fired" or stationary, integrated gasification combined cycle:

(1) Having equipment used to produce electricity and useful thermal energy for industrial, commercial, heating, or cooling purposes through the sequential use of energy; and

(2) Producing during the 12-month period starting on the date the unit first produces electricity and during any calendar year after which the unit first produces electricity:

(i) For a topping-cycle cogeneration unit,

(A) Useful thermal energy not less than 5 percent of total energy output; and

(B) Useful power that, when added to one-half of useful thermal energy produced, is not less than 42.5 percent

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of total energy input, if useful thermal energy produced is 15 percent or more of total energy output, or not less than 45 percent of total energy input, if useful thermal energy produced is less than 15 percent of total energy output.

(ii) For a bottoming-cycle cogeneration unit, useful power not less than 45 percent of total energy input.

(3) Provided that the total energy input under paragraphs (2)(i)(B) and (2)(ii) of this definition shall equal the unit's total energy input from all fuel except biomass if the unit is a boiler.

Combined-cycle gas stationary combustion turbine means a stationary combustion turbine system where heat from the turbine exhaust gases is recovered by a waste heat boiler.

Common stack means the exhaust of emissions from two or more affected units through a single flue.

Continental liquid oil-fired subcategory means any oil-fired electric utility steam generating unit that burns liquid oil and is located in the continental United States.

Deviation. (1) *Deviation* means any instance in which an affected source subject to this subpart, or an owner or operator of such a source:

(i) Fails to meet any requirement or obligation established by this subpart including, but not limited to, any emission limit, operating limit, work practice standard, or monitoring requirement; or

(ii) Fails to meet any term or condition that is adopted to implement an applicable requirement in this subpart and that is included in the operating permit for any affected source required to obtain such a permit.

(2) A deviation is not always a violation. The determination of whether a deviation constitutes a violation of the standard is up to the discretion of the entity responsible for enforcement of the standards.

Distillate oil means fuel oils, including recycled oils, that comply with the specifications for fuel oil numbers 1 and 2, as defined by ASTM Method D396–10, "Standard Specification for Fuel Oils" (incorporated by reference, see § 63.14).

Dry flue gas desulfurization technology, or *dry FGD,* or *spray dryer absorber* (*SDA*), or *spray dryer,* or *dry scrubber* means an add-on air pollution control system located downstream of the steam generating unit that injects a dry alkaline sorbent (dry sorbent injection) or sprays an alkaline sorbent slurry (spray dryer) to react with and neutralize acid gases such as SO_2 and HCl in the exhaust stream forming a dry powder material. Alkaline sorbent injection systems in fluidized bed combustors (FBC) or circulating fluidized bed (CFB) boilers are included in this definition.

Dry sorbent injection (DSI) means an add-on air pollution control system in which sorbent (*e.g.*, conventional activated carbon, brominated activated carbon, Trona, hydrated lime, sodium carbonate, etc.) is injected into the flue gas steam upstream of a PM control device to react with and neutralize acid gases (such as SO_2 and HCl) or Hg in the exhaust stream forming a dry powder material that may be removed in a primary or secondary PM control device.

Electric Steam generating unit means any furnace, boiler, or other device used for combusting fuel for the purpose of producing steam (including fossil-fuel-fired steam generators associated with integrated gasification combined cycle gas turbines; nuclear steam generators are not included) for the purpose of powering a generator to produce electricity or electricity and other thermal energy.

Electric utility steam generating unit (EGU) means a fossil fuel-fired combustion unit of more than 25 megawatts electric (MWe) that serves a generator that produces electricity for sale. A fossil fuel-fired unit that cogenerates steam and electricity and supplies more than one-third of its potential electric output capacity and more than 25 MWe output to any utility power distribution system for sale is considered an electric utility steam generating unit.

Emission limitation means any emissions limit, work practice standard, or operating limit.

Excess emissions means, with respect to this subpart, results of any required measurements outside the applicable range (*e.g.*, emissions limitations, parametric operating limits) that is permitted by this subpart. The values of measurements will be in the same units and averaging time as the values specified in this subpart for the limitations.

Federally enforceable means all limitations and conditions that are enforceable by the Administrator, including the requirements of 40 CFR parts 60, 61, and 63; requirements within any applicable state implementation plan; and any permit requirements established under 40 CFR 52.21 or under 40 CFR 51.18 and 40 CFR 51.24.

Flue gas desulfurization system means any add-on air pollution control system located downstream of the steam generating unit whose purpose or effect is to remove at least 50 percent of the SO_2 in the exhaust gas stream.

Fossil fuel means natural gas, oil, coal, and any form of solid, liquid, or gaseous fuel derived from such material.

Fossil fuel-fired means an electric utility steam generating unit (EGU) that is capable of combusting more than 25 MW of fossil fuels. To be "capable of combusting" fossil fuels, an EGU would need to have these fuels allowed in its operating permit and have the appropriate fuel handling facilities on-site or otherwise available (*e.g.*, coal handling equipment, including coal storage area, belts and conveyers, pulverizers, etc.; oil storage facilities). In addition, fossil fuel-fired means any EGU that fired fossil fuels for more than 10.0 percent of the average annual heat input during any 3 consecutive calendar years or for more than 15.0 percent of the annual heat input during any one calendar year after the applicable compliance date.

Fuel type means each category of fuels that share a common name or classification. Examples include, but are not limited to, bituminous coal, subbituminous coal, lignite, anthracite, biomass, and residual oil. Individual fuel types received from different suppliers are not considered new fuel types.

Fluidized bed boiler, or *fluidized bed combustor,* or *circulating fluidized boiler,* or *CFB* means a boiler utilizing a fluidized bed combustion process.

Fluidized bed combustion means a process where a fuel is burned in a bed of granulated particles which are maintained in a mobile suspension by the upward flow of air and combustion products.

Gaseous fuel includes, but is not limited to, natural gas, process gas, landfill gas, coal derived gas, solid oil-derived gas, refinery gas, and biogas.

Generator means a device that produces electricity.

Gross output means the gross useful work performed by the steam generated and, for an IGCC electric utility steam generating unit, the work performed by the stationary combustion turbines. For a unit generating only electricity, the gross useful work performed is the gross electrical output from the unit's turbine/generator sets. For a cogeneration unit, the gross useful work performed is the gross electrical output, including any such electricity used in the power production process (which process includes, but is not limited to, any on-site processing or treatment of fuel combusted at the unit and any on-site emission controls), or mechanical output plus 75 percent of the useful thermal output measured relative to ISO conditions that is not used to generate additional electrical or mechanical

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output or to enhance the performance of the unit (*i.e.,* steam delivered to an industrial process).

Heat input means heat derived from combustion of fuel in an EGU (synthetic gas for an IGCC) and does not include the heat input from preheated combustion air, recirculated flue gases, or exhaust gases from other sources such as gas turbines, internal combustion engines, etc.

Integrated gasification combined cycle electric utility steam generating unit or *IGCC* means an electric utility steam generating unit meeting the definition of "fossil fuel-fired" that burns a synthetic gas derived from coal and/or solid oil-derived fuel for more than 10.0 percent of the average annual heat input during any 3 consecutive calendar years or for more than 15.0 percent of the annual heat input during any one calendar year in a combined-cycle gas turbine. No solid coal or solid oil-derived fuel is directly burned in the unit during operation.

ISO conditions means a temperature of 288 Kelvin, a relative humidity of 60 percent, and a pressure of 101.3 kilopascals.

Lignite coal means coal that is classified as lignite A or B according to ASTM Method D388–05, "Standard Classification of Coals by Rank" (incorporated by reference, see § 63.14).

Limited-use liquid oil-fired subcategory means an oil-fired electric utility steam generating unit with an annual capacity factor of less than 8 percent of its maximum or nameplate heat input, whichever is greater, averaged over a 24-month block contiguous period commencing April 16, 2015.

Liquid fuel includes, but is not limited to, distillate oil and residual oil.

Monitoring system malfunction or out of control period means any sudden, infrequent, not reasonably preventable failure of the monitoring system to provide valid data. Monitoring system failures that are caused in part by poor maintenance or careless operation are not malfunctions.

Natural gas means a naturally occurring fluid mixture of hydrocarbons (*e.g.,* methane, ethane, or propane) produced in geological formations beneath the Earth's surface that maintains a gaseous state at standard atmospheric temperature and pressure under ordinary conditions. Natural gas contains 20.0 grains or less of total sulfur per 100 standard cubic feet. Additionally, natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 950 and 1,100 Btu per standard cubic foot. Natural gas does not include the following gaseous fuels: landfill gas, digester gas, refinery gas, sour gas, blast furnace gas, coal-derived gas, producer gas, coke oven gas, or any gaseous fuel produced in a process which might result in highly variable sulfur content or heating value.

Natural gas-fired electric utility steam generating unit means an electric utility steam generating unit meeting the definition of "fossil fuel-fired" that is not a coal-fired, oil-fired, or IGCC electric utility steam generating unit and that burns natural gas for more than 10.0 percent of the average annual heat input during any 3 consecutive calendar years or for more than 15.0 percent of the annual heat input during any one calendar year.

Net-electric output means the gross electric sales to the utility power distribution system minus purchased power on a calendar year basis.

Non-continental area means the State of Hawaii, the Virgin Islands, Guam, American Samoa, the Commonwealth of Puerto Rico, or the Northern Mariana Islands.

Non-continental liquid oil-fired subcategory means any oil-fired electric utility steam generating unit that burns liquid oil and is located outside the continental United States.

Non-mercury (Hg) HAP metals means Antimony (Sb), Arsenic (As), Beryllium (Be), Cadmium (Cd), Chromium (Cr), Cobalt (Co), Lead (Pb), Manganese (Mn), Nickel (Ni), and Selenium (Se). *Oil* means crude oil or petroleum or a fuel derived from crude oil or petroleum, including distillate and residual oil, solid oil-derived fuel (*e.g.,* petroleum coke) and gases derived from solid oil-derived fuels (not meeting the definition of natural gas).

Oil-fired electric utility steam generating unit means an electric utility steam generating unit meeting the definition of "fossil fuel-fired" that is not a coal-fired electric utility steam generating unit and that burns oil for more than 10.0 percent of the average annual heat input during any 3 consecutive calendar years or for more than 15.0 percent of the annual heat input during any one calendar year.

Particulate matter or *PM* means any finely divided solid material as measured by the test methods specified under this subpart, or an alternative method.

Pulverized coal (PC) boiler means an EGU in which pulverized coal is introduced into an air stream that carries the coal to the combustion chamber of the EGU where it is fired in suspension.

Residual oil means crude oil, and all fuel oil numbers 4, 5 and 6, as defined by ASTM Method D396–10, "Standard Specification for Fuel Oils" (incorporated by reference, see § 63.14).

Responsible official means responsible official as defined in 40 CFR 70.2.

Shutdown means the cessation of operation of a boiler for any purpose. Shutdown begins either when none of the steam from the boiler is used to generate electricity for sale over the grid or for any other purpose (including on-site use), or at the point of no fuel being fired in the boiler, whichever is earlier. Shutdown ends when there is both no electricity being generated and no fuel being fired in the boiler.

Startup means either the first-ever firing of fuel in a boiler for the purpose of producing electricity, or the firing of fuel in a boiler after a shutdown event for any purpose. Startup ends when any of the steam from the boiler is used to generate electricity for sale over the grid or for any other purpose (including on-site use).

Stationary combustion turbine means all equipment, including but not limited to the turbine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), and any ancillary components and sub-components comprising any simple cycle stationary combustion turbine, any regenerative/recuperative cycle stationary combustion turbine, the combustion turbine portion of any stationary cogeneration cycle combustion system, or the combustion turbine portion of any stationary combined cycle steam/electric generating system. Stationary means that the combustion turbine is not self propelled or intended to be propelled while performing its function. Stationary combustion turbines do not include turbines located at a research or laboratory facility, if research is conducted on the turbine itself and the turbine is not being used to power other applications at the research or laboratory facility.

Steam generating unit means any furnace, boiler, or other device used for combusting fuel for the purpose of producing steam (including fossil-fuel-fired steam generators associated with integrated gasification combined cycle gas turbines; nuclear steam generators are not included).

Stoker means a unit consisting of a mechanically operated fuel feeding mechanism, a stationary or moving grate to support the burning of fuel and admit undergrate air to the fuel, an overfire air system to complete combustion, and an ash discharge system. There are two general types of stokers: underfeed and

overfeed. Overfeed stokers include mass feed and spreader stokers.

Subbituminous coal means coal that is classified as subbituminous A, B, or C according to ASTM Method D388–05, "Standard Classification of Coals by Rank" (incorporated by reference, see § 63.14).

Unit designed for coal > 8,300 Btu/lb subcategory means any coal-fired EGU that is not a coal-fired EGU in the "unit designed for low rank virgin coal" subcategory.

Unit designed for low rank virgin coal subcategory means any coal-fired EGU that is designed to burn and that is burning nonagglomerating virgin coal having a calorific value (moist, mineral matter-free basis) of less than 19,305 kJ/kg (8,300 Btu/lb) that is constructed and operates at or near the mine that produces such coal.

Unit designed to burn solid oil-derived fuel subcategory means any oil-fired EGU that burns solid oil-derived fuel.

Voluntary consensus standards or VCS mean technical standards (*e.g.*, materials specifications, test methods, sampling procedures, business practices) developed or adopted by one or more voluntary consensus bodies. The EPA/OAQPS has by precedent only used VCS that are written in English. Examples of VCS bodies are: American Society of Testing and Materials (ASTM), American Society of Mechanical Engineers (ASME), International Standards Organization (ISO), Standards Australia (AS), British Standards (BS), Canadian Standards (CSA), European Standard (EN or CEN) and German Engineering Standards (VDI). The types of standards that are not considered VCS are standards developed by: the U.S. states, *e.g.*, California (CARB) and Texas (TCEQ); industry groups, such as American Petroleum Institute (API), Gas Processors Association (GPA), and Gas Research Institute (GRI); and other branches of the U.S. government, *e.g.*, Department of Defense (DOD) and Department of Transportation (DOT). This does not preclude EPA from using standards developed by groups that are not VCS bodies within an EPA rule. When this occurs, EPA has done searches and reviews for VCS equivalent to these non-VCS methods.

Wet flue gas desulfurization technology, or *wet FGD, or wet scrubber* means any add-on air pollution control device that is located downstream of the steam generating unit that mixes an aqueous stream or slurry with the exhaust gases from an EGU to control emissions of PM and/or to absorb and neutralize acid gases, such as SO_2 and HCl.

Work practice standard means any design, equipment, work practice, or operational standard, or combination thereof, which is promulgated pursuant to CAA section 112(h).

Tables to Subpart UUUUU of Part 63

TABLE 1 TO SUBPART UUUUU OF PART 63—EMISSION LIMITS FOR NEW OR RECONSTRUCTED EGUS

[As stated in § 63.9991, you must comply with the following applicable emission limits]

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (*e.g.*, specified sampling volume or test run duration) and limitations with the test methods in Table . . .
1. Coal-fired unit not low rank virgin coal.	a. Filterable particulate matter (PM).	7.0E–3 lb/MWh[1]	Collect a minimum of 4 dscm per run.
	OR	OR	
	Total non-Hg HAP metals	6.0E–2 lb/GWh	Collect a minimum of 4 dscm per run.
	OR	OR	
	individual HAP metals:		Collect a minimum of 3 dscm per run.
	Antimony (Sb)	8.0E–3 lb/GW.	
	Arsenic (As)	3.0E–3 lb/GWh.	
	Beryllium (Be)	6.0E–4 lb/GWh.	
	Cadmium (Cd)	4.0E–4 lb/GWh.	
	Chromium (Cr)	7.0E–3 lb/GWh.	
	Cobalt (Co)	2.0E–3 lb/GWh.	
	Lead (Pb)	2.0E–3 lb/GWh.	
	Manganese (Mn)	4.0E–3 lb/GWh.	
	Nickel (Ni)	4.0E–2 lb/GWh.	
	Selenium (Se)	6.0E–3 lb/GWh.	
	b. Hydrogen chloride (HC1)	4.0E–4 lb/MWh	For Method 26A, collect a minimum of 3 dscm per run. For ASTM D6348–03[2] or Method 320, sample for a minimum of 1 hour.
	OR.		
	Sulfur dioxide (SO_2)[3]	4.0E–1 lb/MWh	SO_2 CEMS.
	c. Mercury (Hg)	2.0E–4 lb/GWh	Hg CEMS or sorbent trap monitoring system only.
2. Coal-fired units low rank virgin coal.	a. Filterable particulate matter (PM).	7.0E–3 lb/MWh[1]	Collect a minimum of 4 dscm per run.
	OR	OR	
	Total non-Hg HAP metals	6.0E–2 lb/GWh	Collect a minimum of 4 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 3 dscm per run.
	Antimony (Sb)	8.0E–3 lb/GWh.	
	Arsenic (As)	3.0E–3 lb/GWh.	

TABLE 1 TO SUBPART UUUUU OF PART 63—EMISSION LIMITS FOR NEW OR RECONSTRUCTED EGUs—Continued

[As stated in § 63.9991, you must comply with the following applicable emission limits]

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (*e.g.*, specified sampling volume or test run duration) and limitations with the test methods in Table . . .
	Beryllium (Be)	6.0E–4 lb/GWh.	
	Cadmium (Cd)	4.0E–4 lb/GWh.	
	Chromium (Cr)	7.0E–3 lb/GWh.	
	Cobalt (Co)	2.0E–3 lb/GWh.	
	Lead (Pb)	2.0E–3 lb/GWh.	
	Manganese (Mn)	4.0E–3 lb/GWh.	
	Nickel (Ni)	4.0E–2 lb/GWh.	
	Selenium (Se)	6.0E–3 lb/GWh.	
	b. Hydrogen chloride (HCl)	4.0E–4 lb/MWh	For Method 26A, collect a minimum of 3 dscm per run. For ASTM D6348–03[2] or Method 320, sample for a minimum of 1 hour.
	OR		
	Sulfur dioxide (SO_2)[3]	4.0E–1 lb/MWh	SO_2 CEMS.
	c. Mercury (Hg)	4.0E–2 lb/GWh	Hg CEMS or sorbent trap monitoring system only.
3. IGCC unit	a. Filterable particulate matter (PM).	7.0E–2 lb/MWh[4] 9.0E–2 lb/MWh[5]	Collect a minimum of 1 dscm per run.
	OR	OR	
	Total non-Hg HAP metals	4.0E–1 lb/GWh	Collect a minimum of 1 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 2 dscm per run.
	Antimony (Sb)	2.0E–2 lb/GWh.	
	Arsenic (As)	2.0E–2 lb/GWh.	
	Beryllium (Be)	1.0E–3 lb/GWh.	
	Cadmium (Cd)	2.0E–3 lb/GWh.	
	Chromium (Cr)	4.0E–2 lb/GWh.	
	Cobalt (Co)	4.0E–3 lb/GWh.	
	Lead (Pb)	9.0E–3 lb/GWh.	
	Manganese (Mn)	2.0E–2 lb/GWh.	
	Nickel (Ni)	7.0E–2 lb/GWh.	
	Selenium (Se)	3.0E–1 lb/GWh.	
	b. Hydrogen chloride (HCl)	2.0E–3 lb/MWh	For Method 26A, collect a minimum of 1 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348–03[2] or Method 320, sample for a minimum of 1 hour.
	OR		
	Sulfur dioxide (SO_2)[3]	4.0E–1 lb/MWh	SO^2 CEMS.
	c. Mercury (Hg)	3.0E–3 lb/GWh	Hg CEMS or sorbent trap monitoring system only.
4. Liquid oil-fired unit—continental (excluding limited-use liquid oil-fired subcategory units).	a. Filterable particulate matter (PM).	7.0E–2 lb/MWh[1]	Collect a minimum of 1 dscm per run.
	OR	OR	
	Total HAP metals	2.0E–4 lb/MWh	Collect a minimum of 2 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 2 dscm per run.
	Antimony (Sb)	1.0E–2 lb/GWh.	
	Arsenic (As)	3.0E–3 lb/GWh.	
	Beryllium (Be)	5.0E–4 lb/GWh.	
	Cadmium (Cd)	2.0E–4 lb/GWh.	
	Chromium (Cr)	2.0E–2 lb/GWh.	
	Cobalt (Co)	3.0E–2 lb/GWh.	
	Lead (Pb)	8.0E–3 lb/GWh.	
	Manganese (Mn)	2.0E–2 lb/GWh.	
	Nickel (Ni)	9.0E–2 lb/GWh.	
	Selenium (Se)	2.0E–2 lb/GWh.	

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TABLE 1 TO SUBPART UUUUU OF PART 63—EMISSION LIMITS FOR NEW OR RECONSTRUCTED EGUS—Continued

[As stated in § 63.9991, you must comply with the following applicable emission limits]

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (*e.g.*, specified sampling volume or test run duration) and limitations with the test methods in Table . . .
	Mercury (Hg)	1.0E–4 lb/GWh	For Method 30B sample volume determination (Section 8.2.4), the estimated Hg concentration should nominally be <½ the standard.
	b. Hydrogen chloride (HCl)	4.0E–4 lb/MWh	For Method 26A, collect a minimum of 3 dscm per run. For ASTM D6348–03[2] or Method 320, sample for a minimum of 1 hour.
	c. Hydrogen fluoride (HF)	4.0E–4 lb/MWh	For Method 26A, collect a minimum of 3 dscm per run. For ASTM D6348–03[2] or Method 320, sample for a minimum of 1 hour.
5. Liquid oil-fired unit—non-continental (excluding limited-use liquid oil-fired subcategory units).	a. Filterable particulate matter (PM).	2.0E–1 lb/MWh[1]	Collect a minimum of 1 dscm per run.
	OR	OR	
	Total HAP metals	7.0E–3 lb/MWh	Collect a minimum of 1 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 3 dscm per run.
	Antimony (Sb)	8.0E–3 lb/GWh.	
	Arsenic (As)	6.0E–2 lb/GWh.	
	Beryllium (Be)	2.0E–3 lb/GWh.	
	Cadmium (Cd)	2.0E–3 lb/GWh.	
	Chromium (Cr)	2.0E–2 lb/GWh.	
	Cobalt (Co)	3.0E–1 lb/GWh.	
	Lead (Pb)	3.0E–2 lb/GWh.	
	Manganese (Mn)	1.0E–1 lb/GWh.	
	Nickel (Ni)	4.1E–0 lb/GWh.	
	Selenium (Se)	2.0E–2 lb/GWh.	
	Mercury (Hg)	4.0E–4 lb/GWh	For Method 30B sample volume determination (Section 8.2.4), the estimated Hg concentration should nominally be < ½ the standard.
	b. Hydrogen chloride (HCl)	2.0E–3 lb/MWh	For Method 26A, collect a minimum of 1 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348–03[2] or Method 320, sample for a minimum of 1 hour
	c. Hydrogen fluoride (HF)	5.0E–4 lb/MWh	For Method 26A, collect a minimum of 3 dscm per run. For ASTM D6348–03[2] or Method 320, sample for a minimum of 1 hour.
6. Solid oil-derived fuel-fired unit ...	a. Filterable particulate matter (PM).	2.0E–2 lb/MWh[1]	Collect a minimum of 1 dscm per run.
	OR	OR	
	Total non-Hg HAP metals	6.0E–1 lb/GWh	Collect a minimum of 1 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 3 dscm per run.
	Antimony (Sb)	8.0E–3 lb/GWh.	
	Arsenic (As)	3.0E–3 lb/GWh.	
	Beryllium (Be)	6.0E–4 lb/GWh.	
	Cadmium (Cd)	7.0E–4 lb/GWh.	
	Chromium (Cr)	6.0E–3 lb/GWh.	
	Cobalt (Co)	2.0E–3 lb/GWh.	

TABLE 1 TO SUBPART UUUUU OF PART 63—EMISSION LIMITS FOR NEW OR RECONSTRUCTED EGUS—Continued

[As stated in § 63.9991, you must comply with the following applicable emission limits]

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (*e.g.*, specified sampling volume or test run duration) and limitations with the test methods in Table . . .
	Lead (Pb)	2.0E–2 lb/GWh.	
	Manganese (Mn)	7.0E–3 lb/GWh.	
	Nickel (Ni)	4.0E–2 lb/GWh.	
	Selenium (Se)	6.0E–3 lb/GWh.	
	b. Hydrogen chloride (HCl)	4.0E–4 lb/MWh	For Method 26A, collect a minimum of 3 dscm per run. For ASTM D6348–03 [2] or Method 320, sample for a minimum of 1 hour.
	OR		
	Sulfur dioxide (SO_2) [3]	4.0E–1 lb/MWh	SO_2 CEMS.
	c. Mercury (Hg)	2.0E–3 lb/GWh	Hg CEMS or Sorbent trap monitoring system only.

[1] Gross electric output.
[2] Incorporated by reference, see § 63.14.
[3] You may not use the alternate SO_2 limit if your EGU does not have some form of FGD system and SO_2 CEMS installed.
[4] Duct burners on syngas; gross electric output.
[5] Duct burners on natural gas; gross electric output

TABLE 2 TO SUBPART UUUUU OF PART 63—EMISSION LIMITS FOR EXISTING EGUS

[As stated in § 63.9991, you must comply with the following applicable emission limits] [1]

If your EGU is in this subcategory	For the following pollutants	You must meet the following emission limits and work practice standards	Using these requirements, as appropriate (*e.g.*, specified sampling volume or test run duration) and limitations with the test methods in Table 5
1. Coal-fired unit not low rank virgin coal.	a. Filterable particulate matter (PM).	3.0E–2 lb/MMBtu or 3.0E–1 lb/MWh [2].	Collect a minimum of 1 dscm per run.
	OR	OR	
	Total non-Hg HAP metals	5.0E–5 lb/MMBtu or 5.0E–1 lb/GWh.	Collect a minimum of 1 dscm per run.
	OR	OR	
	Individual HAP metals		
	Antimony (Sb)	8.0E–1 lb/TBtu or 8.0E–3 lb/GWh.	
	Arsenic (As)	1.1E0 lb/TBtu or 2.0E–2 lb/GWh.	
	Beryllium (Be)	2.0E–1 lb/TBtu or 2.0E–3 lb/GWh.	
	Cadmium (Cd)	3.0E–1 lb/TBtu or 3.0E–3 lb/GWh.	
	Chromium (Cr)	2.8E0 lb/TBtu or 3.0E–2 lb/GWh.	
	Cobalt (Co)	8.0E–1 lb/TBtu or 8.0E–3 lb/GWh.	
	Lead (Pb)	1.2E0 lb/TBtu or 2.0E–2 lb/GWh.	
	Manganese (Mn)	4.0E0 lb/TBtu or 5.0E–2 lb/GWh.	
	Nickel (Ni)	3.5E0 lb/TBtu or 4.0E–2 lb/GWh.	
	Selenium (Se)	5.0E0 lb/TBtu or 6.0E–2 lb/GWh.	
	b. Hydrogen chloride (HCl)	2.0E–3 lb/MMBtu or 2.0E–2 lb/MWh.	For Method 26A, collect a minimum of 0.75 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348–03 [3] or Method 320, sample for a minimum of 1 hour.
	OR		
	Sulfur dioxide (SO_2) [4]	2.0E–1 lb/MMBtu or 1.5E0 lb/MWh.	SO_2 CEMS.
	c. Mercury (Hg)	1.2E0 lb/TBtu or 1.3E–2 lb/GWh ..	LEE Testing for 30 days with 10 days maximum per Method 30B run or Hg CEMS or sorbent trap monitoring system only.
2. Coal-fired unit low rank virgin coal.	a. Filterable particulate matter (PM).	3.0E–2 lb/MMBtu or 3.0E–1 lb/MWh2.	Collect a minimum of 1 dscm per run.
	OR	OR	
	Total non-Hg HAP metals	5.0E–5 lb/MMBtu or 5.0E–1 lb/GWh.	Collect a minimum of 1 dscm per run.
	OR	OR	

TABLE 2 TO SUBPART UUUUU OF PART 63—EMISSION LIMITS FOR EXISTING EGUs—Continued

[As stated in § 63.9991, you must comply with the following applicable emission limits] [1]

If your EGU is in this subcategory	For the following pollutants	You must meet the following emission limits and work practice standards	Using these requirements, as appropriate (*e.g.*, specified sampling volume or test run duration) and limitations with the test methods in Table 5
	Individual HAP metals:	.....	Collect a minimum of 3 dscm per run.
	Antimony (Sb)	8.0E–1 lb/TBtu or 8.0E–3 lb/GWh.	
	Arsenic (As)	1.1E0 lb/TBtu or 2.0E–2 lb/GWh.	
	Beryllium (Be)	2.0E–1 lb/TBtu or 2.0E–3 lb/GWh.	
	Cadmium (Cd)	3.0E–1 lb/TBtu or 3.0E–3 lb/GWh.	
	Chromium (Cr)	2.8E0 lb/TBtu or 3.0E–2 lb/GWh.	
	Cobalt (Co)	8.0E–1 lb/TBtu or 8.0E–3 lb/GWh.	
	Lead (Pb)	1.2E0 lb/TBtu or 2.0E–2 lb/GWh.	
	Manganese (Mn)	4.0E0 lb/TBtu or 5.0E–2 lb/GWh.	
	Nickel (Ni)	3.5E0 lb/TBtu or 4.0E–2 lb/GWh.	
	Selenium (Se)	5.0E0 lb/TBtu or 6.0E–2 lb/GWh.	
	b. Hydrogen chloride (HCl)	2.0E–3 lb/MMBtu or 2.0E–2 lb/MWh.	For Method 26A, collect a minimum of 0.75 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348–03 [3] or Method 320, sample for a minimum of 1 hour.
	OR		
	Sulfur dioxide (SO_2) [4]	2.0E–1 lb/MMBtu or 1.5E0 lb/MWh.	SO_2 CEMS.
	c. Mercury (Hg)	4.0E0 lb/TBtu or 4.0E–2 lb/GWh ..	LEE Testing for 30 days with 10 days maximum per Method 30B run or Hg CEMS or sorbent trap monitoring system only.
3. IGCC unit	a. Filterable particulate matter (PM).	4.0E–2 lb/MMBtu or 4.0E–1 lb/MWh2.	Collect a minimum of 1 dscm per run.
	OR	OR	
	Total non-Hg HAP metals	6.0E–5 lb/MMBtu or 5.0E–1 lb/GWh.	Collect a minimum of 1 dscm per run.
	OR	OR	
	Individual HAP metals:	.....	Collect a minimum of 2 dscm per run.
	Antimony (Sb)	1.4E0 lb/TBtu or 2.0E–2 lb/GWh.	
	Arsenic (As)	1.5E0 lb/TBtu or 2.0E–2 lb/GWh.	
	Beryllium (Be)	1.0E–1 lb/TBtu or 1.0E–3 lb/GWh.	
	Cadmium (Cd)	1.5E–1 lb/TBtu or 2.0E–3 lb/GWh.	
	Chromium (Cr)	2.9E0 lb/TBtu or 3.0E–2 lb/GWh.	
	Cobalt (Co)	1.2E0 lb/TBtu or 2.0E–2 lb/GWh.	
	Lead (Pb)	1.9E+2 lb/MMBtu or 1.8E0 lb/MWh.	
	Manganese (Mn)	2.5E0 lb/TBtu or 3.0E–2 lb/GWh.	
	Nickel (Ni)	6.5E0 lb/TBtu or 7.0E–2 lb/GWh.	
	Selenium (Se)	2.2E+1 lb/TBtu or 3.0E–1 lb/GWh.	
	b. Hydrogen chloride (HCl)	5.0E–4 lb/MMBtu or 5.0E–3 lb/MWh.	For Method 26A, collect a minimum of 1 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348–03 [3] or Method 320, sample for a minimum of 1 hour.
	c. Mercury (Hg)	2.5E0 lb/TBtu or 3.0E–2 lb/GWh ..	LEE Testing for 30 days with 10 days maximum per Method 30B run or Hg CEMS or sorbent trap monitoring system only.
4. Liquid oil-fired unit—continental (excluding limited-use liquid oil-fired subcategory units).	a. Filterable particulate matter (PM).	3.0E–2 lb/MMBtu or 3.0E–1 lb/MWh2.	Collect a minimum of 1 dscm per run.
	OR	OR	
	Total HAP metals	8.0E–4 lb/MMBtu or 8.0E–3 lb/MWh.	Collect a minimum of 1 dscm per run.
	OR	OR	
	Individual HAP metals		Collect a minimum of 1 dscm per run.

TABLE 2 TO SUBPART UUUUU OF PART 63—EMISSION LIMITS FOR EXISTING EGUs—Continued

[As stated in § 63.9991, you must comply with the following applicable emission limits] [1]

If your EGU is in this subcategory	For the following pollutants	You must meet the following emission limits and work practice standards	Using these requirements, as appropriate (*e.g.*, specified sampling volume or test run duration) and limitations with the test methods in Table 5
	Antimony (Sb)	1.3E+1 lb/TBtu or 2.0E–1 lb/GWh.	
	Arsenic (As)	2.8E0 lb/TBtu or 3.0E–2 lb/GWh.	
	Beryllium (Be)	2.0E–1 lb/TBtu or 2.0E–3 lb/GWh.	
	Cadmium (Cd)	3.0E–1 lb/TBtu or 2.0E–3 lb/GWh.	
	Chromium (Cr)	5.5E0 lb/TBtu or 6.0E–2 lb/GWh.	
	Cobalt (Co)	2.1E+1 lb/TBtu or 3.0E–1 lb/GWh.	
	Lead (Pb)	8.1E0 lb/TBtu or 8.0E–2 lb/GWh.	
	Manganese (Mn)	2.2E+1 lb/TBtu or 3.0E–1 lb/GWh.	
	Nickel (Ni)	1.1E+2 lb/TBtu or 1.1E0 lb/GWh.	
	Selenium (Se)	3.3E0 lb/TBtu or 4.0E–2 lb/GWh.	
	Mercury (Hg)	2.0E–1 lb/TBtu or 2.0E–3 lb/GWh	For Method 30B sample volume determination (Section 8.2.4), the estimated Hg concentration should nominally be < ½ the standard.
	b. Hydrogen chloride (HCl)	2.0E–3 lb/MMBtu or 1.0E–2 lb/MWh.	For Method 26A, collect a minimum of 1 dscm per Run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348–03 [3] or Method 320, sample for a minimum of 1 hour.
	c. Hydrogen fluoride (HF)	4.0E–4 lb/MMBtu or 4.0E–3 lb/MWh.	For Method 26A, collect a minimum of 1 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348–03 [3] or Method 320, sample for a minimum of 1 hour.
5. Liquid oil-fired unit—non-continental (excluding limited-use liquid oil-fired subcategory units).	a. Filterable particulate matter (PM).	3.0E–2 lb/MMBtu or 3.0E–1 lb/MWh2.	Collect a minimum of 1 dscm per run.
	OR	OR	
	Total HAP metals	6.0E–4 lb/MMBtu or 7.0E–3 lb/MWh.	Collect a minimum of 1 dscm per run.
	OR	OR	
	Individual HAP metals		Collect a minimum of 2 dscm per run.
	Antimony (Sb)	2.2E0 lb/TBtu or 2.0E–2 lb/GWh.	
	Arsenic (As)	4.3E0 lb/TBtu or 8.0E–2 lb/GWh.	
	Beryllium (Be)	6.0E–1 lb/TBtu or 3.0E–3 lb/GWh.	
	Cadmium (Cd)	3.0E–1 lb/TBtu or 3.0E–3 lb/GWh.	
	Chromium (Cr)	3.1E+1 lb/TBtu or 3.0E–1 lb/GWh.	
	Cobalt (Co)	1.1E+2 lb/TBtu or 1.4E0 lb/GWh.	
	Lead (Pb)	4.9E0 lb/TBtu or 8.0E–2 lb/GWh.	
	Manganese (Mn)	2.0E+1 lb/TBtu or 3.0E–1 lb/GWh.	
	Nickel (Ni)	4.7E+2 lb/TBtu or 4.1E0 lb/GWh.	
	Selenium (Se)	9.8E0 lb/TBtu or 2.0E–1 lb/GWh.	
	Mercury (Hg)	4.0E–2 lb/TBtu or 4.0E–4 lb/GWh	For Method 30B sample volume determination (Section 8.2.4), the estimated Hg concentration should nominally be < ½ the standard.
	Hydrogen chloride (HCl)	2.0E–4 lb/MMBtu or 2.0E–3 lb/MWh.	For Method 26A, collect a minimum of 1 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348–03 [3] or Method 320, sample for a minimum of 2 hours.
	c. Hydrogen fluoride (HF)	6.0E–5 lb/MMBtu or 5.0E–4 lb/MWh.	For Method 26A, collect a minimum of 3 dscm per run. For ASTM D6348–03 [3] or Method 320, sample for a minimum of 2 hours.

TABLE 2 TO SUBPART UUUUU OF PART 63—EMISSION LIMITS FOR EXISTING EGUS—Continued

[As stated in § 63.9991, you must comply with the following applicable emission limits] [1]

If your EGU is in this subcategory	For the following pollutants	You must meet the following emission limits and work practice standards	Using these requirements, as appropriate (*e.g.*, specified sampling volume or test run duration) and limitations with the test methods in Table 5
6. Solid oil-derived fuel-fired unit ..	a. Filterable particulate matter (PM).	8.0E–3 lb/MMBtu or 9.0E–2 lb/MWh2.	Collect a minimum of 1 dscm per run.
	OR	OR	
	Total non-Hg HAP metals	4.0E–5 lb/MMBtu or 6.0E–1 lb/GWh.	Collect a minimum of 1 dscm per run.
	OR	OR	
	Individual HAP metals	.....	Collect a minimum of 3 dscm per run.
	Antimony (Sb)	8.0E–1 lb/TBtu or 8.0E–3 lb/GWh.	
	Arsenic (As)	3.0E–1 lb/TBtu or 5.0E–3 lb/GWh.	
	Beryllium (Be)	6.0E–2 lb/TBtu or 6.0E–4 lb/GWh.	
	Cadmium (Cd)	3.0E–1 lb/TBtu or 4.0E–3 lb/GWh.	
	Chromium (Cr)	8.0E–1 lb/TBtu or 2.0E–2 lb/GWh.	
	Cobalt (Co)	1.1E0 lb/TBtu or 2.0E–2 lb/GWh.	
	Lead (Pb)	8.0E–1 lb/TBtu or 2.0E–2 lb/GWh.	
	Manganese (Mn)	2.3E0 lb/TBtu or 4.0E–2 lb/GWh.	
	Nickel (Ni)	9.0E0 lb/TBtu or 2.0E–1 lb/GWh.	
	Selenium (Se)	1.2E0 lb/TBtu 2.0E–2 lb/GWh.	
	b. Hydrogen chloride (HCl)	5.0E–3 lb/MMBtu or 8.0E–2 lb/MWh.	For Method 26A, collect a minimum of 0.75 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348–03 [3] or Method 320, sample for a minimum of 1 hour.
	OR		
	Sulfur dioxide (SO_2) [4]	3.0E–1 lb/MMBtu or 2.0E0 lb/MWh.	SO_2 CEMS.
	c. Mercury (Hg)	2.0E–1 lb/TBtu or 2.0E–3 lb/GWh	LEE Testing for 30 days with 10 days maximum per Method 30B run or Hg CEMS or Sorbent trap monitoring system only.

[1] For LEE emissions testing for total PM, total HAP metals, individual HAP metals, HCl, and HF, the required minimum sampling volume must be increased nominally by a factor of two.
[2] Gross electric output.
[3] Incorporated by reference, see § 63.14.
[4] You may not use the alternate SO_2 limit if your EGU does not have some form of FGD system and SO_2 CEMS installed.

TABLE 3 TO SUBPART UUUUU OF PART 63—WORK PRACTICE STANDARDS

[As stated in §§ 63.9991, you must comply with the following applicable work practice standards]

If your EGU is . . .	You must meet the following . . .
1. An existing EGU	Conduct a tune-up of the EGU burner and combustion controls at least each 36 calendar months, or each 48 calendar months if neural network combustion optimization software is employed, as specified in § 63.10021(e).
2. A new or reconstructed EGU	Conduct a tune-up of the EGU burner and combustion controls at least each 36 calendar months, or each 48 calendar months if neural network combustion optimization software is employed, as specified in § 63.10021(e).
3. A coal-fired, liquid oil-fired, or solid oil-derived fuel-fired EGU during startup.	You must operate all CMS during startup. Startup means either the first-ever firing of fuel in a boiler for the purpose of producing electricity, or the firing of fuel in a boiler after a shutdown event for any purpose. Startup ends when any of the steam from the boiler is used to generate electricity for sale over the grid or for any other purpose (including on site use). For startup of a unit, you must use clean fuels, either natural gas or distillate oil or a combination of clean fuels for ignition. Once you convert to firing coal, residual oil, or solid oil-derived fuel, you must engage all of the applicable control technologies except dry scrubber and SCR. You must start your dry scrubber and SCR systems, if present, appropriately to comply with relevant standards applicable during normal operation. You must comply with all applicable emissions limits at all times except for periods that meet the definitions of startup and shutdown in this subpart. You must keep records during periods of startup. You must provide reports concerning activities and periods of startup, as specified in § 63.10011(g) and § 63.10021(h) and (i).

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TABLE 3 TO SUBPART UUUUU OF PART 63—WORK PRACTICE STANDARDS—Continued

[As stated in §§ 63.9991, you must comply with the following applicable work practice standards]

If your EGU is . . .	You must meet the following . . .
4. A coal-fired, liquid oil-fired, or solid oil-derived fuel-fired EGU during shutdown.	You must operate all CMS during shutdown. Shutdown means the cessation of operation of a boiler for any purpose. Shutdown begins either when none of the steam from the boiler is used to generate electricity for sale over the grid or for any other purpose (including on-site use) or at the point of no fuel being fired in the boiler. Shutdown ends when there is both no electricity being generated and no fuel being fired in the boiler. During shutdown, you must operate all applicable control technologies while firing coal, residual oil, or solid oil-derived fuel. You must comply with all applicable emissions limits at all times except for periods that meet the definitions of startup and shutdown in this subpart. You must keep records during periods of startup. You must provide reports concerning activities and periods of startup, as specified in § 63.10011(g) and § 63.10021(h) and (i).

TABLE 4 TO SUBPART UUUUU OF PART 63—OPERATING LIMITS FOR EGUS

[As stated in § 63.9991, you must comply with the applicable operating limits]

If you demonstrate compliance using . . .	You must meet these operating limits . . .
1. PM CPMS	Maintain the 30-boiler operating day rolling average PM CPMS output at or below the highest 1-hour average measured during the most recent performance test demonstrating compliance with the filterable PM, total non-mercury HAP metals (total HAP metals, for liquid oil-fired units), or individual non-mercury HAP metals (individual HAP metals including Hg, for liquid oil-fired units) emissions limitation(s).

TABLE 5 TO SUBPART UUUUU OF PART 63—PERFORMANCE TESTING REQUIREMENTS

[As stated in § 63.10007, you must comply with the following requirements for performance testing for existing, new or reconstructed affected sources [1]]

To conduct a performance test for the following pollutant . . .	Using . . .	You must perform the following activities, as applicable to your input- or output-based emission limit . . .	Using [2] . . .
1. Filterable Particulate matter (PM).	Emissions Testing	a. Select sampling ports location and the number of traverse points.	Method 1 at Appendix A–1 to part 60 of this chapter.
		b. Determine velocity and volumetric flow-rate of the stack gas.	Method 2, 2A, 2C, 2F, 2G or 2H at Appendix A–1 or A–2 to part 60 of this chapter.
		c. Determine oxygen and carbon dioxide concentrations of the stack gas.	Method 3A or 3B at Appendix A–2 to part 60 of this chapter, or ANSI/ASME PTC 19.10–1981.[3]
		d. Measure the moisture content of the stack gas.	Method 4 at Appendix A–3 to part 60 of this chapter.
		e. Measure the filterable PM concentration	Method 5 at Appendix A–3 to part 60 of this chapter. For positive pressure fabric filters, Method 5D at Appendix A–3 to part 60 of this chapter for filterable PM emissions. Note that the Method 5 front half temperature shall be 160 ° ± 14 °C (320 ° ± 25 °F).
		f. Convert emissions concentration to lb/MMBtu or lb/MWh emissions rates.	Method 19 F-factor methodology at Appendix A–7 to part 60 of this chapter, or calculate using mass emissions rate and electrical output data (see § 63.10007(e)).
	OR	OR	
	PM CEMS	a. Install, certify, operate, and maintain the PM CEMS.	Performance Specification 11 at Appendix B to part 60 of this chapter and Procedure 2 at Appendix F to Part 60 of this chapter.
		b. Install, certify, operate, and maintain the diluent gas, flow rate, and/or moisture monitoring systems.	Part 75 of this chapter and §§ 63.10010(a), (b), (c), and (d).
		c. Convert hourly emissions concentrations to 30 boiler operating day rolling average lb/MMBtu or lb/MWh emissions rates.	Method 19 F-factor methodology at Appendix A–7 to part 60 of this chapter, or calculate using mass emissions rate and electrical output data (see § 63.10007(e)).
2. Total or individual non-Hg HAP metals.	Emissions Testing	a. Select sampling ports location and the number of traverse points.	Method 1 at Appendix A–1 to part 60 of this chapter.
		b. Determine velocity and volumetric flow-rate of the stack gas.	Method 2, 2A, 2C, 2F, 2G or 2H at Appendix A–1 or A–2 to part 60 of this chapter.

TABLE 5 TO SUBPART UUUUU OF PART 63—PERFORMANCE TESTING REQUIREMENTS—Continued

[As stated in § 63.10007, you must comply with the following requirements for performance testing for existing, new or reconstructed affected sources [1]]

To conduct a performance test for the following pollutant . . .	Using . . .	You must perform the following activities, as applicable to your input- or output-based emission limit . . .	Using [2] . . .
		c. Determine oxygen and carbon dioxide concentrations of the stack gas.	Method 3A or 3B at Appendix A–2 to part 60 of this chapter, or ANSI/ASME PTC 19.10–1981.[3]
		d. Measure the moisture content of the stack gas.	Method 4 at Appendix A–3 to part 60 of this chapter.
		e. Measure the HAP metals emissions concentrations and determine each individual HAP metals emissions concentration, as well as the total filterable HAP metals emissions concentration and total HAP metals emissions concentration.	Method 29 at Appendix A–8 to part 60 of this chapter. For liquid oil-fired units, Hg is included in HAP metals and you may use Method 29, Method 30B at Appendix A–8 to part 60 of this chapter; for Method 29, you must report the front half and back half results separately.
		f. Convert emissions concentrations (individual HAP metals, total filterable HAP metals, and total HAP metals) to lb/MMBtu or lb/MWh emissions rates.	Method 19 F-factor methodology at Appendix A–7 to part 60 of this chapter, or calculate using mass emissions rate and electrical output data (see § 63.10007(e)).
3. Hydrogen chloride (HCl) and hydrogen fluoride (HF).	Emissions Testing	a. Select sampling ports location and the number of traverse points.	Method 1 at Appendix A–1 to part 60 of this chapter.
		b. Determine velocity and volumetric flow-rate of the stack gas.	Method 2, 2A, 2C, 2F, 2G or 2H at Appendix A–1 or A–2 to part 60 of this chapter.
		c. Determine oxygen and carbon dioxide concentrations of the stack gas.	Method 3A or 3B at Appendix A–2 to part 60 of this chapter, or ANSI/ASME PTC 19.10–1981.[3]
		d. Measure the moisture content of the stack gas.	Method 4 at Appendix A–3 to part 60 of this chapter.
		e. Measure the HCl and HF emissions concentrations.	Method 26 or Method 26A at Appendix A–8 to part 60 of this chapter or Method 320 at Appendix A to part 63 of this chapter or ASTM 6348–03[3] with (1) additional quality assurance measures in footnote [4] and (2) spiking levels nominally no greater than two times the level corresponding to the applicable emission limit. Method 26A must be used if there are entrained water droplets in the exhaust stream.
		f. Convert emissions concentration to lb/MMBtu or lb/MWh emissions rates.	Method 19 F-factor methodology at Appendix A–7 to part 60 of this chapter, or calculate using mass emissions rate and electrical output data (see § 63.10007(e)).
	OR	OR	
	HCl and/or HF CEMS	a. Install, certify, operate, and maintain the HCl or HF CEMS.	Appendix B of this subpart.
		b. Install, certify, operate, and maintain the diluent gas, flow rate, and/or moisture monitoring systems.	Part 75 of this chapter and §§ 63.10010(a), (b), (c), and (d).
		c. Convert hourly emissions concentrations to 30 boiler operating day rolling average lb/MMBtu or lb/MWh emissions rates.	Method 19 F-factor methodology at Appendix A–7 to part 60 of this chapter, or calculate using mass emissions rate and electrical output data (see § 63.10007(e)).
4. Mercury (Hg)	Emissions Testing	a. Select sampling ports location and the number of traverse points.	Method 1 at Appendix A–1 to part 60 of this chapter or Method 30B at Appendix A–8 for Method 30B point selection.
		b. Determine velocity and volumetric flow-rate of the stack gas.	Method 2, 2A, 2C, 2F, 2G or 2H at Appendix A–1 or A–2 to part 60 of this chapter.
		c. Determine oxygen and carbon dioxide concentrations of the stack gas.	Method 3A or 3B at Appendix A–1 to part 60 of this chapter, or ANSI/ASME PTC 19.10–1981.[3]
		d. Measure the moisture content of the stack gas.	Method 4 at Appendix A–3 to part 60 of this chapter.
		e. Measure the Hg emission concentration	Method 30B at Appendix A–8 to part 60 of this chapter, ASTM D6784[3], or Method 29 at Appendix A–8 to part 60 of this chapter; for Method 29, you must report the front half and back half results separately.

TABLE 5 TO SUBPART UUUUU OF PART 63—PERFORMANCE TESTING REQUIREMENTS—Continued

[As stated in § 63.10007, you must comply with the following requirements for performance testing for existing, new or reconstructed affected sources [1]]

To conduct a performance test for the following pollutant . . .	Using . . .	You must perform the following activities, as applicable to your input- or output-based emission limit . . .	Using [2] . . .
		f. Convert emissions concentration to lb/TBtu or lb/GWh emission rates.	Method 19 F-factor methodology at Appendix A–7 to part 60 of this chapter, or calculate using mass emissions rate and electrical output data (see § 63.10007(e)).
	OR	OR	
	Hg CEMS	a. Install, certify, operate, and maintain the CEMS.	Sections 3.2.1 and 5.1 of Appendix A of this subpart.
		b. Install, certify, operate, and maintain the diluent gas, flow rate, and/or moisture monitoring systems.	Part 75 of this chapter and §§ 63.10010(a), (b), (c), and (d).
		c. Convert hourly emissions concentrations to 30 boiler operating day rolling average lb/TBtu or lb/GWh emissions rates.	Section 6 of Appendix A to this subpart.
	OR	OR	
	Sorbent trap monitoring system.	a. Install, certify, operate, and maintain the sorbent trap monitoring system.	Sections 3.2.2 and 5.2 of Appendix A to this subpart.
		b. Install, operate, and maintain the diluent gas, flow rate, and/or moisture monitoring systems.	Part 75 of this chapter and §§ 63.10010(a), (b), (c), and (d).
		c. Convert emissions concentrations to 30 boiler operating day rolling average lb/TBtu or lb/GWh emissions rates.	Section 6 of Appendix A to this subpart.
	OR	OR	
	LEE testing	a. Select sampling ports location and the number of traverse points.	Single point located at the 10% centroidal area of the duct at a port location per Method 1 at Appendix A–1 to part 60 of this chapter or Method 30B at Appendix A–8 for Method 30B point selection.
		b. Determine velocity and volumetric flow-rate of the stack gas.	Method 2, 2A, 2C, 2F, 2G, or 2H at Appendix A–1 or A–2 to part 60 of this chapter or flow monitoring system certified per Appendix A of this subpart.
		c. Determine oxygen and carbon dioxide concentrations of the stack gas.	Method 3A or 3B at Appendix A–1 to part 60 of this chapter, or ANSI/ASME PTC 19.10–1981,[3] or diluent gas monitoring systems certified according to Part 75 of this chapter.
		d. Measure the moisture content of the stack gas.	Method 4 at Appendix A–3 to part 60 of this chapter, or moisture monitoring systems certified according to part 75 of this chapter.
		e. Measure the Hg emission concentration	Method 30B at Appendix A–8 to part 60 of this chapter; perform a 30 operating day test, with a maximum of 10 operating days per run (*i.e.*, per pair of sorbent traps) or sorbent trap monitoring system or Hg CEMS certified per Appendix A of this subpart.
		f. Convert emissions concentrations from the LEE test to lb/TBtu or lb/GWh emissions rates.	Method 19 F-factor methodology at Appendix A–7 to part 60 of this chapter, or calculate using mass emissions rate and electrical output data (see § 63.10007(e)).
		g. Convert average lb/TBtu or lb/GWh Hg emission rate to lb/year, if you are attempting to meet the 22.0 lb/year threshold.	Potential maximum annual heat input in TBtu or potential maximum electricity generated in GWh.
5. Sulfur dioxide (SO_2)	SO_2 CEMS	a. Install, certify, operate, and maintain the CEMS.	Part 75 of this chapter and §§ 63.10010(a) and (f).
		b. Install, operate, and maintain the diluent gas, flow rate, and/or moisture monitoring systems.	Part 75 of this chapter and §§ 63.10010(a), (b), (c), and (d).
		c. Convert hourly emissions concentrations to 30 boiler operating day rolling average lb/MMBtu or lb/MWh emissions rates.	Method 19 F-factor methodology at Appendix A–7 to part 60 of this chapter, or calculate using mass emissions rate and electrical output data (see § 63.10007(e)).

[1] Regarding emissions data collected during periods of startup or shutdown, see §§ 63.10020(b) and (c) and § 63.10021(h).

[2] See Tables 1 and 2 to this subpart for required sample volumes and/or sampling run times.

[3] Incorporated by reference, see § 63.14.

[4] When using ASTM D6348–03, the following conditions must be met: (1) The test plan preparation and implementation in the Annexes to ASTM D6348–03, Sections A1 through A8 are mandatory; (2) For ASTM D6348–03 Annex A5 (Analyte Spiking Technique), the percent (%) R must be determined for each target analyte (see Equation A5.5); (3) For the ASTM D6348–03 test data to be acceptable for a target analyte, %R must be 70% ≥ R ≤ 130%; and (4) The %R value for each compound must be reported in the test report and all field measurements corrected with the calculated %R value for that compound using the following equation:

$$Reported\ Result = \frac{(Measured\ Concentration\ in\ Stack)}{\%R} \times 100$$

TABLE 6 TO SUBPART UUUUU OF PART 63—ESTABLISHING PM CPMS OPERATING LIMITS

[As stated in § 63.10007, you must comply with the following requirements for establishing operating limits]

If you have an applicable emission limit for . . .	And you choose to establish PM CPMS operating limits, you must . . .	And . . .	Using . . .	According to the following procedures . . .
Particulate matter (PM), total non-mercury HAP metals, individual non-mercury HAP metals, total HAP metals, individual HAP metals.	Install, certify, maintain, and operate a PM CPMS for monitoring emissions discharged to the atmosphere according to § 63.10010(g)(1).	Establish a site-specific operating limit in units of PM CPMS output signal (*e.g.,* milliamps, mg/acm, or other raw signal).	Data from the PM CPMS and the PM or HAP metals performance tests.	1. Collect PM CPMS output data during the entire period of the performance tests. 2. Record the average hourly PM CPMS output for each test run in the three run performance test. 3. Determine the highest 1-hour average PM CPMS measured during the performance test demonstrating compliance with the filterable PM or HAP metals emissions limitations.

TABLE 7 TO SUBPART UUUUU OF PART 63—DEMONSTRATING CONTINUOUS COMPLIANCE

[As stated in § 63.10021, you must show continuous compliance with the emission limitations for affected sources according to the following]

If you use one of the following to meet applicable emissions limits, operating limits, or work practice standards . . .	You demonstrate continuous compliance by . . .
1. CEMS to measure filterable PM, SO2, HCl, HF, or Hg emissions, or using a sorbent trap monitoring system to measure Hg.	Calculating the 30-boiler operating day rolling arithmetic average emissions rate in units of the applicable emissions standard basis at the end of each boiler operating day using all of the quality assured hourly average CEMS or sorbent trap data for the previous 30 boiler operating days, excluding data recorded during periods of startup or shutdown.
2. PM CPMS to measure compliance with a parametric operating limit	Calculating the arithmetic 30-boiler operating day rolling average of all of the quality assured hourly average PM CPMS output data (*e.g.,* milliamps, PM concentration, raw data signal) collected for all operating hours for the previous 30 boiler operating days, excluding data recorded during periods of startup or shutdown.
3. Site-specific monitoring for liquid oil-fired units for HCl and HF emission limit monitoring.	If applicable, by conducting the monitoring in accordance with an approved site-specific monitoring plan.
4. Quarterly performance testing for coal-fired, solid oil derived fired, or liquid oil-fired units to measure compliance with one or more applicable emissions limit in Table 1 or 2.	Calculating the results of the testing in units of the applicable emissions standard.
5. Conducting periodic performance tune-ups of your EGU(s)	Conducting periodic performance tune-ups of your EGU(s), as specified in § 63.10021(e).
6. Work practice standards for coal-fired, liquid oil-fired, or solid oil-derived fuel-fired EGUs during startup.	Operating in accordance with Table 3.
7. Work practice standards for coal-fired, liquid oil-fired, or solid oil-derived fuel-fired EGUs during shutdown.	Operating in accordance with Table 3.

TABLE 8 TO SUBPART UUUUU OF PART 63—REPORTING REQUIREMENTS

[As stated in § 63.10031, you must comply with the following requirements for reports]

You must submit a . . .	The report must contain . . .	You must submit the report . . .
1. Compliance report	a. Information required in § 63.10031(c)(1) through (4); and b. If there are no deviations from any emission limitation (emission limit and operating limit) that applies to you and there are no deviations from the requirements for work practice standards in Table 3 to this subpart that apply to you, a statement that there were no deviations from the emission limitations and work practice standards during the reporting period. If there were no periods during which the CMSs, including continuous emissions monitoring system, and operating parameter monitoring systems, were out-of-control as specified in § 63.8(c)(7), a statement that there were no periods during which the CMSs were out-of-control during the reporting period; and c. If you have a deviation from any emission limitation (emission limit and operating limit) or work practice standard during the reporting period, the report must contain the information in § 63.10031(d). If there were periods during which the CMSs, including continuous emissions monitoring systems and continuous parameter monitoring systems, were out-of-control, as specified in § 63.8(c)(7), the report must contain the information in § 63.10031(e).	Semiannually according to the requirements in § 63.10031(b).

TABLE 9 TO SUBPART UUUUU OF PART 63—APPLICABILITY OF GENERAL PROVISIONS TO SUBPART UUUUU

[As stated in § 63.10040, you must comply with the applicable General Provisions according to the following]

Citation	Subject	Applies to subpart UUUUU
§ 63.1	Applicability	Yes.
§ 63.2	Definitions	Yes. Additional terms defined in § 63.10042.
§ 63.3	Units and Abbreviations	Yes.
§ 63.4	Prohibited Activities and Circumvention	Yes.
§ 63.5	Preconstruction Review and Notification Requirements.	Yes.
§ 63.6(a), (b)(1)–(b)(5), (b)(7), (c), (f)(2)–(3), (g), (h)(2)–(h)(9), (i), (j).	Compliance with Standards and Maintenance Requirements.	Yes.
§ 63.6(e)(1)(i)	General Duty to minimize emissions	No. See § 63.10000(b) for general duty requirement.
§ 63.6(e)(1)(ii)	Requirement to correct malfunctions ASAP	No.
§ 63.6(e)(3)	SSM Plan requirements	No.
§ 63.6(f)(1)	SSM exemption	No.
§ 63.6(h)(1)	SSM exemption	No.
§ 63.7(a), (b), (c), (d), (e)(2)–(e)(9), (f), (g), and (h).	Performance Testing Requirements	Yes.
§ 63.7(e)(1)	Performance testing	No. See § 63.10007.
§ 63.8	Monitoring Requirements	Yes.
63.8(c)(1)(i)	General duty to minimize emissions and CMS operation.	No. See § 63.10000(b) for general duty requirement.
§ 63.8(c)(1)(iii)	Requirement to develop SSM Plan for CMS	No.
§ 63.8(d)(3)	Written procedures for CMS	Yes, except for last sentence, which refers to an SSM plan. SSM plans are not required.
§ 63.9	Notification Requirements	Yes.
§ 63.10(a), (b)(1), (c), (d)(1)–(2), (e), and (f)	Recordkeeping and Reporting Requirements	Yes, except for the requirements to submit written reports under § 63.10(e)(3)(v).
§ 63.10(b)(2)(i)	Recordkeeping of occurrence and duration of startups and shutdowns.	No.
§ 63.10(b)(2)(ii)	Recordkeeping of malfunctions	No. See 63.10001 for recordkeeping of (1) occurrence and duration and (2) actions taken during malfunction.
§ 63.10(b)(2)(iii)	Maintenance records	Yes.
§ 63.10(b)(2)(iv)	Actions taken to minimize emissions during SSM.	No.
§ 63.10(b)(2)(v)	Actions taken to minimize emissions during SSM.	No.
§ 63.10(b)(2)(vi)	Recordkeeping for CMS malfunctions	Yes.
§ 63.10(b)(2)(vii)–(ix)	Other CMS requirements	Yes.
§ 63.10(b)(3), and (d)(3)–(5)		No.
§ 63.10(c)(7)	Additional recordkeeping requirements for CMS—identifying exceedances and excess emissions.	Yes.
§ 63.10(c)(8)	Additional recordkeeping requirements for CMS—identifying exceedances and excess emissions.	Yes.
§ 63.10(c)(10)	Recording nature and cause of malfunctions	No. See 63.10032(g) and (h) for malfunctions recordkeeping requirements.

TABLE 9 TO SUBPART UUUUU OF PART 63—APPLICABILITY OF GENERAL PROVISIONS TO SUBPART UUUUU—Continued

[As stated in § 63.10040, you must comply with the applicable General Provisions according to the following]

Citation	Subject	Applies to subpart UUUUU
§ 63.10(c)(11)	Recording corrective actions	No. See 63.10032(g) and (h) for malfunctions recordkeeping requirements.
§ 63.10(c)(15)	Use of SSM Plan	No.
§ 63.10(d)(5)	SSM reports	No. See 63.10021(h) and (i) for malfunction reporting requirements.
§ 63.11	Control Device Requirements	No.
§ 63.12	State Authority and Delegation	Yes.
§ 63.13–63.16	Addresses, Incorporation by Reference, Availability of Information, Performance Track Provisions.	Yes.
§ 63.1(a)(5), (a)(7)–(a)(9), (b)(2), (c)(3)–(4), (d), 63.6(b)(6), (c)(3), (c)(4), (d), (e)(2), (e)(3)(ii), (h)(3), (h)(5)(iv), 63.8(a)(3), 63.9(b)(3), (h)(4), 63.10(c)(2)–(4), (c)(9).	Reserved	No.

Appendix A to Subpart UUUUU—Hg Monitoring Provisions

1. General Provisions

1.1 *Applicability.* These monitoring provisions apply to the measurement of total vapor phase mercury (Hg) in emissions from electric utility steam generating units, using either a mercury continuous emission monitoring system (Hg CEMS) or a sorbent trap monitoring system. The Hg CEMS or sorbent trap monitoring system must be capable of measuring the total vapor phase mercury in units of the applicable emissions standard (*e.g.,* lb/TBtu or lb/GWh), regardless of speciation.

1.2 *Initial Certification and Recertification Procedures.* The owner or operator of an affected unit that uses a Hg CEMS or a sorbent trap monitoring system together with other necessary monitoring components to account for Hg emissions in units of the applicable emissions standard shall comply with the initial certification and recertification procedures in section 4 of this appendix.

1.3 *Quality Assurance and Quality Control Requirements.* The owner or operator of an affected unit that uses a Hg CEMS or a sorbent trap monitoring system together with other necessary monitoring components to account for Hg emissions in units of the applicable emissions standard shall meet the applicable quality assurance requirements in section 5 of this appendix.

1.4 *Missing Data Procedures.* The owner or operator of an affected unit is not required to substitute for missing data from Hg CEMS or sorbent trap monitoring systems. Any process operating hour for which quality-assured Hg concentration data are not obtained is counted as an hour of monitoring system downtime.

2. Monitoring of Hg Emissions

2.1 *Monitoring System Installation Requirements.* Flue gases from the affected units under this subpart vent to the atmosphere through a variety of exhaust configurations including single stacks, common stack configurations, and multiple stack configurations. For each of these configurations, § 63.10010(a) specifies the appropriate location(s) at which to install continuous monitoring systems (CMS). These CMS installation provisions apply to the Hg CEMS, sorbent trap monitoring systems, and other continuous monitoring systems that provide data for the Hg emissions calculations in section 6.2 of this appendix.

2.2 *Primary and Backup Monitoring Systems.* In the electronic monitoring plan described in section 7.1.1.2.1 of this appendix, you must designate a primary Hg CEMS or sorbent trap monitoring system. The primary system must be used to report hourly Hg concentration values when the system is able to provide quality-assured data, *i.e.,* when the system is "in control". However, to increase data availability in the event of a primary monitoring system outage, you may install, operate, maintain, and calibrate backup monitoring systems, as follows:

2.2.1 *Redundant Backup Systems.* A redundant backup monitoring system may be either a separate Hg CEMS with its own probe, sample interface, and analyzer, or a separate sorbent trap monitoring system. A redundant backup system is one that is permanently installed at the unit or stack location, and is kept on "hot standby" in case the primary monitoring system is unable to provide quality-assured data. A redundant backup system must be represented as a unique monitoring system in the electronic monitoring plan. Each redundant backup monitoring system must be certified according to the applicable provisions in section 4 of this appendix and must meet the applicable on-going QA requirements in section 5 of this appendix.

2.2.2 *Non-redundant Backup Monitoring Systems.* A non-redundant backup monitoring system is a separate Hg CEMS or sorbent trap system that has been certified at a particular unit or stack location, but is not permanently installed at that location. Rather, the system is kept on "cold standby" and may be reinstalled in the event of a primary monitoring system outage. A non-redundant backup monitoring system must be represented as a unique monitoring system in the electronic monitoring plan. Non-redundant backup Hg CEMS must complete the same certification tests as the primary monitoring system, with one exception. The 7-day calibration error test is not required for a non-redundant backup Hg CEMS. Except as otherwise provided in section 2.2.4.5 of this appendix, a non-redundant backup monitoring system may only be used for 720 hours per year at a particular unit or stack location.

2.2.3 *Temporary Like-kind Replacement Analyzers.* When a primary Hg analyzer needs repair or maintenance, you may temporarily install a like-kind replacement analyzer, to minimize data loss. Except as otherwise provided in section 2.2.4.5 of this appendix, a temporary like-kind replacement analyzer may only be used for 720 hours per year at a particular unit or stack location. The analyzer must be represented as a component of the primary Hg CEMS, and must be assigned a 3-character component ID number, beginning with the prefix "LK".

2.2.4 *Quality Assurance Requirements for Non-redundant Backup Monitoring Systems and Temporary Like-kind Replacement Analyzers.* To quality-assure the data from non-redundant backup Hg monitoring systems and temporary like-kind replacement Hg analyzers, the following provisions apply:

2.2.4.1 When a certified non-redundant backup sorbent trap monitoring system is brought into service, you must follow the procedures for routine day-to-day operation of the system, in accordance with Performance Specification (PS) 12B in appendix B to part 60 of this chapter.

2.2.4.2 When a certified non-redundant backup Hg CEMS or a temporary like-kind replacement Hg analyzer is brought into service, a calibration error test and a linearity check must be performed and passed. A single point system integrity check is also required, unless a NIST-traceable source of oxidized Hg was used for the calibration error test.

2.2.4.3 Each non-redundant backup Hg CEMS or temporary like-kind replacement Hg analyzer shall comply with all required daily, weekly, and quarterly quality-assurance test requirements in section 5 of this appendix, for as long as the system or analyzer remains in service.

2.2.4.4 For the routine, on-going quality-assurance of a non-redundant backup Hg monitoring system, a relative accuracy test audit (RATA) must be performed and passed at least once every 8 calendar quarters at the

unit or stack location(s) where the system will be used.

2.2.4.5 To use a non-redundant backup Hg monitoring system or a temporary like-kind replacement analyzer for more than 720 hours per year at a particular unit or stack location, a RATA must first be performed and passed at that location.

3. Mercury Emissions Measurement Methods

The following definitions, equipment specifications, procedures, and performance criteria are applicable to the measurement of vapor-phase Hg emissions from electric utility steam generating units, under relatively low-dust conditions (i.e., sampling in the stack or duct after all pollution control devices). The analyte measured by these procedures and specifications is total vapor-phase Hg in the flue gas, which represents the sum of elemental Hg (Hg^0, CAS Number 7439–97–6) and oxidized forms of Hg.

3.1 *Definitions.*

3.1.1 *Mercury Continuous Emission Monitoring System or Hg CEMS* means all of the equipment used to continuously determine the total vapor phase Hg concentration. The measurement system may include the following major subsystems: sample acquisition, Hg^{+2} to Hg^0 converter, sample transport, sample conditioning, flow control/gas manifold, gas analyzer, and data acquisition and handling system (DAHS). Hg CEMS may be nominally real-time or time-integrated, batch sampling systems that sample the gas on an intermittent basis and concentrate on a collection medium before intermittent analysis and reporting.

3.1.2 *Sorbent Trap Monitoring System* means the equipment required to monitor Hg emissions continuously by using paired sorbent traps containing iodated charcoal (IC) or other suitable sorbent medium. The monitoring system consists of a probe, paired sorbent traps, an umbilical line, moisture removal components, an airtight sample pump, a gas flow meter, and an automated data acquisition and handling system. The system samples the stack gas at a constant proportional rate relative to the stack gas volumetric flow rate. The sampling is a batch process. The average Hg concentration in the stack gas for the sampling period is determined, in units of micrograms per dry standard cubic meter (μg/dscm), based on the sample volume measured by the gas flow meter and the mass of Hg collected in the sorbent traps.

3.1.3 *NIST* means the National Institute of Standards and Technology, located in Gaithersburg, Maryland.

3.1.4 *NIST–Traceable Elemental Hg Standards* means either: compressed gas cylinders having known concentrations of elemental Hg, which have been prepared according to the "EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards"; or calibration gases having known concentrations of elemental Hg, produced by a generator that meets the performance requirements of the "EPA Traceability Protocol for Qualification and Certification of Elemental Mercury Gas Generators" or an interim version of that protocol.

3.1.5 *NIST–Traceable Source of Oxidized Hg* means a generator that is capable of providing known concentrations of vapor phase mercuric chloride ($HgCl_2$), and that meets the performance requirements of the "EPA Traceability Protocol for Qualification and Certification of Mercuric Chloride Gas Generators" or an interim version of that protocol.

3.1.6 *Calibration Gas* means a NIST-traceable gas standard containing a known concentration of elemental or oxidized Hg that is produced and certified in accordance with an EPA traceability protocol.

3.1.7 *Span Value* means a conservatively high estimate of the Hg concentrations to be measured by a CEMS. The span value of a Hg CEMS should be set to approximately twice the concentration corresponding to the emission standard, rounded off as appropriate (see section 3.2.1.4.2 of this appendix).

3.1.8 *Zero-Level Gas* means calibration gas containing a Hg concentration that is below the level detectable by the Hg gas analyzer in use.

3.1.9 *Low-Level Gas* means calibration gas with a concentration that is 20 to 30 percent of the span value.

3.1.10 *Mid-Level Gas* means calibration gas with a concentration that is 50 to 60 percent of the span value.

3.1.11 *High-Level Gas* means calibration gas with a concentration that is 80 to 100 percent of the span value.

3.1.12 *Calibration Error Test* means a test designed to assess the ability of a Hg CEMS to measure the concentrations of calibration gases accurately. A zero-level gas and an upscale gas are required for this test. For the upscale gas, either a mid-level gas or a high-level gas may be used, and the gas may either be an elemental or oxidized Hg standard.

3.1.13 *Linearity Check* means a test designed to determine whether the response of a Hg analyzer is linear across its measurement range. Three elemental Hg calibration gas standards (i.e., low, mid, and high-level gases) are required for this test.

3.1.14 *System Integrity Check* means a test designed to assess the transport and measurement of oxidized Hg by a Hg CEMS. Oxidized Hg standards are used for this test. For a three-level system integrity check, low, mid, and high-level calibration gases are required. For a single-level check, either a mid-level gas or a high-level gas may be used.

3.1.15 *Cycle Time Test* means a test designed to measure the amount of time it takes for a Hg CEMS, while operating normally, to respond to a known step change in gas concentration. For this test, a zero gas and a high-level gas are required. The high-level gas may be either an elemental or an oxidized Hg standard.

3.1.16 *Relative Accuracy Test Audit* or *RATA* means a series of nine or more test runs, directly comparing readings from a Hg CEMS or sorbent trap monitoring system to measurements made with a reference stack test method. The relative accuracy (RA) of the monitoring system is expressed as the absolute mean difference between the monitoring system and reference method measurements plus the absolute value of the 2.5 percent error confidence coefficient, divided by the mean value of the reference method measurements.

3.1.17 *Unit Operating Hour* means a clock hour in which a unit combusts any fuel, either for part of the hour or for the entire hour.

3.1.18 *Stack Operating Hour* means a clock hour in which gases flow through a particular monitored stack or duct (either for part of the hour or for the entire hour), while the associated unit(s) are combusting fuel.

3.1.19 *Operating Day* means a calendar day in which a source combusts any fuel.

3.1.20 Quality Assurance *(QA) Operating Quarter* means a calendar quarter in which there are at least 168 unit or stack operating hours (as defined in this section).

3.1.21 *Grace Period* means a specified number of unit or stack operating hours after the deadline for a required quality-assurance test of a continuous monitor has passed, in which the test may be performed and passed without loss of data.

3.2 *Continuous Monitoring Methods.*

3.2.1 *Hg CEMS.* A typical Hg CEMS is shown in Figure A–1. The CEMS in Figure A–1 is a dilution extractive system, which measures Hg concentration on a wet basis, and is the most commonly-used type of Hg CEMS. Other system designs may be used, provided that the CEMS meets the performance specifications in section 4.1.1 of this appendix.

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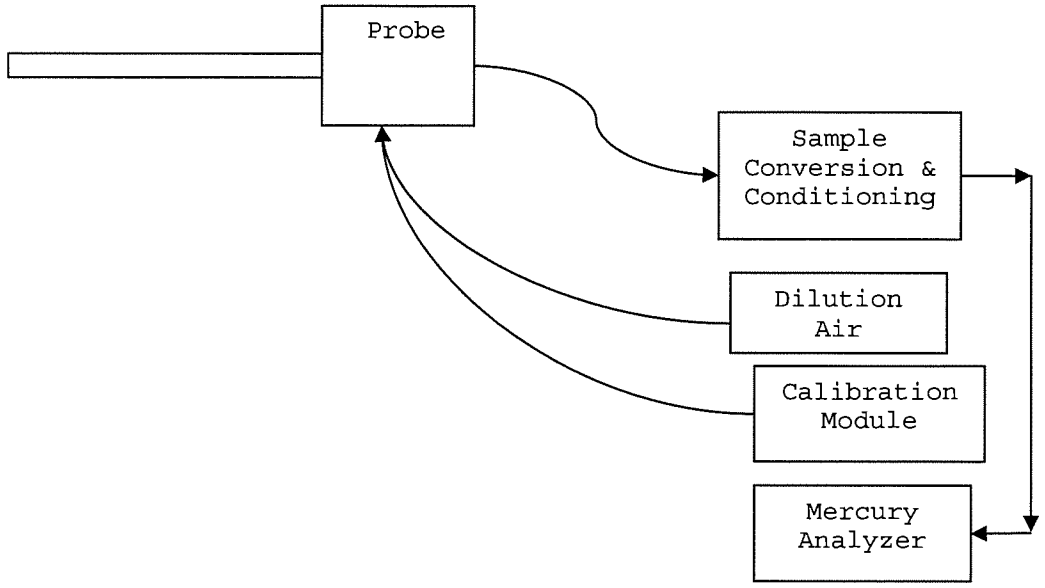

FIGURE A-1. TYPICAL MERCURY CEMS

3.2.1.1 *Equipment Specifications.*

3.2.1.1.1 *Materials of Construction.* All wetted sampling system components, including probe components prior to the point at which the calibration gas is introduced, must be chemically inert to all Hg species. Materials such as perfluoroalkoxy (PFA) Teflon™, quartz, and treated stainless steel (SS) are examples of such materials.

3.2.1.1.2 *Temperature Considerations.* All system components prior to the Hg^{+2} to Hg^0 converter must be maintained at a sample temperature above the acid gas dew point.

3.2.1.1.3 *Measurement System Components.*

3.2.1.1.3.1 *Sample Probe.* The probe must be made of the appropriate materials as noted in paragraph 3.2.1.1.1 of this section, heated when necessary, as described in paragraph 3.2.1.1.3.4 of this section, and configured with ports for introduction of calibration gases.

3.2.1.1.3.2 *Filter or Other Particulate Removal Device.* The filter or other particulate removal device is part of the measurement system, must be made of appropriate materials, as noted in paragraph 3.2.1.1.1 of this section, and must be included in all system tests.

3.2.1.1.3.3 *Sample Line.* The sample line that connects the probe to the converter, conditioning system, and analyzer must be made of appropriate materials, as noted in paragraph 3.2.1.1.1 of this section.

3.2.1.1.3.4 *Conditioning Equipment.* For wet basis systems, such as the one shown in Figure A–1, the sample must be kept above its dew point either by: heating the sample line and all sample transport components up to the inlet of the analyzer (and, for hot-wet extractive systems, also heating the analyzer); or diluting the sample prior to analysis using a dilution probe system. The components required for these operations are considered to be conditioning equipment. For dry basis measurements, a condenser, dryer or other suitable device is required to remove moisture continuously from the sample gas, and any equipment needed to heat the probe or sample line to avoid condensation prior to the moisture removal component is also required.

3.2.1.1.3.5 *Sampling Pump.* A pump is needed to push or pull the sample gas through the system at a flow rate sufficient to minimize the response time of the measurement system. If a mechanical sample pump is used and its surfaces are in contact with the sample gas prior to detection, the pump must be leak free and must be constructed of a material that is non-reactive to the gas being sampled (see paragraph 3.2.1.1.1 of this section). For dilution-type measurement systems, such as the system shown in Figure A–1, an ejector pump (eductor) may be used to create a sufficient vacuum that sample gas will be drawn through a critical orifice at a constant rate. The ejector pump must be constructed of any material that is non-reactive to the gas being sampled.

3.2.1.1.3.6 *Calibration Gas System(s).* Design and equip each Hg CEMS to permit the introduction of known concentrations of elemental Hg and $HgCl_2$ separately, at a point preceding the sample extraction filtration system, such that the entire measurement system can be checked. The calibration gas system(s) must be designed so that the flow rate exceeds the sampling system flow requirements and that the gas is delivered to the CEMS at atmospheric pressure.

3.2.1.1.3.7 *Sample Gas Delivery.* The sample line may feed directly to either a converter, a by-pass valve (for Hg speciating systems), or a sample manifold. All valve and/or manifold components must be made of material that is non-reactive to the gas sampled and the calibration gas, and must be configured to safely discharge any excess gas.

3.2.1.1.3.8 *Hg Analyzer.* An instrument is required that continuously measures the total vapor phase Hg concentration in the gas stream. The analyzer may also be capable of measuring elemental and oxidized Hg separately.

3.2.1.1.3.9 *Data Recorder.* A recorder, such as a computerized data acquisition and handling system (DAHS), digital recorder, or data logger, is required for recording measurement data.

3.2.1.2 *Reagents and Standards.*

3.2.1.2.1 *NIST Traceability.* Only NIST-certified or NIST-traceable calibration gas standards and reagents (as defined in paragraphs 3.1.4 and 3.1.5 of this section) shall be used for the tests and procedures required under this subpart. Calibration gases with known concentrations of Hg^0 and $HgCl_2$ are required. Special reagents and equipment may be needed to prepare the Hg^0 and $HgCl_2$ gas standards (*e.g.,* NIST-traceable solutions of $HgCl_2$ and gas generators equipped with mass flow controllers).

3.2.1.2.2 *Required Calibration Gas Concentrations.*

3.2.1.2.2.1 *Zero-Level Gas.* A zero-level calibration gas with a Hg concentration below the level detectable by the Hg analyzer is required for calibration error tests and cycle time tests of the CEMS.

3.2.1.2.2.2 *Low-Level Gas.* A low-level calibration gas with a Hg concentration of 20 to 30 percent of the span value is required for linearity checks and 3-level system integrity checks of the CEMS. Elemental Hg standards are required for the linearity checks and oxidized Hg standards are required for the system integrity checks.

3.2.1.2.2.3 *Mid-Level Gas.* A mid-level calibration gas with a Hg concentration of 50

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to 60 percent of the span value is required for linearity checks and for 3-level system integrity checks of the CEMS, and is optional for calibration error tests and single-level system integrity checks. Elemental Hg standards are required for the linearity checks, oxidized Hg standards are required for the system integrity checks, and either elemental or oxidized Hg standards may be used for the calibration error tests.

3.2.1.2.2.4 *High-Level Gas.* A high-level calibration gas with a Hg concentration of 80 to 100 percent of the span value is required for linearity checks, 3-level system integrity checks, and cycle time tests of the CEMS, and is optional for calibration error tests and single-level system integrity checks. Elemental Hg standards are required for the linearity checks, oxidized Hg standards are required for the system integrity checks, and either elemental or oxidized Hg standards may be used for the calibration error and cycle time tests.

3.2.1.3 *Installation and Measurement Location.* For the Hg CEMS and any additional monitoring system(s) needed to convert Hg concentrations to the desired units of measure (i.e., a flow monitor, CO_2 or O_2 monitor, and/or moisture monitor, as applicable), install each monitoring system at a location: that is consistent with 63.10010(a); that represents the emissions exiting to the atmosphere; and where it is likely that the CEMS can pass the relative accuracy test.

3.2.1.4 *Monitor Span and Range Requirements.* Determine the appropriate span and range value(s) for the Hg CEMS as described in paragraphs 3.2.1.4.1 through 3.2.1.4.3 of this section.

3.2.1.4.1 *Maximum Potential Concentration.* There are three options for determining the maximum potential Hg concentration (MPC). Option 1 applies to coal combustion. You may use a default value of 10 μg/scm for all coal ranks (including coal refuse) except for lignite; for lignite, use 16 μg/scm. If different coals are blended as part of normal operation, use the highest MPC for any fuel in the blend. Option 2 is to base the MPC on the results of site-specific Hg emission testing. This option may be used only if the unit does not have add-on Hg emission controls or a flue gas desulfurization system, or if testing is performed upstream of all emission control devices. If Option 2 is selected, perform at least three test runs at the normal operating load, and the highest Hg concentration obtained in any of the tests shall be the MPC. Option 3 is to use fuel sampling and analysis to estimate the MPC. To make this estimate, use the average Hg content (*i.e.,* the weight percentage) from at least three representative fuel samples, together with other available information, including, but not limited to the maximum fuel feed rate, the heating value of the fuel, and an appropriate F-factor. Assume that all of the Hg in the fuel is emitted to the atmosphere as vapor-phase Hg.

3.2.1.4.2 *Span Value.* To determine the span value of the Hg CEMS, multiply the Hg concentration corresponding to the applicable emissions standard by two. If the result of this calculation is an exact multiple of 10 μg/scm, use the result as the span value. Otherwise, round off the result to either: the next highest integer; the next highest multiple of 5 μg/scm; or the next highest multiple of 10 μg/scm.

3.2.1.4.3 *Analyzer Range.* The Hg analyzer must be capable of reading Hg concentration as high as the MPC.

3.2.2 *Sorbent Trap Monitoring System.* A sorbent trap monitoring system (as defined in paragraph 3.1.2 of this section) may be used as an alternative to a Hg CEMS. If this option is selected, the monitoring system shall be installed, maintained, and operated in accordance with Performance Specification (PS) 12B in Appendix B to part 60 of this chapter. The system shall be certified in accordance with the provisions of section 4.1.2 of this appendix.

3.2.3 *Other Necessary Data Collection.* To convert measured hourly Hg concentrations to the units of the applicable emissions standard (*i.e.,* lb/TBtu or lb/GWh), additional data must be collected, as described in paragraphs 3.2.3.1 through 3.2.3.3 of this section. Any additional monitoring systems needed for this purpose must be certified, operated, maintained, and quality-assured according to the applicable provisions of part 75 of this chapter (see §§ 63.10010(b) through (d)). The calculation methods for the types of emission limits described in paragraphs 3.2.3.1 and 3.2.3.2 of this section are presented in section 6.2 of this appendix.

3.2.3.1 *Heat Input-Based Emission Limits.* For a heat input-based Hg emission limit (*i.e.,* in lb/TBtu), data from a certified CO_2 or O_2 monitor are needed, along with a fuel-specific F-factor and a conversion constant to convert measured Hg concentration values to the units of the standard. In some cases, the stack gas moisture content must also be considered in making these conversions.

3.2.3.2 *Electrical Output-Based Emission Rates.* If the applicable Hg limit is electrical output-based (*i.e.,* lb/GWh), hourly electrical load data and unit operating times are required in addition to hourly data from a certified stack gas flow rate monitor and (if applicable) moisture data.

3.2.3.3 *Sorbent Trap Monitoring System Operation.* Routine operation of a sorbent trap monitoring system requires the use of a certified stack gas flow rate monitor, to maintain an established ratio of stack gas flow rate to sample flow rate.

4. Certification and Recertification Requirements

4.1 *Certification Requirements.* All Hg CEMS and sorbent trap monitoring systems and the additional monitoring systems used to continuously measure Hg emissions in units of the applicable emissions standard in accordance with this appendix must be certified in a timely manner, such that the initial compliance demonstration is completed no later than the applicable date in § 63.10005(g).

4.1.1 *Hg CEMS.* Table A–1, below, summarizes the certification test requirements and performance specifications for a Hg CEMS. The CEMS may not be used to report quality-assured data until these performance criteria are met. Paragraphs 4.1.1.1 through 4.1.1.5 of this section provide specific instructions for the required tests. All tests must be performed with the affected unit(s) operating (*i.e.,* combusting fuel). Except for the RATA, which must be performed at normal load, no particular load level is required for the certification tests.

4.1.1.1 *7-Day Calibration Error Test.* Perform the 7-day calibration error test on 7 consecutive source operating days, using a zero-level gas and either a high-level or a mid-level calibration gas standard (as defined in sections 3.1.8, 3.1.10, and 3.1.11 of this appendix). Either elemental or oxidized NIST-traceable Hg standards (as defined in sections 3.1.4 and 3.1.5 of this appendix) may be used for the test. If moisture and/or chlorine is added to the calibration gas, the dilution effect of the moisture and/or chlorine addition on the calibration gas concentration must be accounted for in an appropriate manner. Operate the Hg CEMS in its normal sampling mode during the test. The calibrations should be approximately 24 hours apart, unless the 7-day test is performed over nonconsecutive calendar days. On each day of the test, inject the zero-level and upscale gases in sequence and record the analyzer responses. Pass the calibration gas through all filters, scrubbers, conditioners, and other monitor components used during normal sampling, and through as much of the sampling probe as is practical. Do not make any manual adjustments to the monitor (*i.e.,* resetting the calibration) until after taking measurements at both the zero and upscale concentration levels. If automatic adjustments are made following both injections, conduct the calibration error test such that the magnitude of the adjustments can be determined, and use only the unadjusted analyzer responses in the calculations. Calculate the calibration error (CE) on each day of the test, as described in Table A–1. The CE on each day of the test must either meet the main performance specification or the alternative specification in Table A–1.

4.1.1.2 *Linearity Check.* Perform the linearity check using low, mid, and high-level concentrations of NIST-traceable elemental Hg standards. Three gas injections at each concentration level are required, with no two successive injections at the same concentration level. Introduce the calibration gas at the gas injection port, as specified in section 3.2.1.1.3.6 of this appendix. Operate the CEMS at its normal operating temperature and conditions. Pass the calibration gas through all filters, scrubbers, conditioners, and other components used during normal sampling, and through as much of the sampling probe as is practical. If moisture and/or chlorine is added to the calibration gas, the dilution effect of the moisture and/or chlorine addition on the calibration gas concentration must be accounted for in an appropriate manner. Record the monitor response from the data acquisition and handling system for each gas injection. At each concentration level, use the average analyzer response to calculate the linearity error (LE), as described in Table A–1. The LE must either meet the main performance specification or the alternative specification in Table A–1.

4.1.1.3 *Three-Level System Integrity Check.* Perform the 3-level system integrity

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check using low, mid, and high-level calibration gas concentrations generated by a NIST-traceable source of oxidized Hg. Follow the same basic procedure as for the linearity check. If moisture and/or chlorine is added to the calibration gas, the dilution effect of the moisture and/or chlorine addition on the calibration gas concentration must be accounted for in an appropriate manner. Calculate the system integrity error (SIE), as described in Table A–1. The SIE must either meet the main performance specification or the alternative specification in Table A–1. (**Note:** This test is not required if the CEMS does not have a converter).

TABLE A–1—REQUIRED CERTIFICATION TESTS AND PERFORMANCE SPECIFICATIONS FOR Hg CEMS

For this required certification test . . .	The main performance specification[1] is . . .	The alternate performance specification[1] is . . .	And the conditions of the alternate specification are . . .
7-day calibration error test[2]	$\|R - A\|$ ≤5.0% of span value, for both the zero and upscale gases, on each of the 7 days.	$\|R - A\|$ ≤1.0 µg/scm	The alternate specification may be used on any day of the test.
Linearity check[3]	$\|R - A_{avg}\|$ ≤10.0% of the reference gas concentration at each calibration gas level (low, mid, or high).	$\|R - A_{avg}\|$ ≤0.8 µg/scm	The alternate specification may be used at any gas level.
3-level system integrity check[4]	$\|R - A_{avg}\|$ ≤10.0% of the reference gas concentration at each calibration gas level.	$\|R - A_{avg}\|$ ≤0.8 µg/scm	The alternate specification may be used at any gas level.
RATA	20.0% RA	$\|RM_{avg} - C_{avg}\|$ ≤1.0 µg/scm**	RM_{avg} <5.0 µg/scm.
Cycle time test[2]	15 minutes.[5]		

[1] Note that $|R - A|$ is the absolute value of the difference between the reference gas value and the analyzer reading. $|R - A_{avg},|$ is the absolute value of the difference between the reference gas concentration and the average of the analyzer responses, at a particular gas level.
[2] Use either elemental or oxidized Hg standards; a mid-level or high-level upscale gas may be used. This test is not required for Hg CEMS that use integrated batch sampling; however, those monitors must be capable of recording at least one Hg concentration reading every 15 minutes.
[3] Use elemental Hg standards.
[4] Use oxidized Hg standards. Not required if the CEMS does not have a converter.
[5] Stability criteria—Readings change by <2.0% of span *or* by ≤0.5 µg/scm, for 2 minutes.
** Note that $|RM_{avg} - C_{avg}|$ is the absolute difference between the mean reference method value and the mean CEMS value from the RATA. The arithmetic difference between RM_{avg} and C_{avg} can be either + or −.

4.1.1.4 *Cycle Time Test.* Perform the cycle time test, using a zero-level gas and a high-level calibration gas.

Either an elemental or oxidized NIST-traceable Hg standard may be used as the high-level gas. Perform the test in two stages—upscale and downscale. The slower of the upscale and downscale response times is the cycle time for the CEMS. Begin each stage of the test by injecting calibration gas after achieving a stable reading of the stack emissions. The cycle time is the amount of time it takes for the analyzer to register a reading that is 95 percent of the way between the stable stack emissions reading and the final, stable reading of the calibration gas concentration. Use the following criterion to determine when a stable reading of stack emissions or calibration gas has been attained—the reading is stable if it changes by no more than 2.0 percent of the span value or 0.5 µg/scm (whichever is less restrictive) for two minutes, or a reading with a change of less than 6.0 percent from the measured average concentration over 6 minutes. Integrated batch sampling type Hg CEMS are exempted from this test; however, these systems must be capable of delivering a measured Hg concentration reading at least once every 15 minutes. If necessary to increase measurement sensitivity of a batch sampling type Hg CEMS for a specific application, you may petition the Administrator for approval of a time longer than 15 minutes between readings.

4.1.1.5 *Relative Accuracy Test Audit (RATA).* Perform the RATA of the Hg CEMS at normal load. Acceptable Hg reference methods for the RATA include ASTM D6784–02 (Reapproved 2008), "Standard Test Method for Elemental, Oxidized, Particle-Bound and Total Mercury in Flue Gas Generated from Coal-Fired Stationary Sources (Ontario Hydro Method)" (incorporated by reference, see § 63.14) and Methods 29, 30A, and 30B in appendix A–8 to part 60. When Method 29 or ASTM D6784–02 is used, paired sampling trains are required. To validate a Method 29 or ASTM D6784–02 test run, calculate the relative deviation (RD) using Equation A–1 of this section, and assess the results as follows to validate the run. The RD must not exceed 10 percent, when the average Hg concentration is greater than 1.0 µg/dscm. If the average concentration is ≤ 1.0 µg/dscm, the RD must not exceed 20 percent. The RD results are also acceptable if the absolute difference between the two Hg concentrations does not exceed 0.2 µg/dscm. If the RD specification is met, the results of the two samples shall be averaged arithmetically.

$$RD = \frac{|C_a - C_b|}{C_a + C_b} \times 100 \quad \text{(Eq. A-1)}$$

Where:

RD = Relative deviation between the Hg concentrations of samples "a" and "b" (percent)
C_a = Hg concentration of Hg sample "a" (µg/dscm)
C_b = Hg concentration of Hg sample "b" (µg/dscm)

4.1.1.5.1 *Special Considerations.* A minimum of nine valid test runs must be performed, directly comparing the CEMS measurements to the reference method. More than nine test runs may be performed. If this option is chosen, the results from a maximum of three test runs may be rejected so long as the total number of test results used to determine the relative accuracy is greater than or equal to nine; however, all data must be reported including the rejected data. The minimum time per run is 21 minutes if Method 30A is used. If Method 29, Method 30B, or ASTM D6784–02 (Reapproved 2008), "Standard Test Method for Elemental, Oxidized, Particle-Bound and Total Mercury in Flue Gas Generated from Coal-Fired Stationary Sources (Ontario Hydro Method)" (incorporated by reference, see § 63.14) is used, the time per run must be long enough to collect a sufficient mass of Hg to analyze. Complete the RATA within 168 unit operating hours, except when Method 29 or ASTM D6784–02 is used, in which case up to 336 operating hours may be taken to finish the test.

4.1.1.5.2 *Calculation of RATA Results.* Calculate the relative accuracy (RA) of the monitoring system, on a µg/scm basis, as described in section 12 of Performance Specification (PS) 2 in Appendix B to part 60 of this chapter (see Equations 2–3 through 2–6 of PS2). For purposes of calculating the relative accuracy, ensure that the reference method and monitoring system data are on a consistent moisture basis, either wet or dry. The CEMS must either meet the main performance specification or the alternative specification in Table A–1.

4.1.1.5.3 *Bias Adjustment.* Measurement or adjustment of Hg CEMS data for bias is not required.

4.1.2 *Sorbent Trap Monitoring Systems.* For the initial certification of a sorbent trap monitoring system, only a RATA is required.

4.1.2.1 *Reference Methods.* The acceptable reference methods for the RATA of a sorbent trap monitoring system are the same as those listed in paragraph 4.1.1.5 of this section.

4.1.2.2 "The special considerations specified in paragraph 4.1.1.5.1 of this section apply to the RATA of a sorbent trap

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monitoring system. During the RATA, the monitoring system must be operated and quality-assured in accordance with Performance Specification (PS) 12B in Appendix B to part 60 of this chapter with the following exceptions for sorbent trap section 2 breakthrough:

4.1.2.2.1 For stack Hg concentrations >1 μg/dscm, ≤10% of section 1 Hg mass;

4.1.2.2.2 For stack Hg concentrations ≤1 μg/dscm and >0.5 μg/dscm, ≤ 20% of section 1 Hg mass;

4.1.2.2.3 For stack Hg concentrations ≤0.5 μg/dscm and >0.1 μg/dscm, ≤ 50% of section 1 Hg mass; and

4.1.2.2.4 For stack Hg concentrations ≤0.1μg/dscm, no breakthrough criterion assuming all other QA/QC specifications are met.

4.1.2.3 The type of sorbent material used by the traps during the RATA must be the same as for daily operation of the monitoring system; however, the size of the traps used for the RATA may be smaller than the traps used for daily operation of the system.

4.1.2.4 *Calculation of RATA Results.* Calculate the relative accuracy (RA) of the sorbent trap monitoring system, on a μg/scm basis, as described in section 12 of Performance Specification (PS) 2 in appendix B to part 60 of this chapter (see Equations 2–3 through 2–6 of PS2). For purposes of calculating the relative accuracy, ensure that the reference method and monitoring system data are on a consistent moisture basis, either wet or dry.The main and alternative RATA performance specifications in Table A–1 for Hg CEMS also apply to the sorbent trap monitoring system.

4.1.2.5 *Bias Adjustment.* Measurement or adjustment of sorbent trap monitoring system data for bias is not required.

4.1.3 *Diluent Gas, Flow Rate, and/or Moisture Monitoring Systems.* Monitoring systems that are used to measure stack gas volumetric flow rate, diluent gas concentration, or stack gas moisture content, either for routine operation of a sorbent trap monitoring system or to convert Hg concentration data to units of the applicable emission limit, must be certified in accordance with the applicable provisions of part 75 of this chapter.

4.2 *Recertification.* Whenever the owner or operator makes a replacement, modification, or change to a certified CEMS or sorbent trap monitoring system that may significantly affect the ability of the system to accurately measure or record pollutant or diluent gas concentrations, stack gas flow rates, or stack gas moisture content, the owner or operator shall recertify the monitoring system. Furthermore, whenever the owner or operator makes a replacement, modification, or change to the flue gas handling system or the unit operation that may significantly change the concentration or flow profile, the owner or operator shall recertify the monitoring system. The same tests performed for the initial certification of the monitoring system shall be repeated for recertification, unless otherwise specified by the Administrator. Examples of changes that require recertification include: replacement of a gas analyzer; complete monitoring system replacement, and changing the location or orientation of the sampling probe.

5. Ongoing Quality Assurance (QA) and Data Validation

5.1 *Hg CEMS.*

5.1.1 *Required QA Tests.* Periodic QA testing of each Hg CEMS is required following initial certification. The required QA tests, the test frequencies, and the performance specifications that must be met are summarized in Table A–2, below. All tests must be performed with the affected unit(s) operating (*i.e.,* combusting fuel). Except for the RATA, which must be performed at normal load, no particular load level is required for the tests. For each test, follow the same basic procedures in section 4.1.1 of this appendix that were used for initial certification.

5.1.2 *Test Frequency.* The frequency for the required QA tests of the Hg CEMS shall be as follows:

5.1.2.1 Calibration error tests of the Hg CEMS are required daily, except during unit outages. Use either NIST-traceable elemental Hg standards or NIST-traceable oxidized Hg standards for these calibrations. Both a zero-level gas and either a mid-level or high-level gas are required for these calibrations.

5.1.2.2 Perform a linearity check of the Hg CEMS in each QA operating quarter, using low-level, mid-level, and high-level NIST-traceable elemental Hg standards. For units that operate infrequently, limited exemptions from this test are allowed for "non-QA operating quarters". A maximum of three consecutive exemptions for this reason are permitted, following the quarter of the last test. After the third consecutive exemption, a linearity check must be performed in the next calendar quarter or within a grace period of 168 unit or stack operating hours after the end of that quarter. The test frequency for 3-level system integrity checks (if performed in lieu of linearity checks) is the same as for the linearity checks. Use low-level, mid-level, and high-level NIST-traceable oxidized Hg standards for the system integrity checks.

5.1.2.3 If required, perform a single-level system integrity check weekly, *i.e.,* once every 7 operating days (see the third column in Table A–2).

5.1.2.4 The test frequency for the RATAs of the Hg CEMS shall be annual, *i.e.,* once every four QA operating quarters. For units that operate infrequently, extensions of RATA deadlines are allowed for non-QA operating quarters. Following a RATA, if there is a subsequent non-QA quarter, it extends the deadline for the next test by one calendar quarter. However, there is a limit to these extensions; the deadline may not be extended beyond the end of the eighth calendar quarter after the quarter of the last test. At that point, a RATA must either be performed within the eighth calendar quarter or in a 720 hour unit or stack operating hour grace period following that quarter. When a required annual RATA is done within a grace period, the deadline for the next RATA is three QA operating quarters after the quarter in which the grace period test is performed.

5.1.3 *Grace Periods.*

5.1.3.1 A 168 unit or stack operating hour grace period is available for quarterly linearity checks and 3-level system integrity checks of the Hg CEMS.

5.1.3.2 A 720 unit or stack operating hour grace period is available for RATAs of the Hg CEMS.

5.1.3.3 There is no grace period for weekly system integrity checks. The test must be completed once every 7 operating days.

5.1.4 *Data Validation.* The Hg CEMS is considered to be out-of-control, and data from the CEMS may not be reported as quality-assured, when any one of the acceptance criteria for the required QA tests in Table A–2 is not met. The CEMS is also considered to be out-of-control when a required QA test is not performed on schedule or within an allotted grace period. To end an out-of-control period, the QA test that was either failed or not done on time must be performed and passed. Out-of-control periods are counted as hours of monitoring system downtime.

5.1.5 *Conditional Data Validation.* For certification, recertification, and diagnostic testing of Hg monitoring systems, and for the required QA tests when non-redundant backup Hg monitoring systems or temporary like-kind Hg analyzers are brought into service, the conditional data validation provisions in §§ 75.20(b)(3)(ii) through (b)(3)(ix) of this chapter may be used to avoid or minimize data loss. The allotted window of time to complete 7-day calibration error tests, linearity checks, cycle time tests, and RATAs shall be as specified in § 75.20(b)(3)(iv) of this chapter. Required system integrity checks must be completed within 168 unit or stack operating hours after the probationary calibration error test.

TABLE A–2—ON-GOING QA TEST REQUIREMENTS FOR Hg CEMS

Perform this type of QA test . . .	At this frequency . . .	With these qualifications and exceptions . . .	Acceptance criteria . . .
Calibration error test	Daily	• Use either a mid- or high-level gas. • Use either elemental or oxidized Hg.	|R − A| ≤ 5.0% of span value. *or* |R − A| ≤ 1.0 μg/scm.

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TABLE A–2—ON-GOING QA TEST REQUIREMENTS FOR Hg CEMS—Continued

Perform this type of QA test . . .	At this frequency . . .	With these qualifications and exceptions . . .	Acceptance criteria . . .
Single-level system integrity check	Weekly [1]	• Calibrations are not required when the unit is not in operation. • Required only for systems with converters. • Use oxidized Hg—either mid- or high-level. • Not required if daily calibrations are done with a NIST-traceable source of oxidized Hg.	$\lvert R - A_{avg} \rvert \leq 10.0\%$ of the reference gas value. *or* $\lvert R - A_{avg} \rvert \leq 0.8$ µg/scm.
Linearity check *or* 3-level system integrity check	Quarterly [3]	• Required in each "QA operating quarter" [2]—and no less than once every 4 calendar quarters. • 168 operating hour grace period available. • Use elemental Hg for linearity check. • Use oxidized Hg for system integrity check. • For system integrity check, CEMS must have a converter.	$\lvert R - A_{avg} \rvert \leq 10.0\%$ of the reference gas value, at each calibration gas level. *or* $\lvert R - A_{avg} \rvert \leq 0.8$ µg/scm.
RATA	Annual [4]	• Test deadline may be extended for "non-QA operating quarters", up to a maximum of 8 quarters from the quarter of the previous test. • 720 operating hour grace period available.	20.0% RA. *or* $\lvert RM_{avg} - C_{avg} \rvert \leq 1.0$ µg/scm, *if* $RM_{avg} < 5.0$ µg/scm.

[1] "Weekly" means once every 7 operating days.
[2] A "QA operating quarter" is a calendar quarter with at least 168 unit or stack operating hours.
[3] "Quarterly" means once every QA operating quarter.
[4] "Annual" means once every four QA operating quarters.

5.1.6 *Adjustment of Span.* If you discover that a span adjustment is needed (*e.g.,* if the Hg concentration readings exceed the span value for a significant percentage of the unit operating hours in a calendar quarter), you must implement the span adjustment within 90 days after the end of the calendar quarter in which you identify the need for the adjustment. A diagnostic linearity check is required within 168 unit or stack operating hours after changing the span value.

5.2 *Sorbent Trap Monitoring Systems.*

5.2.1 Each sorbent trap monitoring system shall be continuously operated and maintained in accordance with Performance Specification (PS) 12B in appendix B to part 60 of this chapter. The QA/QC criteria for routine operation of the system are summarized in Table 12B–1 of PS 12B. Each pair of sorbent traps may be used to sample the stack gas for up to 14 operating days.

5.2.2 For ongoing QA, periodic RATAs of the system are required.

5.2.2.1 The RATA frequency shall be annual, *i.e.,* once every four QA operating quarters. The provisions in section 5.1.2.4 of this appendix pertaining to RATA deadline extensions also apply to sorbent trap monitoring systems.

5.2.2.2 The same RATA performance criteria specified in Table A–4 for Hg CEMS shall apply to the annual RATAs of the sorbent trap monitoring system.

5.2.2.3 A 720 unit or stack operating hour grace period is available for RATAs of the monitoring system.

5.2.3 Data validation for sorbent trap monitoring systems shall be done in accordance with Table 12B–1 in Performance Specification (PS) 12B in appendix B to part 60 of this chapter. All periods of invalid data shall be counted as hours of monitoring system downtime.

5.3 *Flow Rate, Diluent Gas, and Moisture Monitoring Systems.* The on-going QA test requirements for these monitoring systems are specified in part 75 of this chapter (see §§ 63.10010(b) through (d)).

5.4 *QA/QC Program Requirements.* The owner or operator shall develop and implement a quality assurance/quality control (QA/QC) program for the Hg CEMS and/or sorbent trap monitoring systems that are used to provide data under this subpart. At a minimum, the program shall include a written plan that describes in detail (or that refers to separate documents containing) complete, step-by-step procedures and operations for the most important QA/QC activities. Electronic storage of the QA/QC plan is permissible, provided that the information can be made available in hard copy to auditors and inspectors. The QA/QC program requirements for the diluent gas, flow rate, and moisture monitoring systems described in section 3.2.1.3 of this appendix are specified in section 1 of appendix B to part 75 of this chapter.

5.4.1 *General Requirements.*

5.4.1.1 *Preventive Maintenance.* Keep a written record of procedures needed to maintain the Hg CEMS and/or sorbent trap monitoring system(s) in proper operating condition and a schedule for those procedures. Include, at a minimum, all procedures specified by the manufacturers of the equipment and, if applicable, additional or alternate procedures developed for the equipment.

5.4.1.2 *Recordkeeping and Reporting.* Keep a written record describing procedures that will be used to implement the recordkeeping and reporting requirements of this appendix.

5.4.1.3 *Maintenance Records.* Keep a record of all testing, maintenance, or repair activities performed on any Hg CEMS or sorbent trap monitoring system in a location and format suitable for inspection. A maintenance log may be used for this purpose. The following records should be maintained: date, time, and description of any testing, adjustment, repair, replacement, or preventive maintenance action performed on any monitoring system and records of any corrective actions associated with a monitor outage period. Additionally, any adjustment that may significantly affect a system's ability to accurately measure emissions data must be

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recorded (*e.g.,* changing the dilution ratio of a CEMS), and a written explanation of the procedures used to make the adjustment(s) shall be kept.

5.4.2 *Specific Requirements for Hg CEMS.*

5.4.2.1 *Daily Calibrations, Linearity Checks and System Integrity Checks.* Keep a written record of the procedures used for daily calibrations of the Hg CEMS. If moisture and/or chlorine is added to the Hg calibration gas, document how the dilution effect of the moisture and/or chlorine addition on the calibration gas concentration is accounted for in an appropriate manner. Also keep records of the procedures used to perform linearity checks of the Hg CEMS and the procedures for system integrity checks of the Hg CEMS. Document how the test results are calculated and evaluated.

5.4.2.2 *Monitoring System Adjustments.* Document how each component of the Hg CEMS will be adjusted to provide correct responses to calibration gases after routine maintenance, repairs, or corrective actions.

5.4.2.3 *Relative Accuracy Test Audits.* Keep a written record of procedures used for RATAs of the Hg CEMS. Indicate the reference methods used and document how the test results are calculated and evaluated.

5.4.3 *Specific Requirements for Sorbent Trap Monitoring Systems.*

5.4.3.1 *Sorbent Trap Identification and Tracking.* Include procedures for inscribing or otherwise permanently marking a unique identification number on each sorbent trap, for chain of custody purposes. Keep records of the ID of the monitoring system in which each sorbent trap is used, and the dates and hours of each Hg collection period.

5.4.3.2 *Monitoring System Integrity and Data Quality.* Document the procedures used to perform the leak checks when a sorbent trap is placed in service and removed from service. Also Document the other QA procedures used to ensure system integrity and data quality, including, but not limited to, gas flow meter calibrations, verification of moisture removal, and ensuring air-tight pump operation. In addition, the QA plan must include the data acceptance and quality control criteria in Table 12B–1 in section 9.0 of Performance Specification (PS) 12B in Appendix B to part 60 of this chapter. All reference meters used to calibrate the gas flow meters (*e.g.,* wet test meters) shall be periodically recalibrated. Annual, or more frequent, recalibration is recommended. If a NIST-traceable calibration device is used as a reference flow meter, the QA plan must include a protocol for ongoing maintenance and periodic recalibration to maintain the accuracy and NIST-traceability of the calibrator.

5.4.3.3 *Hg Analysis.* Explain the chain of custody employed in packing, transporting, and analyzing the sorbent traps. Keep records of all Hg analyses. The analyses shall be performed in accordance with the procedures described in section 11.0 of Performance Specification (PS) 12B in Appendix B to part 60 of this chapter.

5.4.3.4 *Data Collection Period.* State, and provide the rationale for, the minimum acceptable data collection period (*e.g.,* one day, one week, etc.) for the size of sorbent trap selected for the monitoring. Address such factors as the Hg concentration in the stack gas, the capacity of the sorbent trap, and the minimum mass of Hg required for the analysis. Each pair of sorbent traps may be used to sample the stack gas for up to 14 operating days.

5.4.3.5 *Relative Accuracy Test Audit Procedures.* Keep records of the procedures and details peculiar to the sorbent trap monitoring systems that are to be followed for relative accuracy test audits, such as sampling and analysis methods.

6. Data Reduction and Calculations

6.1 Data Reduction.

6.1.1 Reduce the data from Hg CEMS to hourly averages, in accordance with § 60.13(h)(2) of this chapter.

6.1.2 For sorbent trap monitoring systems, determine the Hg concentration for each data collection period and assign this concentration value to each operating hour in the data collection period.

6.1.3 For any operating hour in which valid data are not obtained, either for Hg concentration or for a parameter used in the emissions calculations (*i.e.,* flow rate, diluent gas concentration, or moisture, as applicable), do not calculate the Hg emission rate for that hour. For the purposes of this appendix, part 75 substitute data values are not considered to be valid data.

6.1.4 Operating hours in which valid data are not obtained for Hg concentration are considered to be hours of monitor downtime. The use of substitute data for Hg concentration is not required.

6.2 *Calculation of Hg Emission Rates.* Use the applicable calculation methods in paragraphs 6.2.1 and 6.2.2 of this section to convert Hg concentration values to the appropriate units of the emission standard.

6.2.1 *Heat Input-Based Hg Emission Rates.* Calculate hourly heat input-based Hg emission rates, in units of lb/TBtu, according to sections 6.2.1.1 through 6.2.1.4 of this appendix.

6.2.1.1 Select an appropriate emission rate equation from among Equations 19–1 through 19–9 in EPA Method 19 in appendix A–7 to part 60 of this chapter.

6.2.1.2 Calculate the Hg emission rate in lb/MMBtu, using the equation selected from Method 19. Multiply the Hg concentration value by 6.24×10^{-11} to convert it from µg/scm to lb/scf. In cases where an appropriate F-factor is not listed in Table 19–2 of Method 19, you may use F-factors from Table 1 in section 3.3.5 of appendix F to part 75 of this chapter, or F-factors derived using the procedures in section 3.3.6 of appendix to part 75 of this chapter. Also, for startup and shutdown hours, you may calculate the Hg emission rate using the applicable diluent cap value specified in section 3.3.4.1 of appendix F to part 75 of this chapter, provided that the diluent gas monitor is not out-of-control and the hourly average O_2 concentration is above 14.0% O_2 (19.0% for an IGCC) or the hourly average CO_2 concentration is below 5.0% CO_2 (1.0% for an IGCC), as applicable.

6.2.1.3 Multiply the lb/MMBtu value obtained in section 6.2.1.2 of this appendix by 10^6 to convert it to lb/TBtu.

6.2.1.4 The heat input-based Hg emission rate limit in Table 2 to this subpart must be met on a 30 boiler operating day rolling average basis. Use Equation 19–19 in EPA Method 19 to calculate the Hg emission rate for each averaging period. The term E_{hj} in Equation 19–19 must be in the units of the applicable emission limit. Do not include non-operating hours with zero emissions in the average.

6.2.2 *Electrical Output-Based Hg Emission Rates.* Calculate electrical output-based Hg emission limits in units of lb/GWh, according to sections 6.2.2.1 through 6.2.2.3 of this appendix.

6.2.2.1 Calculate the Hg mass emissions for each operating hour in which valid data are obtained for all parameters, using Equation A–2 of this section (for wet-basis measurements of Hg concentration) or Equation A–3 of this section (for dry-basis measurements), as applicable:

$$M_h = K C_h Q_h \qquad \text{(Equation A-2)}$$

Where:

M_h = Hg mass emission rate for the hour (lb/h)

K = Units conversion constant, 6.24×10^{-11} lb-scm/µg-scf,

C_h = Hourly average Hg concentration, wet basis (µg/scm)

Q_h = Stack gas volumetric flow rate for the hour (scfh).

(**Note:** Use unadjusted flow rate values; bias adjustment is not required)

$$M_h = K C_h Q_h \left(1 - B_{ws}\right) \qquad \text{(Equation A-3)}$$

Where:

M_h = Hg mass emission rate for the hour (lb/h)

K = Units conversion constant, 6.24×10^{-11} lb-scm/µg-scf.

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C_h = Hourly average Hg concentration, dry basis (μg/dscm).
Q_h = Stack gas volumetric flow rate for the hour (scfh)
(**Note:** Use unadjusted flow rate values; bias adjustment is not required).
B_{ws} = Moisture fraction of the stack gas, expressed as a decimal (equal to % H_2O/100)

6.2.2.2 Use Equation A–4 of this section to calculate the emission rate for each unit or stack operating hour in which valid data are obtained for all parameters.

$$E_{ho} = \frac{M_h}{(MW)_h} x\,10^3 \qquad \text{(Equation A-4)}$$

Where:
E_{ho} = Electrical output-based Hg emission rate (lb/GWh).
M_h = Hg mass emission rate for the hour, from Equation A–2 or A–3 of this section, as applicable (lb/h).
$(MW)_h$ = Gross electrical load for the hour, in megawatts (MW).
10^3 = Conversion factor from megawatts to gigawatts.

6.2.2.3 The applicable electrical output-based Hg emission rate limit in Table 1 or 2 to this subpart must be met on a 30-boiler operating day rolling average basis. Use Equation A–5 of this section to calculate the Hg emission rate for each averaging period.

$$\overline{E}_o = \frac{\sum_{h=1}^{n} E_{ho}}{n} \qquad \text{(Equation A-5)}$$

Where:
$\bar{E}_o$ = Hg emission rate for the averaging period (lb/GWh).
E_{ho} = Electrical output-based hourly Hg emission rate for unit or stack operating hour "h" in the averaging period, from Equation A–4 of this section (lb/GWh).
n = Number of unit or stack operating hours in the averaging period in which valid data were obtained for all parameters (**Note:** Do *not* include non-operating hours with zero emission rates in the average).

7. Recordkeeping and Reporting

7.1 *Recordkeeping Provisions.* For the Hg CEMS and/or sorbent trap monitoring systems and any other necessary monitoring systems installed at each affected unit, the owner or operator must maintain a file of all measurements, data, reports, and other information required by this appendix in a form suitable for inspection, for 5 years from the date of each record, in accordance with § 63.10033. The file shall contain the information in paragraphs 7.1.1 through 7.1.10 of this section.

7.1.1 *Monitoring Plan Records.* For each affected unit or group of units monitored at a common stack, the owner or operator shall prepare and maintain a monitoring plan for the Hg CEMS and/or sorbent trap monitoring system(s) and any other monitoring system(s) (*i.e.,* flow rate, diluent gas, or moisture systems) needed for routine operation of a sorbent trap monitoring system or to convert Hg concentrations to units of the applicable emission standard. The monitoring plan shall contain essential information on the continuous monitoring systems and shall Document how the data derived from these systems ensure that all Hg emissions from the unit or stack are monitored and reported.

7.1.1.1 *Updates.* Whenever the owner or operator makes a replacement, modification, or change in a certified continuous monitoring system that is used to provide data under this subpart (including a change in the automated data acquisition and handling system or the flue gas handling system) which affects information reported in the monitoring plan (*e.g.,* a change to a serial number for a component of a monitoring system), the owner or operator shall update the monitoring plan.

7.1.1.2 *Contents of the Monitoring Plan.* For Hg CEMS and sorbent trap monitoring systems, the monitoring plan shall contain the information in sections 7.1.1.2.1 and 7.1.1.2.2 of this appendix, as applicable. For stack gas flow rate, diluent gas, and moisture monitoring systems, the monitoring plan shall include the information required for those systems under § 75.53 (g) of this chapter.

7.1.1.2.1 *Electronic.* The electronic monitoring plan records must include the following: unit or stack ID number(s); monitoring location(s); the Hg monitoring methodologies used; Hg monitoring system information, including, but not limited to: Unique system and component ID numbers; the make, model, and serial number of the monitoring equipment; the sample acquisition method; formulas used to calculate Hg emissions; Hg monitor span and range information The electronic monitoring plan shall be evaluated and submitted using the Emissions Collection and Monitoring Plan System (ECMPS) Client Tool provided by the Clean Air Markets Division in the Office of Atmospheric Programs of the EPA.

7.1.1.2.2 *Hard Copy.* Keep records of the following: schematics and/or blueprints showing the location of the Hg monitoring system(s) and test ports; data flow diagrams; test protocols; monitor span and range calculations; miscellaneous technical justifications.

7.1.2 *Operating Parameter Records.* The owner or operator shall record the following information for each operating hour of each affected unit and also for each group of units utilizing a common stack, to the extent that these data are needed to convert Hg concentration data to the units of the emission standard. For non-operating hours, record only the items in paragraphs 7.1.2.1 and 7.1.2.2 of this section. If there is heat input to the unit(s), but no electrical load, record only the items in paragraphs 7.1.2.1, 7.1.2.2, and (if applicable) 7.1.2.4 of this section.

7.1.2.1 The date and hour;

7.1.2.2 The unit or stack operating time (rounded up to the nearest fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator);

7.1.2.3 The hourly gross unit load (rounded to nearest MWe); and

7.1.2.4 If applicable, the F-factor used to calculate the heat input-based Hg emission rate.

7.1.3 *Hg Emissions Records (Hg CEMS).* For each affected unit or common stack using a Hg CEMS, the owner or operator shall record the following information for each unit or stack operating hour:

7.1.3.1 The date and hour;

7.1.3.2 Monitoring system and component identification codes, as provided in the monitoring plan, if the CEMS provides a quality-assured value of Hg concentration for the hour;

7.1.3.3 The hourly Hg concentration, if a quality-assured value is obtained for the hour (μg/scm, rounded to three significant figures);

7.1.3.4 A special code, indicating whether or not a quality-assured Hg concentration is obtained for the hour. This code may be entered manually when a temporary like-kind replacement Hg analyzer is used for reporting; and

7.1.3.5 Monitor data availability, as a percentage of unit or stack operating hours, calculated according to § 75.32 of this chapter.

7.1.4 *Hg Emissions Records (Sorbent Trap Monitoring Systems).* For each affected unit or common stack using a sorbent trap monitoring system, each owner or operator shall record the following information for the unit or stack operating hour in each data collection period:

7.1.4.1 The date and hour;

7.1.4.2 Monitoring system and component identification codes, as provided in the monitoring plan, if the sorbent trap

system provides a quality-assured value of Hg concentration for the hour;

7.1.4.3 The hourly Hg concentration, if a quality-assured value is obtained for the hour (μg/scm, rounded to three significant figures). Note that when a quality-assured Hg concentration value is obtained for a particular data collection period, that single concentration value is applied to each operating hour of the data collection period.

7.1.4.4 A special code, indicating whether or not a quality-assured Hg concentration is obtained for the hour;

7.1.4.5 The average flow rate of stack gas through each sorbent trap (in appropriate units, *e.g.,* liters/min, cc/min, dscm/min);

7.1.4.6 The gas flow meter reading (in dscm, rounded to the nearest hundredth), at the beginning and end of the collection period and at least once in each unit operating hour during the collection period;

7.1.4.7 The ratio of the stack gas flow rate to the sample flow rate, as described in section 12.2 of Performance Specification (PS) 12B in Appendix B to part 60 of this chapter; and

7.1.4.8 Monitor data availability, as a percentage of unit or stack operating hours, calculated according to § 75.32 of this chapter.

7.1.5 *Stack Gas Volumetric Flow Rate Records.*

7.1.5.1 Hourly measurements of stack gas volumetric flow rate during unit operation are required for routine operation of sorbent trap monitoring systems, to maintain the required ratio of stack gas flow rate to sample flow rate (see section 8.2.2 of Performance Specification (PS) 12B in Appendix B to part 60 of this chapter). Hourly stack gas flow rate data are also needed in order to demonstrate compliance with electrical output-based Hg emissions limits, as provided in section 6.2.2 of this appendix.

7.1.5.2 For each affected unit or common stack, if hourly measurements of stack gas flow rate are needed for sorbent trap monitoring system operation or to convert Hg concentrations to the units of the emission standard, use a flow rate monitor that meets the requirements of part 75 of this chapter to record the required data. You must keep hourly flow rate records, as specified in § 75.57(c)(2) of this chapter.

7.1.6 *Records of Stack Gas Moisture Content.*

7.1.6.1 Correction of hourly Hg concentration data for moisture is sometimes required when converting Hg concentrations to the units of the applicable Hg emissions limit. In particular, these corrections are required:

7.1.6.1.1 For sorbent trap monitoring systems;

7.1.6.1.2 For Hg CEMS that measure Hg concentration on a dry basis, when you must calculate electrical output-based Hg emission rates; and

7.1.6.1.3 When using certain equations from EPA Method 19 in appendix A–7 to part 60 of this chapter to calculate heat input-based Hg emission rates.

7.1.6.2 If hourly moisture corrections are required, either use a fuel-specific default moisture percentage from § 75.11(b)(1) of this chapter or a certified moisture monitoring system that meets the requirements of part 75 of this chapter, to record the required data. If you use a moisture monitoring system, you must keep hourly records of the stack gas moisture content, as specified in § 75.57(c)(3) of this chapter.

7.1.7 *Records of Diluent Gas (CO_2 or O_2) Concentration.*

7.1.7.1 When a heat input-based Hg mass emissions limit must be met, in units of lb/TBtu, hourly measurements of CO_2 or O_2 concentration are required to convert Hg concentrations to units of the standard.

7.1.7.2 If hourly measurements of diluent gas concentration are needed, use a certified CO_2 or O_2 monitor that meets the requirements of part 75 of this chapter to record the required data. You must keep hourly CO_2 or O_2 concentration records, as specified in § 75.57(g) of this chapter.

7.1.8 *Hg Emission Rate Records.* For applicable Hg emission limits in units of lb/TBtu or lb/GWh, record the following information for each affected unit or common stack:

7.1.8.1 The date and hour;

7.1.8.2 The hourly Hg emissions rate (lb/TBtu or lb/GWh, as applicable, calculated according to section 6.2.1 or 6.2.2 of this appendix, rounded to three significant figures), if valid values of Hg concentration and all other required parameters (stack gas volumetric flow rate, diluent gas concentration, electrical load, and moisture data, as applicable) are obtained for the hour;

7.1.8.3 An identification code for the formula (either the selected equation from Method 19 in section 6.2.1 of this appendix or Equation A–4 in section 6.2.2 of this appendix) used to derive the hourly Hg emission rate from Hg concentration, flow rate, electrical load, diluent gas concentration, and moisture data (as applicable); and

7.1.8.4 A code indicating that the Hg emission rate was not calculated for the hour, if valid data for Hg concentration and/or any of the other necessary parameters are not obtained for the hour. For the purposes of this appendix, the substitute data values required under part 75 of this chapter for diluent gas concentration, stack gas flow rate and moisture content are not considered to be valid data.

7.1.9 *Certification and Quality Assurance Test Records.* For any Hg CEMS and sorbent trap monitoring systems used to provide data under this subpart, record the following certification and quality-assurance information:

7.1.9.1 The reference values, monitor responses, and calculated calibration error (CE) values, and a flag to indicate whether the test was done using elemental or oxidized Hg, for all required 7-day calibration error tests and daily calibration error tests of the Hg CEMS;

7.1.9.2 The reference values, monitor responses, and calculated linearity error (LE) or system integrity error (SIE) values for all linearity checks of the Hg CEMS, and for all single-level and 3-level system integrity checks of the Hg CEMS;

7.1.9.3 The CEMS and reference method readings for each test run and the calculated relative accuracy results for all RATAs of the Hg CEMS and/or sorbent trap monitoring systems;

7.1.9.4 The stable stack gas and calibration gas readings and the calculated results for the upscale and downscale stages of all required cycle time tests of the Hg CEMS or, for a batch sampling Hg CEMS, the interval between measured Hg concentration readings;

7.1.9.5 Supporting information for all required RATAs of the Hg monitoring systems, including records of the test dates, the raw reference method and monitoring system data, the results of sample analyses to substantiate the reported test results, and records of sampling equipment calibrations;

7.1.9.6 For sorbent trap monitoring systems, also keep records of the results of all analyses of the sorbent traps used for routine daily operation of the system, and information documenting the results of all leak checks and the other applicable quality control procedures described in Table 12B–1 of Performance Specification (PS) 12B in appendix B to part 60 of this chapter.

7.1.9.7 For stack gas flow rate, diluent gas, and (if applicable) moisture monitoring systems, you must keep records of all certification, recertification, diagnostic, and on-going quality-assurance tests of these systems, as specified in § 75.59 of this chapter.

7.2 *Reporting Requirements.*

7.2.1 *General Reporting Provisions.* The owner or operator shall comply with the following requirements for reporting Hg emissions from each affected unit (or group of units monitored at a common stack) under this subpart:

7.2.1.1 Notifications, in accordance with paragraph 7.2.2 of this section;

7.2.1.2 Monitoring plan reporting, in accordance with paragraph 7.2.3 of this section;

7.2.1.3 Certification, recertification, and QA test submittals, in accordance with paragraph 7.2.4 of this section; and

7.2.1.4 Electronic quarterly report submittals, in accordance with paragraph 7.2.5 of this section.

7.2.2 *Notifications.* The owner or operator shall provide notifications for each affected unit (or group of units monitored at a common stack) under this subpart in accordance with § 63.10030.

7.2.3 *Monitoring Plan Reporting.* For each affected unit (or group of units monitored at a common stack) under this subpart using Hg CEMS or sorbent trap monitoring system to measure Hg emissions, the owner or operator shall make electronic and hard copy monitoring plan submittals as follows:

7.2.3.1 Submit the electronic and hard copy information in section 7.1.1.2 of this appendix pertaining to the Hg monitoring systems at least 21 days prior to the applicable date in § 63.9984. Also submit the monitoring plan information in § 75.53.(g) pertaining to the flow rate, diluent gas, and moisture monitoring systems within that same time frame, if the required records are not already in place.

7.2.3.2 Whenever an update of the monitoring plan is required, as provided in paragraph 7.1.1.1 of this section. An electronic monitoring plan information

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update must be submitted either prior to or concurrent with the quarterly report for the calendar quarter in which the update is required.

7.2.3.3 All electronic monitoring plan submittals and updates shall be made to the Administrator using the ECMPS Client Tool. Hard copy portions of the monitoring plan shall be kept on record according to section 7.1 of this appendix.

7.2.4 *Certification, Recertification, and Quality-Assurance Test Reporting.* Except for daily QA tests of the required monitoring systems (*i.e.,* calibration error tests and flow monitor interference checks), the results of all required certification, recertification, and quality-assurance tests described in paragraphs 7.1.10.1 through 7.1.10.7 of this section (except for test results previously submitted, *e.g.,* under the ARP) shall be submitted electronically, using the ECMPS Client Tool, either prior to or concurrent with the relevant quarterly electronic emissions report.

7.2.5 *Quarterly Reports.*

7.2.5.1 Beginning with the report for the calendar quarter in which the initial compliance demonstration is completed or the calendar quarter containing the applicable date in § 63.9984, the owner or operator of any affected unit shall use the ECMPS Client Tool to submit electronic quarterly reports to the Administrator, in an XML format specified by the Administrator, for each affected unit (or group of units monitored at a common stack) under this subpart.

7.2.5.2 The electronic reports must be submitted within 30 days following the end of each calendar quarter, except for units that have been placed in long-term cold storage.

7.2.5.3 Each electronic quarterly report shall include the following information:

7.2.5.3.1 The date of report generation;

7.2.5.3.2 Facility identification information;

7.2.5.3.3 The information in paragraphs 7.1.2 through 7.1.8 of this section, as applicable to the Hg emission measurement methodology (or methodologies) used and the units of the Hg emission standard(s); and

7.2.5.3.4 The results of all daily calibration error tests of the Hg CEMS, as described in paragraph 7.1.90.1 of this section and (if applicable) the results of all daily flow monitor interference checks.

7.2.5.4 *Compliance Certification.* Based on reasonable inquiry of those persons with primary responsibility for ensuring that all Hg emissions from the affected unit(s) under this subpart have been correctly and fully monitored, the owner or operator shall submit a compliance certification in support of each electronic quarterly emissions monitoring report. The compliance certification shall include a statement by a responsible official with that official's name, title, and signature, certifying that, to the best of his or her knowledge, the report is true, accurate, and complete.

Appendix B to Subpart UUUUU—HCl and HF Monitoring Provisions

1. Applicability

These monitoring provisions apply to the measurement of HCl and/or HF emissions from electric utility steam generating units, using CEMS. The CEMS must be capable of measuring HCl and/or HF in the appropriate units of the applicable emissions standard (e.g., lb/MMBtu, lb/MWh, or lb/GWh).

2. Monitoring of HCl and/or HF Emissions

2.1 *Monitoring System Installation Requirements.* Install HCl and/or HF CEMS and any additional monitoring systems needed to convert pollutant concentrations to units of the applicable emissions limit in accordance with Performance Specification 15 for extractive Fourier Transform Infrared Spectroscopy (FTIR) continuous emissions monitoring systems in appendix B to part 60 of this chapter and § 63.10010(a).

2.2 *Primary and Backup Monitoring Systems.* The provisions pertaining to primary and redundant backup monitoring systems in section 2.2 of appendix A to this subpart apply to HCl and HF CEMS and any additional monitoring systems needed to convert pollutant concentrations to units of the applicable emissions limit.

2.3 *FTIR Monitoring System Equipment, Supplies, Definitions, and General Operation.* The provisions of Performance Specification 15 Sections 2.0, 3.0, 4.0, 5.0, 6.0, and 10.0 apply.

3. Initial Certification Procedures

The initial certification procedures for the HCl or HF CEMS used to provide data under this subpart are as follows:

3.1 The HCl and/or HF CEMS must be certified according to Performance Specification 15 using the procedures for gas auditing and comparison to a reference method (RM) as specified in sections 3.1.1 and 3.1.2 below. (**Please Note:** EPA plans to publish a technology neutral performance specification and appropriate on-going quality-assurance requirements for HCl CEMS in the near future along with amendments to this appendix to accommodate their use.)

3.1.1 You must conduct a gas audit of the HCl and/or HF CEMS as described in section 9.1 of Performance Specification 15, with the exceptions listed in sections 3.1.2.1 and 3.1.2.2 below.

3.1.1.1 The audit sample gas does not have to be obtained from the Administrator; however, it must be (1) from a secondary source of certified gases (i.e., independent of any calibration gas used for the daily calibration assessments) and (2) directly traceable to National Institute of Standards and Technology (NIST) or VSL Dutch Metrology Institute (VSL) reference materials through an unbroken chain of comparisons. If audit gas traceable to NIST or VSL reference materials is not available, you may use a gas with a concentration certified to a specified uncertainty by the gas manufacturer.

3.1.1.2 Analyze the results of the gas audit using the calculations in section 12.1 of Performance Specification 15. The calculated correction factor (CF) from Eq. 6 of Performance Specification 15 must be between 0.85 and 1.15. You do not have to test the bias for statistical significance.

3.1.2 You must perform a relative accuracy test audit or RATA according to section 11.1.1.4 of Performance Specification 15 and the requirements below. Perform the RATA of the HCl or HF CEMS at normal load. Acceptable HCl/HF reference methods (RM) are Methods 26 and 26A in appendix A–8 to part 60 of this chapter, Method 320 in Appendix A to this part, or ASTM D6348–03 (Reapproved 2010) "Standard Test Method for Determination of Gaseous Compounds by Extractive Direct Interface Fourier Transform Infrared (FTIR) Spectroscopy" (incorporated by reference, see § 63.14), each applied based on the criteria set forth in Table 5 of this subpart.

3.1.2.1 When ASTM D6348–03 is used as the RM, the following conditions must be met:

3.1.2.1.1 The test plan preparation and implementation in the Annexes to ASTM D6348–03, Sections A1 through A8 are mandatory;

3.1.2.1.2 In ASTM D6348–03 Annex A5 (Analyte Spiking Technique), the percent (%) R must be determined for each target analyte (see Equation A5.5);

3.1.2.1.3 For the ASTM D6348–03 test data to be acceptable for a target analyte, %R must be 70% ≥ R ≤ 130%; and

3.1.2.1.4 The %R value for each compound must be reported in the test report and all field measurements corrected with the calculated %R value for that compound using the following equation:

$$\text{Reported Result} = \frac{(\text{Measured Concentration in Stack})}{\%R} x\,100 \qquad \text{(Eq. B-1)}$$

3.1.2.2 The relative accuracy (RA) of the HCl or HF CEMS must be no greater than 20 percent of the mean value of the RM test data in units of ppm on the same moisture basis. Alternatively, if the mean RM value is less than 1.0 ppm, the RA results are acceptable if the absolute value of the difference between the mean RM and CEMS values does not exceed 0.20 ppm.

3.2 Any additional stack gas flow rate, diluent gas, and moisture monitoring system(s) needed to express pollutant concentrations in units of the applicable emissions limit must be certified according to part 75 of this chapter.

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4. Recertification Procedures

Whenever the owner or operator makes a replacement, modification, or change to a certified CEMS that may significantly affect the ability of the system to accurately measure or record pollutant or diluent gas concentrations, stack gas flow rates, or stack gas moisture content, the owner or operator shall recertify the monitoring system. Furthermore, whenever the owner or operator makes a replacement, modification, or change to the flue gas handling system or the unit operation that may significantly change the concentration or flow profile, the owner or operator shall recertify the monitoring system. The same tests performed for the initial certification of the monitoring system shall be repeated for recertification, unless otherwise specified by the Administrator. Examples of changes that require recertification include: Replacement of a gas analyzer; complete monitoring system replacement, and changing the location or orientation of the sampling probe.

5. On-Going Quality Assurance Requirements

5.1 For on-going QA test requirements for HCl and HF CEMS, implement the quality assurance/quality control procedures of Performance Specification 15 of appendix B to part 60 of this chapter as set forth in sections 5.1.1 through 5.1.3 and 5.3.2 of this appendix.

5.1.1 On a daily basis, you must assess the calibration error of the HCl or HF CEMS using either a calibration transfer standard as specified in Performance Specification 15 Section 10.1 which references Section 4.5 of the FTIR Protocol or a HCl and/or HF calibration gas at a concentration no greater than two times the level corresponding to the applicable emission limit. A calibration transfer standard is a substitute calibration compound chosen to ensure that the FTIR is performing well at the wavelength regions used for analysis of the target analytes. The measured concentration of the calibration transfer standard or HCl and/or HF calibration gas results must agree within ± 5 percent of the reference gas value after correction for differences in pressure.

5.1.2 On a quarterly basis, you must conduct a gas audit of the HCl and/or HF CEMS as described in section 3.1.1 of this appendix. For the purposes of this appendix, "quarterly" means once every "QA operating quarter" (as defined in section 3.1.20 of appendix A to this subpart). You have the option to use HCl gas in lieu of HF gas for conducting this audit on an HF CEMS. To the extent practicable, perform consecutive quarterly gas audits at least 30 days apart. The initial quarterly audit is due in the first QA operating quarter following the calendar quarter in which certification testing of the CEMS is successfully completed. Up to three consecutive exemptions from the quarterly audit requirement are allowed for "non-QA operating quarters" (*i.e.,* calendar quarters in which there are less than 168 unit or stack operating hours). However, no more than four consecutive calendar quarters may elapse without performing a gas audit, except as otherwise provided in section 5.3.3.2.1 of this appendix.

5.1.3 You must perform an annual relative accuracy test audit or RATA of the HCl or HF CEMS as described in section 3.1.2 of this appendix. Perform the RATA at normal load. For the purposes of this appendix, "annual" means once every four "QA operating quarters" (as defined in section 3.1.20 of appendix A to this subpart). The first annual RATA is due within four QA operating quarters following the calendar quarter in which the initial certification testing of the HCl or HF CEMS is successfully completed. The provisions in section 5.1.2.4 of appendix A to this subpart pertaining to RATA deadline extensions also apply.

5.2 Stack gas flow rate, diluent gas, and moisture monitoring systems must meet the applicable on-going QA test requirements of part 75 of this chapter.

5.3 *Data Validation.*

5.3.1 *Out-of-Control Periods.* A HCl or HF CEMS that is used to provide data under this appendix is considered to be out-of-control, and data from the CEMS may not be reported as quality-assured, when any acceptance criteria for a required QA test is not met. The HCl or HF CEMS is also considered to be out-of-control when a required QA test is not performed on schedule or within an allotted grace period. To end an out-of-control period, the QA test that was either failed or not done on time must be performed and passed. Out-of-control periods are counted as hours of monitoring system downtime.

5.3.2 *Grace Periods.* For the purposes of this appendix, a "grace period" is defined as a specified number of unit or stack operating hours after the deadline for a required quality-assurance test of a continuous monitor has passed, in which the test may be performed and passed without loss of data.

5.3.2.1 For the flow rate, diluent gas, and moisture monitoring systems described in section 5.2 of this appendix, a 168 unit or stack operating hour grace period is available for quarterly linearity checks, and a 720 unit or stack operating hour grace period is available for RATAs, as provided, respectively, in sections 2.2.4 and 2.3.3 of appendix B to part 75 of this chapter.

5.3.2.2 For the purposes of this appendix, if the deadline for a required gas audit or RATA of a HCl or HF CEMS cannot be met due to circumstances beyond the control of the owner or operator:

5.3.2.2.1 A 168 unit or stack operating hour grace period is available in which to perform the gas audit; or

5.3.2.2.2 A 720 unit or stack operating hour grace period is available in which to perform the RATA.

5.3.2.3 If a required QA test is performed during a grace period, the deadline for the next test shall be determined as follows:

5.3.2.3.1 For a gas audit or RATA of the monitoring systems described in section 5.1 of this appendix, determine the deadline for the next gas audit or RATA (as applicable) in accordance with section 2.2.4(b) or 2.3.3(d) of appendix B to part 75 of this chapter; treat a gas audit in the same manner as a linearity check.

5.3.2.3.2 For the gas audit of a HCl or HF CEMS, the grace period test only satisfies the audit requirement for the calendar quarter in which the test was originally due. If the calendar quarter in which the grace period audit is performed is a QA operating quarter, an additional gas audit is required for that quarter.

5.3.2.3.3 For the RATA of a HCl or HF CEMS, the next RATA is due within three QA operating quarters after the calendar quarter in which the grace period test is performed.

5.3.4 *Conditional Data Validation.* For recertification and diagnostic testing of the monitoring systems that are used to provide data under this appendix, and for the required QA tests when non-redundant backup monitoring systems or temporary like-kind replacement analyzers are brought into service, the conditional data validation provisions in §§ 75.20(b)(3)(ii) through (b)(3)(ix) of this chapter may be used to avoid or minimize data loss. The allotted window of time to complete calibration tests and RATAs shall be as specified in § 75.20(b)(3)(iv) of this chapter; the allotted window of time to complete a gas audit shall be the same as for a linearity check (*i.e.,* 168 unit or stack operating hours).

6. Missing Data Requirements

For the purposes of this appendix, the owner or operator of an affected unit shall not substitute for missing data from HCl or HF CEMS. Any process operating hour for which quality-assured HCl or HF concentration data are not obtained is counted as an hour of monitoring system downtime.

7. Bias Adjustment

Bias adjustment of hourly emissions data from a HCl or HF CEMS is not required.

8. QA/QC Program Requirements

The owner or operator shall develop and implement a quality assurance/quality control (QA/QC) program for the HCl and/or HF CEMS that are used to provide data under this subpart. At a minimum, the program shall include a written plan that describes in detail (or that refers to separate documents containing) complete, step-by-step procedures and operations for the most important QA/QC activities. Electronic storage of the QA/QC plan is permissible, provided that the information can be made available in hard copy to auditors and inspectors. The QA/QC program requirements for the other monitoring systems described in section 5.2 of this appendix are specified in section 1 of appendix B to part 75 of this chapter.

8.1 *General Requirements for HCl and HF CEMS.*

8.1.1 *Preventive Maintenance.* Keep a written record of procedures needed to maintain the HCl and/or HF CEMS in proper operating condition and a schedule for those procedures. This shall, at a minimum, include procedures specified by the manufacturers of the equipment and, if applicable, additional or alternate procedures developed for the equipment.

8.1.2 *Recordkeeping and Reporting.* Keep a written record describing procedures that will be used to implement the recordkeeping and reporting requirements of this appendix.

8.1.3 *Maintenance Records.* Keep a record of all testing, maintenance, or repair

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activities performed on any HCl or HF CEMS in a location and format suitable for inspection. A maintenance log may be used for this purpose. The following records should be maintained: Date, time, and description of any testing, adjustment, repair, replacement, or preventive maintenance action performed on any monitoring system and records of any corrective actions associated with a monitor outage period. Additionally, any adjustment that may significantly affect a system's ability to accurately measure emissions data must be recorded and a written explanation of the procedures used to make the adjustment(s) shall be kept.

8.2 *Specific Requirements for HCl and HF CEMS.* The following requirements are specific to HCl and HF CEMS:

8.2.1 Keep a written record of the procedures used for each type of QA test required for each HCl and HF CEMS. Explain how the results of each type of QA test are calculated and evaluated.

8.2.2 Explain how each component of the HCl and/or HF CEMS will be adjusted to provide correct responses to calibration gases after routine maintenance, repairs, or corrective actions.

9. Data Reduction and Calculations

9.1 Design and operate the HCl and/or HF CEMS to complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period.

9.2 Reduce the HCl and/or HF concentration data to hourly averages in accordance with § 60.13(h)(2) of this chapter.

9.3 Convert each hourly average HCl or HF concentration to an HCl or HF emission rate expressed in units of the applicable emissions limit.

9.3.1 For heat input-based emission rates, select an appropriate emission rate equation from among Equations 19–1 through 19–9 in EPA Method 19 in appendix A–7 to part 60 of this chapter, to calculate the HCl or HF emission rate in lb/MMBtu. Multiply the HCl concentration value (ppm) by 9.43×10^{-8} to convert it to lb/scf, for use in the applicable Method 19 equation. For HF, the conversion constant from ppm to lb/scf is 5.18×10^{-8}.

9.3.2 For electrical output-based emission rates, first calculate the HCl or HF mass emission rate (lb/h), using an equation that has the general form of Equation A–2 or A–3 in appendix A to this subpart (as applicable), replacing the value of K with 9.43×10^{-8} lb/scf-ppm (for HCl) or 5.18×10^{-8} (for HF) and defining C_h as the hourly average HCl or HF concentration in ppm. Then, use Equation A–4 in appendix A to this subpart to calculate the HCl or HF emission rate in lb/GWh. If the applicable HCl or HF limit is expressed in lb/MWh, divide the result from Equation A–4 by 10^3.

9.4 Use Equation A–5 in appendix A of this subpart to calculate the required 30 operating day rolling average HCl or HF emission rates. Round off each 30 operating day average to two significant figures. The term E_{ho} in Equation A–5 must be in the units of the applicable emissions limit.

10. Recordkeeping Requirements

10.1 For each HCl or HF CEMS installed at an affected source, and for any other monitoring system(s) needed to convert pollutant concentrations to units of the applicable emissions limit, the owner or operator must maintain a file of all measurements, data, reports, and other information required by this appendix in a form suitable for inspection, for 5 years from the date of each record, in accordance with § 63.10033. The file shall contain the information in paragraphs 10.1.1 through 10.1.8 of this section.

10.1.1 *Monitoring Plan Records.* For each affected unit or group of units monitored at a common stack, the owner or operator shall prepare and maintain a monitoring plan for the HCl and/or HF CEMS and any other monitoring system(s) (*i.e,* flow rate, diluent gas, or moisture systems) needed to convert pollutant concentrations to units of the applicable emission standard. The monitoring plan shall contain essential information on the continuous monitoring systems and shall explain how the data derived from these systems ensure that all HCl or HF emissions from the unit or stack are monitored and reported.

10.1.1.1 *Updates.* Whenever the owner or operator makes a replacement, modification, or change in a certified continuous HCl or HF monitoring system that is used to provide data under this subpart (including a change in the automated data acquisition and handling system or the flue gas handling system) which affects information reported in the monitoring plan (*e.g.,* a change to a serial number for a component of a monitoring system), the owner or operator shall update the monitoring plan.

10.1.1.2 *Contents of the Monitoring Plan.* For HCl and/or HF CEMS, the monitoring plan shall contain the applicable electronic and hard copy information in sections 10.1.1.2.1 and 10.1.1.2.2 of this appendix. For stack gas flow rate, diluent gas, and moisture monitoring systems, the monitoring plan shall include the electronic and hard copy information required for those systems under § 75.53 (g) of this chapter. The electronic monitoring plan shall be evaluated using the ECMPS Client Tool.

10.1.1.2.1 *Electronic.* Record the unit or stack ID number(s); monitoring location(s); the HCl or HF monitoring methodology used (*i.e.,* CEMS); HCl or HF monitoring system information, including, but not limited to: unique system and component ID numbers; the make, model, and serial number of the monitoring equipment; the sample acquisition method; formulas used to calculate emissions; monitor span and range information (if applicable).

10.1.1.2.2 *Hard Copy.* Keep records of the following: schematics and/or blueprints showing the location of the monitoring system(s) and test ports; data flow diagrams; test protocols; monitor span and range calculations (if applicable); miscellaneous technical justifications.

10.1.2 *Operating Parameter Records.* For the purposes of this appendix, the owner or operator shall record the following information for each operating hour of each affected unit or group of units utilizing a common stack, to the extent that these data are needed to convert pollutant concentration data to the units of the emission standard. For non-operating hours, record only the items in paragraphs 10.1.2.1 and 10.1.2.2 of this section. If there is heat input to the unit(s), but no electrical load, record only the items in paragraphs 10.1.2.1, 10.1.2.2, and (if applicable) 10.1.2.4 of this section.

10.1.2.1 The date and hour;

10.1.2.2 The unit or stack operating time (rounded up to the nearest fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator);

10.1.2.3 The hourly gross unit load (rounded to nearest MWge); and

10.1.2.4 If applicable, the F-factor used to calculate the heat input-based pollutant emission rate.

10.1.3 *HCl and/or HF Emissions Records.* For HCl and/or HF CEMS, the owner or operator must record the following information for each unit or stack operating hour:

10.1.3.1 The date and hour;

10.1.3.2 Monitoring system and component identification codes, as provided in the electronic monitoring plan, for each hour in which the CEMS provides a quality-assured value of HCl or HF concentration (as applicable);

10.1.3.3 The pollutant concentration, for each hour in which a quality-assured value is obtained. For HCl and HF, record the data in parts per million (ppm), rounded to three significant figures.

10.1.3.4 A special code, indicating whether or not a quality-assured HCl or HF concentration value is obtained for the hour. This code may be entered manually when a temporary like-kind replacement HCl or HF analyzer is used for reporting; and

10.1.3.5 Monitor data availability, as a percentage of unit or stack operating hours, calculated according to § 75.32 of this chapter.

10.1.4 *Stack Gas Volumetric Flow Rate Records.*

10.1.4.1 Hourly measurements of stack gas volumetric flow rate during unit operation are required to demonstrate compliance with electrical output-based HCl or HF emissions limits (*i.e.,* lb/MWh or lb/GWh).

10.1.4.2 Use a flow rate monitor that meets the requirements of part 75 of this chapter to record the required data. You must keep hourly flow rate records, as specified in § 75.57(c)(2) of this chapter.

10.1.5 *Records of Stack Gas Moisture Content.*

10.1.5.1 Correction of hourly pollutant concentration data for moisture is sometimes required when converting concentrations to the units of the applicable Hg emissions limit. In particular, these corrections are required:

10.1.5.1.1 To calculate electrical output-based pollutant emission rates, when using a CEMS that measures pollutant concentrations on a dry basis; and

10.1.5.1.2 To calculate heat input-based pollutant emission rates, when using certain equations from EPA Method 19 in appendix A–7 to part 60 of this chapter.

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10.1.5.2 If hourly moisture corrections are required, either use a fuel-specific default moisture percentage for coal-fired units from § 75.11(b)(1) of this chapter, an Administrator approved default moisture value for non-coal-fired units (as per paragraph 63.10010(d) of this subpart), or a certified moisture monitoring system that meets the requirements of part 75 of this chapter, to record the required data. If you elect to use a moisture monitoring system, you must keep hourly records of the stack gas moisture content, as specified in § 75.57(c)(3) of this chapter.

10.1.6 *Records of Diluent Gas (CO_2 or O_2) Concentration.*

10.1.6.1 To assess compliance with a heat input-based HCl or HF emission rate limit in units of lb/MMBtu, hourly measurements of CO_2 or O_2 concentration are required to convert pollutant concentrations to units of the standard.

10.1.6.2 If hourly measurements of diluent gas concentration are needed, you must use a certified CO_2 or O_2 monitor that meets the requirements of part 75 of this chapter to record the required data. For all diluent gas monitors, you must keep hourly CO_2 or O_2 concentration records, as specified in § 75.57(g) of this chapter.

10.1.7 *HCl and HF Emission Rate Records.* For applicable HCl and HF emission limits in units of lb/MMBtu, lb/MWh, or lb/GWh, record the following information for each affected unit or common stack:

10.1.7.1 The date and hour;

10.1.7.2 The hourly HCl and/or HF emissions rate (lb/MMBtu, lb/MWh, or lb/GWh, as applicable, rounded to three significant figures), for each hour in which valid values of HCl or HF concentration and all other required parameters (stack gas volumetric flow rate, diluent gas concentration, electrical load, and moisture data, as applicable) are obtained for the hour;

10.1.7.3 An identification code for the formula used to derive the hourly HCl or HF emission rate from HCl or HF concentration, flow rate, electrical load, diluent gas concentration, and moisture data (as applicable); and

10.1.7.4 A code indicating that the HCl or HF emission rate was not calculated for the hour, if valid data for HCl or HF concentration and/or any of the other necessary parameters are not obtained for the hour. For the purposes of this appendix, the substitute data values required under part 75 of this chapter for diluent gas concentration, stack gas flow rate and moisture content are not considered to be valid data.

10.1.8 *Certification and Quality Assurance Test Records.* For the HCl and/or HF CEMS used to provide data under this subpart at each affected unit (or group of units monitored at a common stack), record the following information for all required certification, recertification, diagnostic, and quality-assurance tests:

10.1.8.1 *HCl and HF CEMS.*

10.1.8.1.1 For all required daily calibrations (including calibration transfer standard tests) of the HCl or HF CEMS, record the test dates and times, reference values, monitor responses, and calculated calibration error values;

10.1.8.1.2 For gas audits of HCl or HF CEMS, record the date and time of each spiked and unspiked sample, the audit gas reference values and uncertainties. Keep records of all calculations and data analyses required under sections 9.1 and 12.1 of Performance Specification 15, and the results of those calculations and analyses.

10.1.8.1.3 For each RATA of a HCl or HF CEMS, record the date and time of each test run, the reference method(s) used, and the reference method and HCl or HF CEMS values. Keep records of the data analyses and calculations used to determine the relative accuracy.

10.1.8.2 *Additional Monitoring Systems.* For the stack gas flow rate, diluent gas, and moisture monitoring systems described in section 3.2 of this appendix, you must keep records of all certification, recertification, diagnostic, and on-going quality-assurance tests of these systems, as specified in § 75.59(a) of this chapter.

11. Reporting Requirements

11.1 *General Reporting Provisions.* The owner or operator shall comply with the following requirements for reporting HCl and/or HF emissions from each affected unit (or group of units monitored at a common stack):

11.1.1 Notifications, in accordance with paragraph 11.2 of this section;

11.1.2 Monitoring plan reporting, in accordance with paragraph 11.3 of this section;

11.1.3 Certification, recertification, and QA test submittals, in accordance with paragraph 11.4 of this section; and

11.1.4 Electronic quarterly report submittals, in accordance with paragraph 11.5 of this section.

11.2 *Notifications.* The owner or operator shall provide notifications for each affected unit (or group of units monitored at a common stack) in accordance with § 63.10030.

11.3 *Monitoring Plan Reporting.* For each affected unit (or group of units monitored at a common stack) using HCl and/or HF CEMS, the owner or operator shall make electronic and hard copy monitoring plan submittals as follows:

11.3.1 Submit the electronic and hard copy information in section 10.1.1.2 of this appendix pertaining to the HCl and/or HF monitoring systems at least 21 days prior to the applicable date in § 63.9984. Also, if applicable, submit monitoring plan information pertaining to any required flow rate, diluent gas, and/or moisture monitoring systems within that same time frame, if the required records are not already in place.

11.3.2 Update the monitoring plan when required, as provided in paragraph 10.1.1.1 of this appendix. An electronic monitoring plan information update must be submitted either prior to or concurrent with the quarterly report for the calendar quarter in which the update is required.

11.3.3 All electronic monitoring plan submittals and updates shall be made to the Administrator using the ECMPS Client Tool. Hard copy portions of the monitoring plan shall be kept on record according to section 10.1 of this appendix.

11.4 *Certification, Recertification, and Quality-Assurance Test Reporting Requirements.* Except for daily QA tests (*i.e.,* calibrations and flow monitor interference checks), which are included in each electronic quarterly emissions report, use the ECMPS Client Tool to submit the results of all required certification, recertification, quality-assurance, and diagnostic tests of the monitoring systems required under this appendix electronically, either prior to or concurrent with the relevant quarterly electronic emissions report.

11.4.1 For daily calibrations (including calibration transfer standard tests), report the information in § 75.59(a)(1) of this chapter, excluding paragraphs (a)(1)(ix) through (a)(1)(xi).

11.4.2 For each quarterly gas audit of a HCl or HF CEMS, report:

11.4.2.1 Facility ID information;

11.4.2.2 Monitoring system ID number;

11.4.2.3 Type of test (*e.g.,* quarterly gas audit);

11.4.2.4 Reason for test;

11.4.2.5 Certified audit (spike) gas concentration value (ppm);

11.4.2.6 Measured value of audit (spike) gas, including date and time of injection;

11.4.2.7 Calculated dilution ratio for audit (spike) gas;

11.4.2.8 Date and time of each spiked flue gas sample;

11.4.2.9 Date and time of each unspiked flue gas sample;

11.4.2.10 The measured values for each spiked gas and unspiked flue gas sample (ppm);

11.4.2.11 The mean values of the spiked and unspiked sample concentrations and the expected value of the spiked concentration as specified in section 12.1 of Performance Specification 15 (ppm);

11.4.2.12 Bias at the spike level as calculated using equation 3 in section 12.1 of Performance Specification 15; and

11.4.2.13 The correction factor (CF), calculated using equation 6 in section 12.1 of Performance Specification 15.

11.4.3 For each RATA of a HCl or HF CEMS, report:

11.4.3.1 Facility ID information;

11.4.3.2 Monitoring system ID number;

11.4.3.3 Type of test (i.e., initial or annual RATA);

11.4.3.4 Reason for test;

11.4.3.5 The reference method used;

11.4.3.6 Starting and ending date and time for each test run;

11.4.3.7 Units of measure;

11.4.3.8 The measured reference method and CEMS values for each test run, on a consistent moisture basis, in appropriate units of measure;

11.4.3.9 Flags to indicate which test runs were used in the calculations;

11.4.3.10 Arithmetic mean of the CEMS values, of the reference method values, and of their differences;

11.4.3.11 Standard deviation, as specified in Equation 2–4 of Performance Specification 2 in appendix B to part 60 of this chapter;

11.4.3.12 Confidence coefficient, as specified in Equation 2–5 of Performance Specification 2 in appendix B to part 60 of this chapter; and

11.4.3.13 Relative accuracy calculated using Equation 2–6 of Performance Specification 2 in appendix B to part 60 of this chapter or, if applicable, according to the alternative procedure for low emitters described in section 3.1.2.2 of this appendix. If applicable use a flag to indicate that the alternative RA specification for low emitters has been applied.

11.4.4 *Reporting Requirements for Diluent Gas, Flow Rate, and Moisture Monitoring Systems.* For the certification, recertification, diagnostic, and QA tests of stack gas flow rate, moisture, and diluent gas monitoring systems that are certified and quality-assured according to part 75 of this chapter, report the information in section 10.1.9.3 of this appendix.

11.5 *Quarterly Reports.*

11.5.1 Beginning with the report for the calendar quarter in which the initial compliance demonstration is completed or the calendar quarter containing the applicable date in § 63.10005(g), (h), or (j) (whichever is earlier), the owner or operator of any affected unit shall use the ECMPS Client Tool to submit electronic quarterly reports to the Administrator, in an XML format specified by the Administrator, for each affected unit (or group of units monitored at a common stack).

11.5.2 The electronic reports must be submitted within 30 days following the end of each calendar quarter, except for units that have been placed in long-term cold storage.

11.5.3 Each electronic quarterly report shall include the following information:

11.5.3.1 The date of report generation;

11.5.3.2 Facility identification information;

11.5.3.3 The information in sections 10.1.2 through 10.1.7 of this appendix, as applicable to the type(s) of monitoring system(s) used to measure the pollutant concentrations and other necessary parameters.

11.5.3.4 The results of all daily calibrations (including calibration transfer standard tests) of the HCl or HF monitor as described in section 10.1.8.1.1 of this appendix; and

11.5.3.5 If applicable, the results of all daily flow monitor interference checks, in accordance with section 10.1.8.2 of this appendix.

11.5.4 *Compliance Certification.* Based on reasonable inquiry of those persons with primary responsibility for ensuring that all HCl and/or HF emissions from the affected unit(s) have been correctly and fully monitored, the owner or operator shall submit a compliance certification in support of each electronic quarterly emissions monitoring report. The compliance certification shall include a statement by a responsible official with that official's name, title, and signature, certifying that, to the best of his or her knowledge, the report is true, accurate, and complete.

[FR Doc. 2012–806 Filed 2–15–12; 8:45 am]

BILLING CODE 6560–50–P

Responsibility for Minimum Filing Requirements

Schedule	Title
C-6	Budgeted Versus Actual Operating Revenues and Expenses
C-8	Detail of Changes in Expenses
C-9	Five Year Analysis – Change in Cost
C-34	Statistical Information
C-41	O&M Benchmark Variance by Function
F-8	Assumptions

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130140-EI EXHIBIT 11
PARTY Gulf Power Company (Gulf) Direct
DESCRIPTION P. Chris Caldwell (PCC-1)

Budgeted Transmission Capital Expenditures by Category

Budgeted Transmission Expenditures by Category ($1,000s)		
Category	**2013 Budget**	**2014 Budget**
Distribution Planning	200	100
Transmission Planning	46,497	99,493
Infrastructure Replacement - Blankets	10,880	9,818
Infrastructure Replacement - Specific PE	28,393	5,525
Grand Total	**85,970**	**114,936**

Budgeted Transmission Capital Expenditures for
Infrastructure Replacements – Blanket PEs

Infrastructure Replacements- Blanket Pes ($1,000s)			
PE	**Description**	**2013 Budget**	**2014 Budget**
280101	Transmission Substation Infrastructure Projects	650	650
280201	Transmission 230 kV Line Infrastructure Projects	6,000	5,000
281001	115 kV Static Wire Replacements	515	450
282201	Transmission 115 kV Switch Replacement Project	500	500
283001	Transmission Breaker Replacement	200	200
283501	Critical Infrastructure Protection (CIP)	-	238
340101	Miscellaneous Distribution Substation Additions & Improvements	1,000	1,000
342801	Proactive Transformer Replacement	1,000	1,000
345301	Distribution 12 kV Breaker Replacement Program	315	315
370201	Circuit Switcher Improvements	250	250
371401	Protection & Control Infrastructure Projects	100	100
374201	Energy Management System - Transmission	350	115
		10,880	**9,818**

Florida Public Service Commission
Docket No. 130140-EI
GULF POWER COMPANY
Witness: P. Chris Caldwell
Exhibit ____ (PCC-1)
Schedule 2
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Budgeted Transmission Capital Expenditures for Infrastructure Replacements – Specific PEs

Infrastructure Replacements-Specific Pes ($1,000s)			
PE	**Description**	**2013 Budget**	**2014 Budget**
281201	Transmission Line Switch Replacement (Smart Grid Investment Grant)	580	-
282401	Marianna - Alford 115 kV Reconductor	8,988	-
282701	Navarre - Live Oak Insulator Replace	500	-
284101	Smith - Shoal River 230 kV Guyed Y Tower Anchor Replacements	1,000	-
284102	Smith - Sinia 230 kV Guyed Y Tower Anchor Replacements	-	1,650
286801	Survey And Renewal Of Transmission Corridor Leases	1,500	-
288901	Crist - Air Products 115 kV Rebuild	500	-
341801	Gulf Breeze Reliability Upgrade	320	-
342001	Destin 115 12 kV Reliability Upgrade	-	50
342201	Ocean City Lowside Bus Rebuild	1,400	-
342301	Hathaway 115 12 kV Reliability Upgrade	50	345
342401	Bluewater 115 12 kV New House And Batteries	125	-
342501	Innerarity 115 12 kV Upgrade	50	665
342701	Fort Walton 115 12 kV Reliability Upgrade	50	710
343001	Marianna Breaker Replacement	-	15
343101	Cantonment Lowside Bus Structure Rebuild	3,750	-
343201	Airport Substation Conversion	2,250	-
343202	Airport Substation Conversion	60	-
343501	Brentwood Ds Reliability Upgrade	1,500	-
343601	Cordova 115/12 kV Substation Protection & Control Infrastructure Upgrade	-	20
345001	Honeysuckle Distribution Substation Reliability Upgrade	500	-
346701	Marianna 115/12 kV Substation Protection & Control Infrastructure Upgrade	50	550
348001	Redwood Protection & Control System Replacement	50	-
348201	Air Products Protection & Control System Replacement	-	200
348401	Bayou Chico Protection & Control System Replacement	50	-
348501	Devilliers Protection & Control System Replacement	450	-
348701	Long Beach Protection & Control System Replacement	160	-
349001	Devillers Lowside Bus Structure Rebuild	3,200	-
349401	Pace 115/12 kV Substation Protection & Control Infrastructure Upgrade	-	35
349601	Northside 115/12 kV Substation Protection & Control Infrastructure Upgrade	-	35
373501	Caryville Tap Overhead Ground Wire Addition	975	-
373502	Ponce De Leon Substation	30	625
373503	Caryville Substation	30	625
374801	Fiber Optic Equip	50	-
375601	Optical Ground Wire (Smart Grid Investment Grant)	225	-
		28,393	**5,525**

Budgeted Transmission Capital Expenditures for Planning Generated Projects

Transmission Planning Generated Projects ($1,000s)			
PE	**Description**	**2013 Budget**	**2014 Budget**
282001	Scenic Hills Bus Modifications	3,400	0
282002	Line Connections	260	0
	Pensacola Area - Scenic Hills Total	**3,660**	**0**
280301	Pensacola Svc (Alligator Swamp)	515	10,753
281301	North Brewton - Alligator Swamp 230 Line	513	26,429
284801	Alligator Swamp 90Mvar 230 kV Cap Bank	0	50
285101	West Pensacola Ring Bus And Cap Bank	0	150
	Pensacola Area - Crist Scrubber Total	**1,028**	**37,382**
282101	Loop Crist - Shoal River Into Alligator Swamp	0	125
282102	Alligator Swamp Sub	0	75
	Pensacola Area - Alligator Swamp Total	**0**	**200**
285302	Highland City Substation	8,856	0
285303	Highland City - Callaway Ring Bus	1,980	0
285304	Highland City - Callaway 230 kV Connections	241	0
287403	Smith-Laguna 115 kV Line Conversation - 230 kV Line Terminal	1,773	0
	Panama City Area -Highland City Total	**12,850**	**0**
282901	Panama City Svc (Highland City)	500	10,500
286701	Holmes Creek - Highland City New 230 kV - Line	18,302	19,251
286703	Holmes Creek - Highland City New 230 kV - Autobank	8,093	8,559
286707	Holmes Creek - Highland City New 230 kV - Cap Bank	50	2,072
286709	Rebuild Holmes Creek - Bonifay Tap Section Double Circuit	0	1,518
	Panama City Area - Smith Total	**26,945**	**41,900**
281403	Laguna - Santa Rosa 230 kV Conversion - New 230 kV Line	114	13,882
281407	Laguna - Santa Rosa 230 kV Conversion - New Substation	0	6,129
	Panama City Area - Laguna - Santa Rosa Total	**114**	**20,011**
289001	Slocomb - Holmes Creek 115 kV Rebuild	1,900	0
	Slocomb - Holmes Creek Rebuild Total	**1,900**	**0**
		46,497	**99,493**

Testimony and exhibits of James O. Vick and the testimony of Noel M. Cain were filed on April 1, 2013 in Docket No. 130092. The testimony and exhibits are incorporated herein by reference and have been assigned the document numbers described in the table below.

Document Number (DN)	Description
01557-13	Direct testimony of Noel M. Cain and direct testimony of James O. Vick with exhibits JOV-1 and JOV-2.
01560-13	Request for confidential classification of DN 01561-13 with attached redacted version and line-by-line/field-by-field justification.
01561-13	(CONFIDENTIAL) Certain portions of environmental compliance program in Exhibit JOV-1 to James O. Vick's testimony.

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Exhibit ____ (PCC-1)
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MATS – Planning Projects through 2015

MATS - Planning Projects through 2015			Total In Service Budget	
PE	Description	In Service	2014	2015
280301	Pensacola Svc (Alligator Swamp)	2015		16,509
281301	North Brewton - Alligator Swamp 230 Line	2015		34,002
281302	Alligator Swamp Substation	2015		252
284801	Alligator Swamp 90Mvar 230 kV Cap Bank	2015		2,100
282901	Panama City Svc (Highland City)	2015		16,000
286701	Holmes Creek - Highland City New 230 kV - Line	2015		39,790
286703	Holmes Creek - Highland City New 230 kV - Autobank	2014	16,652	
286707	Holmes Creek - Highland City New 230 kV - Cap Bank	2014	2,122	
286709	Rebuild Holmes Creek - Bonifay Tap Section Double Circuit	2014	1,518	
			20,292	**108,653**

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Witness: P. Chris Caldwell
Exhibit ____ (PCC-1)
Schedule 5
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Gulf Transmission O&M Budget by Category
2013 through 2017
($000)

Category	2013 Budget	2014 Budget	2015 Budget	2016 Budget	2017 Budget
Protection and Control	$343	$354	$363	$371	$379
SGIG	$133	$135	$136	$138	$139
Transmission Control Center	$4,348	$4,619	$4,797	$4,968	$5,128
Transmission Engineering and Supervision	$1,955	$2,091	$2,158	$2,227	$2,281
Transmission Vegetation Management	$1,944	$3,023	$3,023	$3,023	$3,023
Transmission Line Maintenance Programs	$1,522	$1,645	$1,600	$1,580	$1,588
Substation Maintenance Programs	$1,690	$1,866	$1,787	$1,800	$1,821
Total	**$11,935**	**$13,733**	**$13,864**	**$14,107**	**$14,359**

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GULF POWER COMPANY
Witness: P. Chris Caldwell
Exhibit ____ (PCC-1)
Schedule 6
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Gulf Transmission Benchmark Comparison
Test Year Benchmark versus 2014 Budget
($000)

Categories	Test Year Benchmark	2014 Budget	Variance
Protection and Control	$444	$354	($90)
Smart Grid Investment Grant	$142	$135	($7)
Transmission Control Center	$4,707	$4,619	($88)
Transmission Engineering and Supervision	$1,782	$2,091	$309
Transmission Vegetation Management	$2,082	$3,023	$941
Transmission Line Maintenance Programs	$1,062	$1,645	$583
Substation Maintenance Programs	$1,912	$1,866	($46)
Total	**$12,131**	**$13,733**	**$1,602**

Florida Public Service Commission
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GULF POWER COMPANY
Witness: P. Chris Caldwell
Exhibit ____ (PCC-1)
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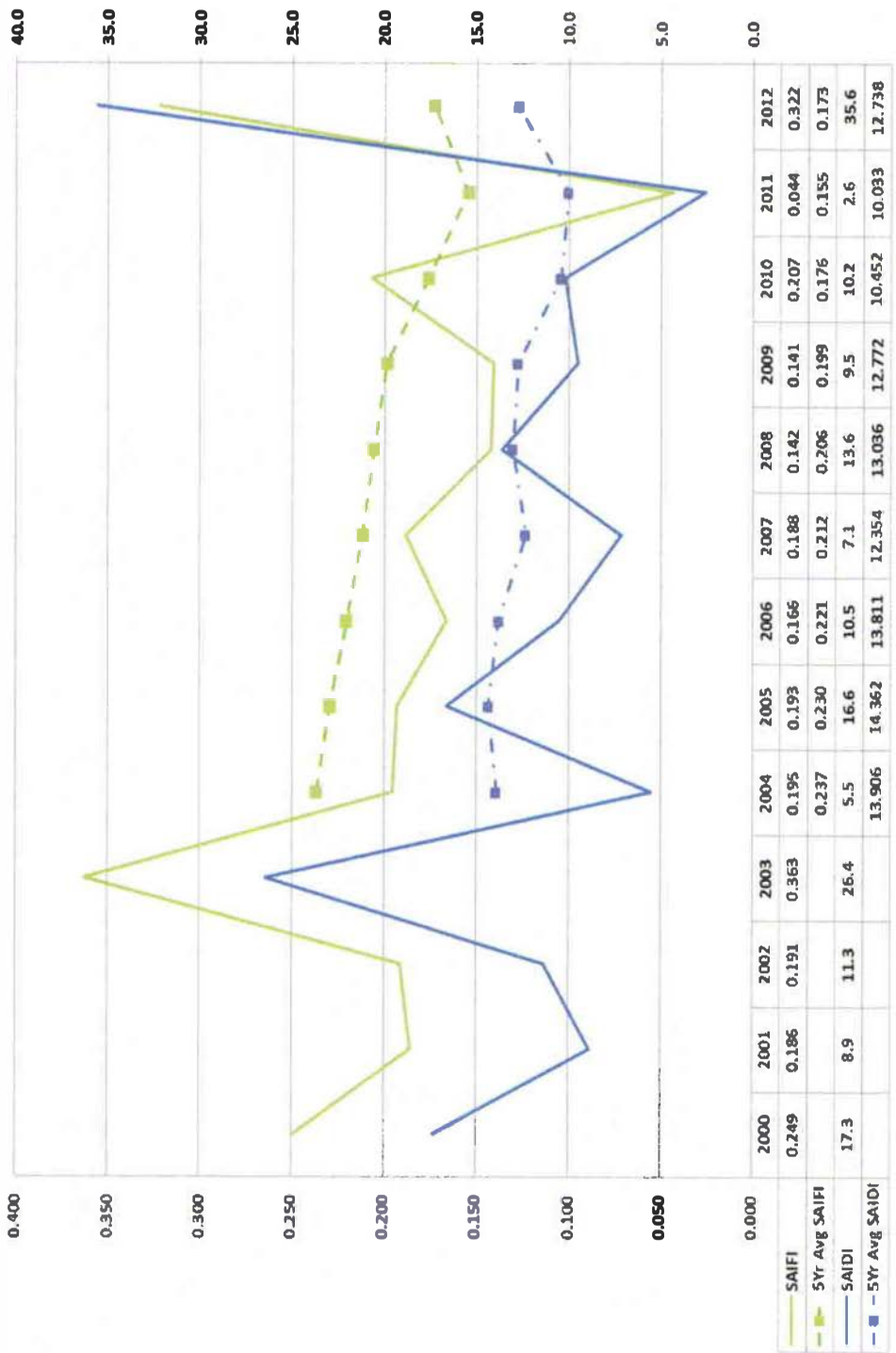
Gulf Power Transmission Reliability History



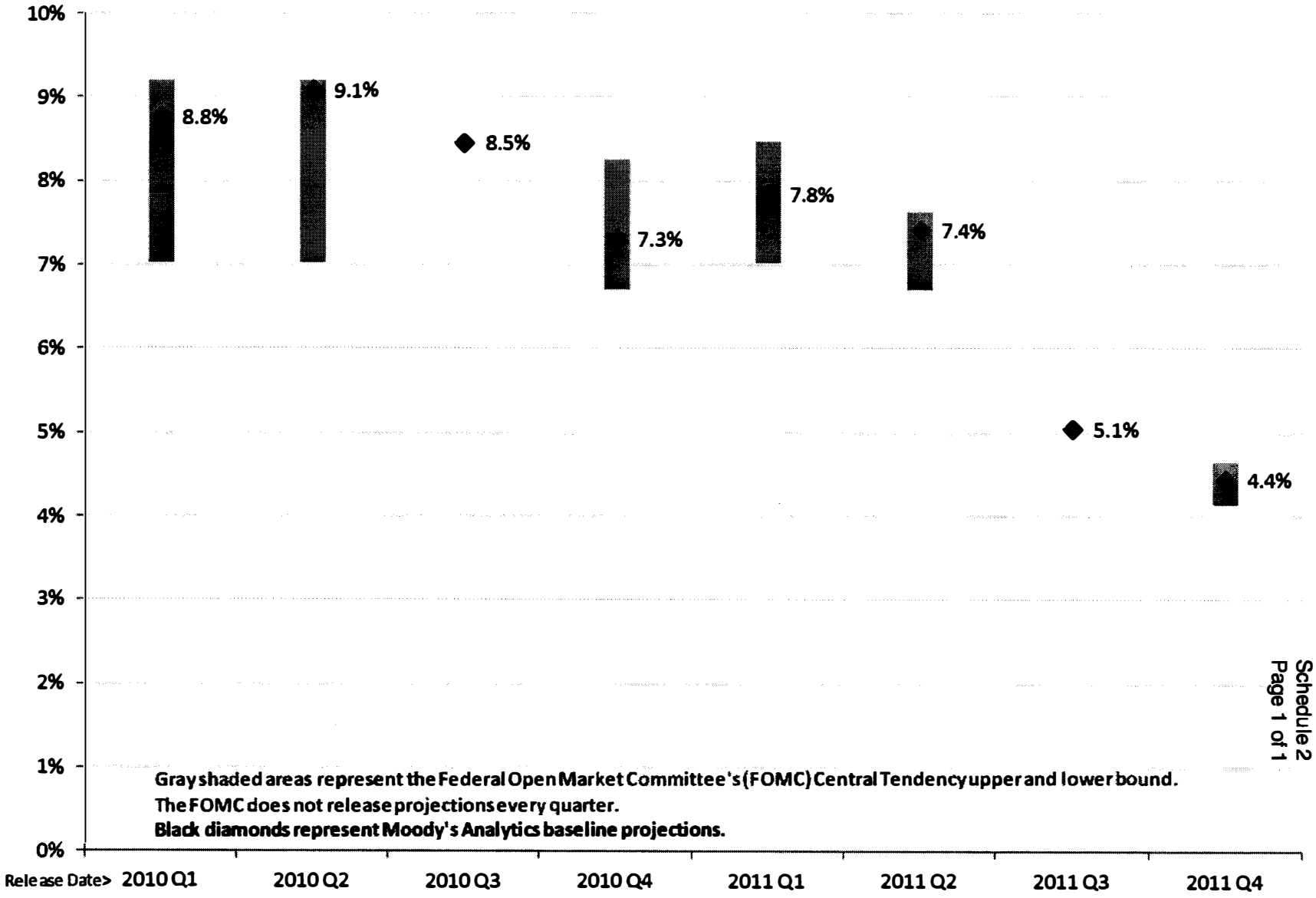
	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
SAIFI	0.249	0.186	0.191	0.363	0.195	0.193	0.166	0.188	0.142	0.141	0.207	0.044	0.322
5Yr Avg SAIFI					0.237	0.230	0.221	0.212	0.206	0.199	0.176	0.155	0.173
SAIDI	17.3	8.9	11.3	26.4	5.5	16.6	10.5	7.1	13.6	9.5	10.2	2.6	35.6
5Yr Avg SAIDI					13.906	14.362	13.811	12.354	13.036	12.772	10.452	10.033	12.738

Responsibility for Minimum Filing Requirements

Schedule	Title
C-34	Statistical Information
E-15	Projected Billing Determinants – Derivation
E-18	Monthly Peaks
F-5	Forecasting Models
F-6	Forecasting Models – Sensitivity of Output to Changes in Input Data
F-7	Forecasting Models – Historical Data
F-8	Assumptions

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130140-EI EXHIBIT 12
PARTY Gulf Power Company (Gulf) Direct
DESCRIPTION Rhonda Alexander (RJA-1)

Forecast 2011 & 2012 Cumulative Annual Growth in U.S. Real GDP



Gray shaded areas represent the Federal Open Market Committee's (FOMC) Central Tendency upper and lower bound.
The FOMC does not release projections every quarter.
Black diamonds represent Moody's Analytics baseline projections.

Florida Public Service Commission
Docket No. 130140-EI
GULF POWER COMPANY
Witness: Rhonda J. Alexander
Exhibit No. ____ (RJA-1)
Schedule 2
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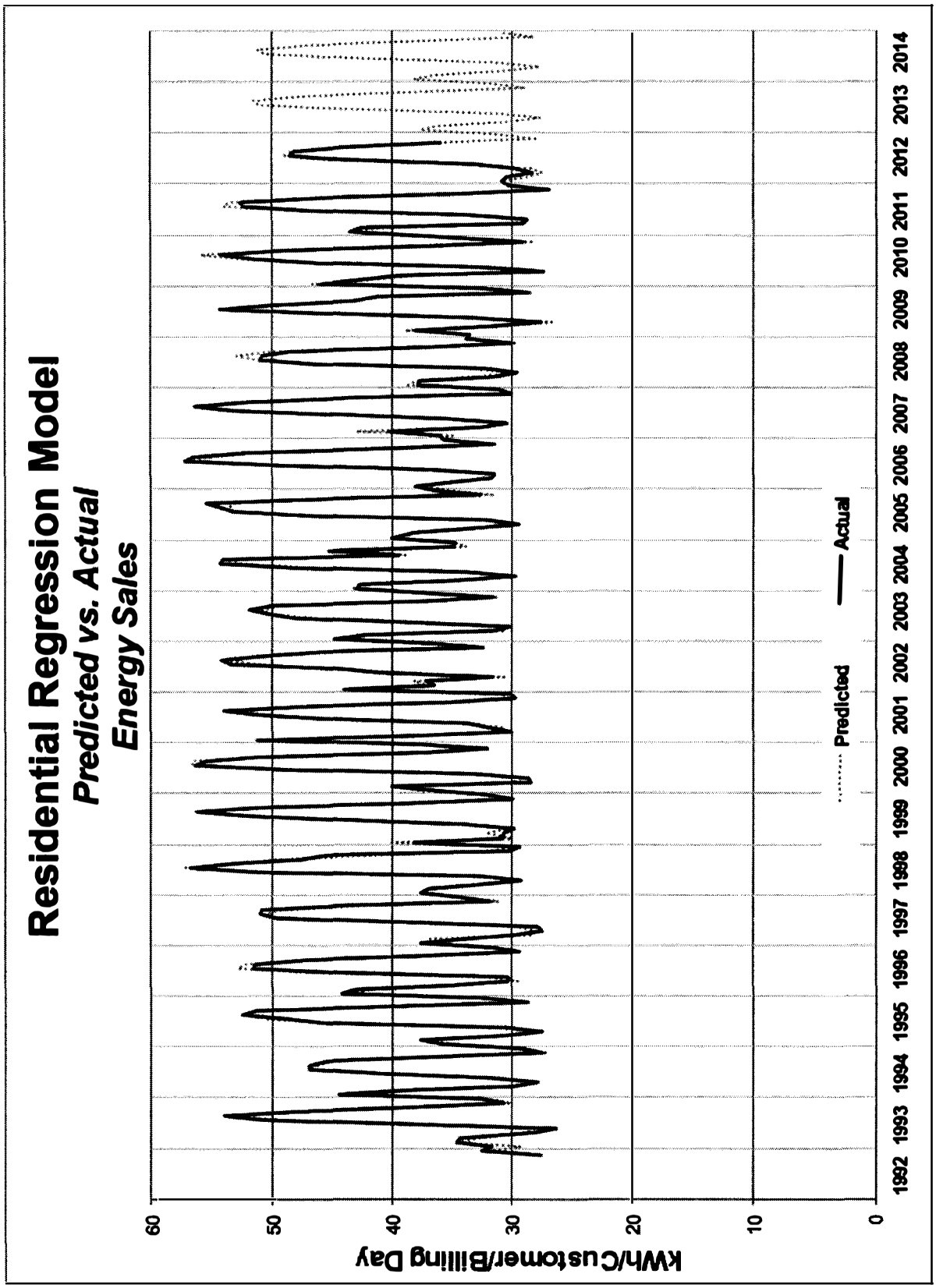


Residential Regression Model Summary

Software:	MetrixND Version 4.4
Dependent Variable:	Monthly Billing Cycle Residential kWh per Customer per Billing Day
Estimation Dates:	November 1992-October 2012

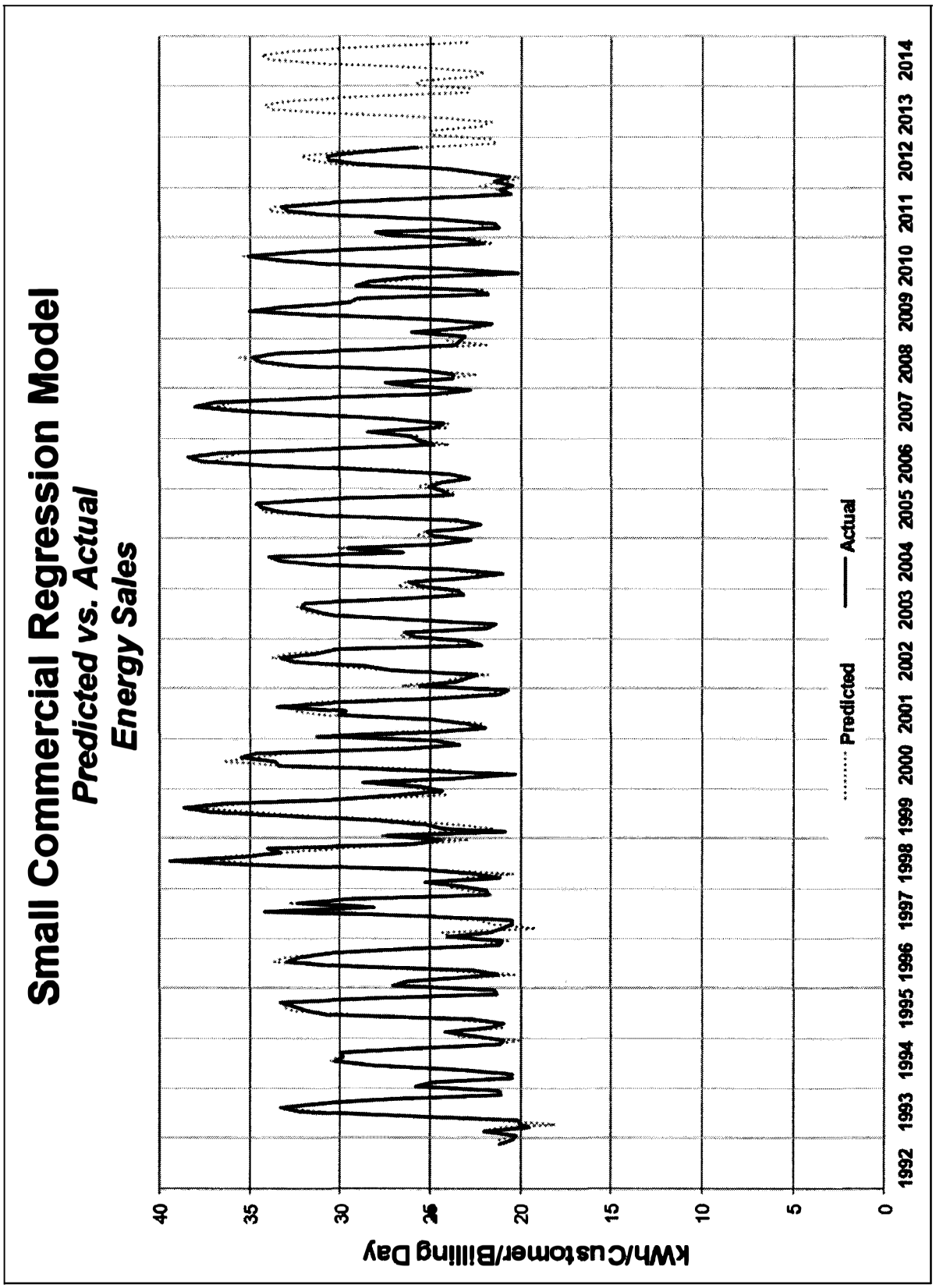
Residential Regression Statistics

Iterations	12
Adjusted Observations	239
Deg. of Freedom for Error	215
R-Squared	0.986
Adjusted R-Squared	0.985
Durbin-Watson Statistic	2.090
Standard Error of Regression	1.07
Mean Absolute Percentage Error (MAPE)	2.07%
Skewness	0.178
Kurtosis	3.762

Residential Regression Model Coefficients

Variable	Coefficient	Standard Error	p-Value	Mean	Elasticity
Constant	27.548	5.384	0.00%	N/A	N/A
Real Disposable Personal Income per Household	0.263	0.054	0.00%	67.397	0.449
12-Month Average of Real Residential Price - Decline Index	-0.700	0.403	8.36%	6.984	-0.124
12-Month Average of Real Residential Price - Increase Index	-1.532	0.153	0.00%	10.993	-0.426
Billing Cycle Residential CDH per Billing Day - March	0.047	0.017	0.55%	1.592	0.002
Billing Cycle Residential CDH per Billing Day - April	0.058	0.008	0.00%	4.504	0.007
Billing Cycle Residential CDH per Billing Day - May	0.070	0.004	0.00%	11.567	0.020
Billing Cycle Residential CDH per Billing Day - June	0.080	0.002	0.00%	22.892	0.046
Billing Cycle Residential CDH per Billing Day - July	0.082	0.001	0.00%	29.050	0.061
Billing Cycle Residential CDH per Billing Day - August	0.084	0.001	0.00%	29.500	0.062
Billing Cycle Residential CDH per Billing Day - September	0.079	0.002	0.00%	26.842	0.054
Billing Cycle Residential CDH per Billing Day - October	0.080	0.002	0.00%	17.042	0.034
Billing Cycle Residential CDH per Billing Day - November	0.055	0.007	0.00%	6.350	0.009
Billing Cycle Residential CDH per Billing Day - December	0.060	0.016	0.02%	1.796	0.003
Billing Cycle Residential HDH per Billing Day - January	0.078	0.002	0.00%	17.117	0.034
Billing Cycle Residential HDH per Billing Day - February	0.077	0.002	0.00%	15.667	0.030
Billing Cycle Residential HDH per Billing Day - March	0.071	0.004	0.00%	8.954	0.016
Billing Cycle Residential HDH per Billing Day - April	0.070	0.010	0.00%	3.254	0.006
Billing Cycle Residential HDH per Billing Day - November	0.057	0.010	0.00%	3.721	0.005
Billing Cycle Residential HDH per Billing Day - December	0.064	0.003	0.00%	10.963	0.018
Binary Variable for Hurricane Ivan September 2004	-9.998	1.004	0.00%	0.004	-0.001
Binary Variable for June-August 2008	-3.787	0.836	0.00%	0.013	-0.001
Binary Variable for Hurricane Isaac August-September 2012	-2.234	0.906	1.45%	0.008	-0.000
First Order Auto-Regressive Term, AR(1)	0.435	0.062	0.00%	N/A	N/A

HDH = Heating Degree Hours
CDH = Cooling Degree Hours


Small Commercial Regression Model
Predicted vs. Actual
Energy Sales
kWh/Customer/Billing Day
0
5
10
15
20
25
30
35
40
1992
1993
1994
1995
1996
1997
1998
1999
2000
2001
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
Predicted
Actual

Small Commercial Regression Model Summary

Software:	MetrixND Version 4.4
Dependent Variable:	Monthly Billing Cycle Small Commercial kWh per Customer per Billing Day
Estimation Dates:	November 1992-October 2012

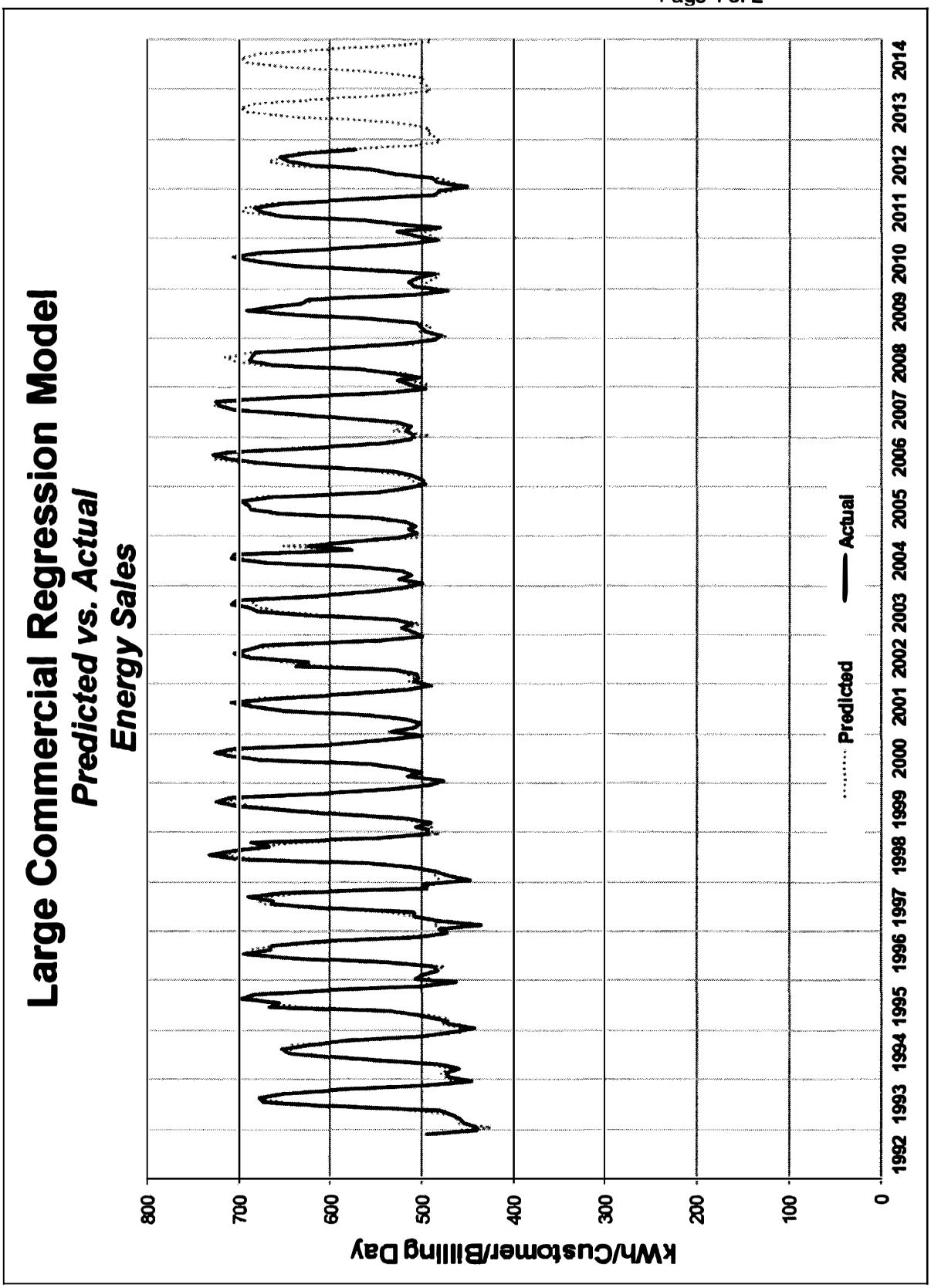
Small Commercial Regression Statistics

Iterations	8
Adjusted Observations	239
Deg. of Freedom for Error	221
R-Squared	0.953
Adjusted R-Squared	0.949
Durbin-Watson Statistic	2.271
Standard Error of Regression	1.09
Mean Absolute Percentage Error (MAPE)	2.94%
Skewness	0.336
Kurtosis	4.476

Small Commercial Regression Model Coefficients

Variable	Coefficient	Standard Error	p-Value	Mean	Elasticity
Constant	14.286	2.102	0.00%	N/A	N/A
Non-Manufacturing Employment	0.040	0.008	0.00%	281.479	0.413
12-Month Average of Real Commercial Price	-0.711	0.159	0.00%	7.392	-0.195
Billing Cycle Small Commercial CDH per Billing Day - April	0.030	0.006	0.00%	4.504	0.005
Billing Cycle Small Commercial CDH per Billing Day - May	0.032	0.003	0.00%	11.567	0.014
Billing Cycle Small Commercial CDH per Billing Day - June	0.038	0.001	0.00%	22.892	0.032
Billing Cycle Small Commercial CDH per Billing Day - July	0.038	0.001	0.00%	29.050	0.041
Billing Cycle Small Commercial CDH per Billing Day - August	0.039	0.001	0.00%	29.500	0.043
Billing Cycle Small Commercial CDH per Billing Day - September	0.038	0.001	0.00%	26.842	0.038
Billing Cycle Small Commercial CDH per Billing Day - October	0.040	0.002	0.00%	17.042	0.025
Billing Cycle Small Commercial CDH per Billing Day - November	0.033	0.005	0.00%	6.350	0.008
Billing Cycle Small Commercial HDH per Billing Day - January	0.026	0.002	0.00%	17.117	0.017
Billing Cycle Small Commercial HDH per Billing Day - February	0.028	0.002	0.00%	15.667	0.016
Billing Cycle Small Commercial HDH per Billing Day - March	0.021	0.003	0.00%	8.954	0.007
Billing Cycle Small Commercial HDH per Billing Day - December	0.018	0.003	0.00%	10.963	0.008
Binary Variable for Hurricane Ivan September 2004	-5.477	0.953	0.00%	0.004	-0.001
Binary Variable for August 1997	-5.400	0.956	0.00%	0.004	-0.001
First Order Auto-Regressive Term, AR(1)	0.607	0.054	0.00%	N/A	N/A

HDH = Heating Degree Hours
CDH = Cooling Degree Hours


Large Commercial Regression Model
Predicted vs. Actual
Energy Sales
kWh/Customer/Billing Day
800
700
600
500
400
300
200
100
0
1992 1993 1994 1995 1996 1997 1998 1999 2000 2001 2002 2003 2004 2005 2006 2007 2008 2009 2010 2011 2012 2013 2014
Predicted
Actual

Large Commercial Regression Model Summary

Software:	MetrixND Version 4.4
Dependent Variable:	Monthly Billing Cycle Large Commercial kWh per Customer per Billing Day
Estimation Dates:	November 1992-October 2012

Large Commercial Regression Statistics

Iterations	12
Adjusted Observations	239
Deg. of Freedom for Error	218
R-Squared	0.976
Adjusted R-Squared	0.974
Durbin-Watson Statistic	2.025
Standard Error of Regression	13.67
Mean Absolute Percentage Error (MAPE)	1.75%
Skewness	0.057
Kurtosis	4.509

Large Commercial Regression Model Coefficients

Variable	Coefficient	Standard Error	p-Value	Mean	Elasticity
Constant	381.984	12.661	0.00%	N/A	N/A
Non-Manufacturing Employment	0.620	0.045	0.00%	281.479	0.304
12-Month Average of Real Commercial Price	-11.603	0.952	0.00%	7.392	-0.150
Billing Cycle Large Commercial CDH per Billing Day - March	0.219	0.100	3.01%	3.825	0.001
Billing Cycle Large Commercial CDH per Billing Day - April	0.395	0.051	0.00%	8.696	0.006
Billing Cycle Large Commercial CDH per Billing Day - May	0.435	0.026	0.00%	17.967	0.014
Billing Cycle Large Commercial CDH per Billing Day - June	0.481	0.015	0.00%	30.667	0.026
Billing Cycle Large Commercial CDH per Billing Day - July	0.487	0.013	0.00%	37.046	0.031
Billing Cycle Large Commercial CDH per Billing Day - August	0.498	0.013	0.00%	37.496	0.033
Billing Cycle Large Commercial CDH per Billing Day - September	0.496	0.014	0.00%	34.792	0.030
Billing Cycle Large Commercial CDH per Billing Day - October	0.505	0.020	0.00%	23.996	0.021
Billing Cycle Large Commercial CDH per Billing Day - November	0.418	0.043	0.00%	10.638	0.008
Billing Cycle Large Commercial HDH per Billing Day - January	0.320	0.056	0.00%	11.142	0.006
Billing Cycle Large Commercial HDH per Billing Day - February	0.241	0.045	0.00%	9.754	0.004
Billing Cycle Large Commercial HDH per Billing Day - March	0.215	0.071	0.27%	4.975	0.002
Billing Cycle Large Commercial HDH per Billing Day - December	0.211	0.067	0.17%	6.313	0.002
Binary Variable for Hurricane Ivan September 2004	-101.991	13.827	0.00%	0.004	-0.001
Binary Variable for Hurricanes Dennis and Katrina July-September 2005	-19.883	9.087	2.97%	0.013	-0.000
Binary Variable for Hurricane Isaac August-September 2012	-28.325	10.774	0.92%	0.008	-0.000
Monthly Binary Variable for January	-24.570	9.041	0.71%	0.083	-0.004
First Order Auto-Regressive Term, AR(1)	0.157	0.068	2.27%	N/A	N/A

HDH = Heating Degree Hours
CDH = Cooling Degree Hours

Responsibility for Minimum Filing Requirements

Schedule	Title
A-1	Full Revenue Requirements Increase Requested
C-24	Parent(s) Debt Information
D-2	Cost of Capital – 5 Year History
D-3	Short-Term Debt
D-7	Common Stock Data
D-8	Financing Plans – Stock and Bond Issues
D-9	Financial Indicators – Summary
F-1	Annual and Quarterly Reports to Shareholders
F-2	SEC Reports
F-3	Business Contracts with Officers or Directors
F-8	Assumptions
F-9	Public Notice

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Schedule 2
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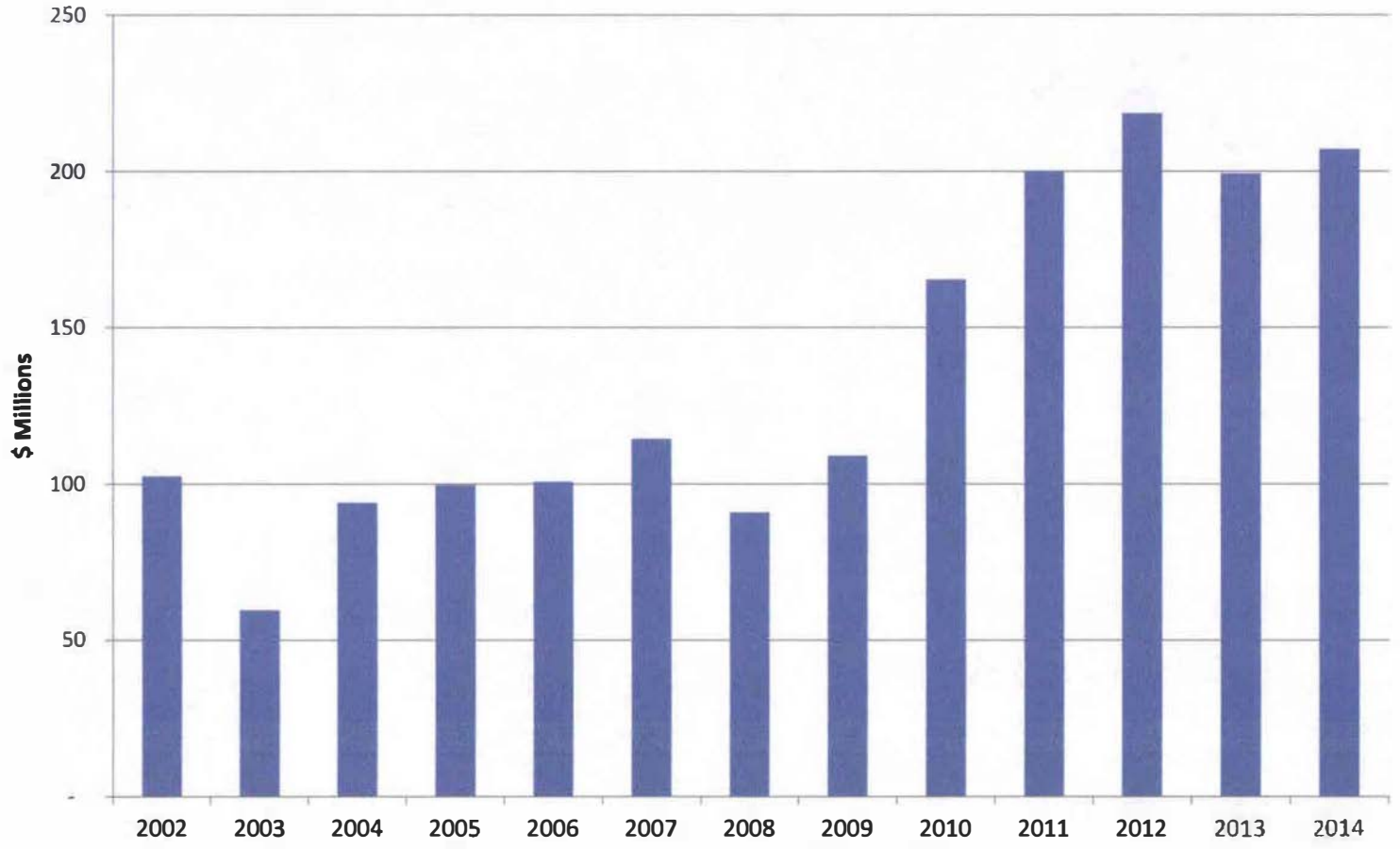
Base Rate Capital Expenditures *

(actuals through 2012)



* Capital expenditures shown on graph do not include wholesale, clauses and non-utility

Florida Public Service Commission
Docket No. 130140-EI
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Witness: R. Scott Teel
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GULF POWER COMPANY
Witness: R. Scott Teel
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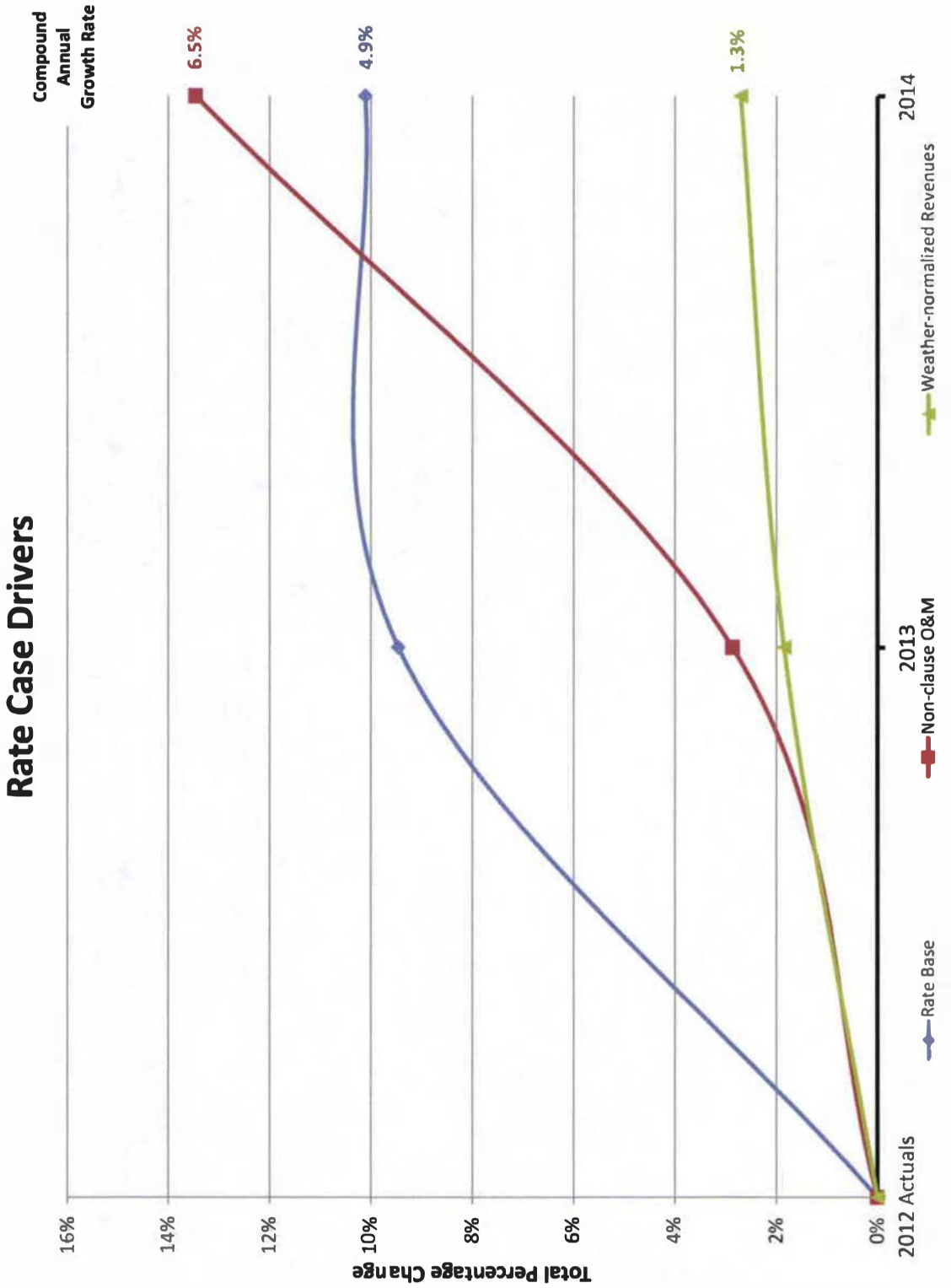

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GULF POWER COMPANY
Witness: R. Scott Teel
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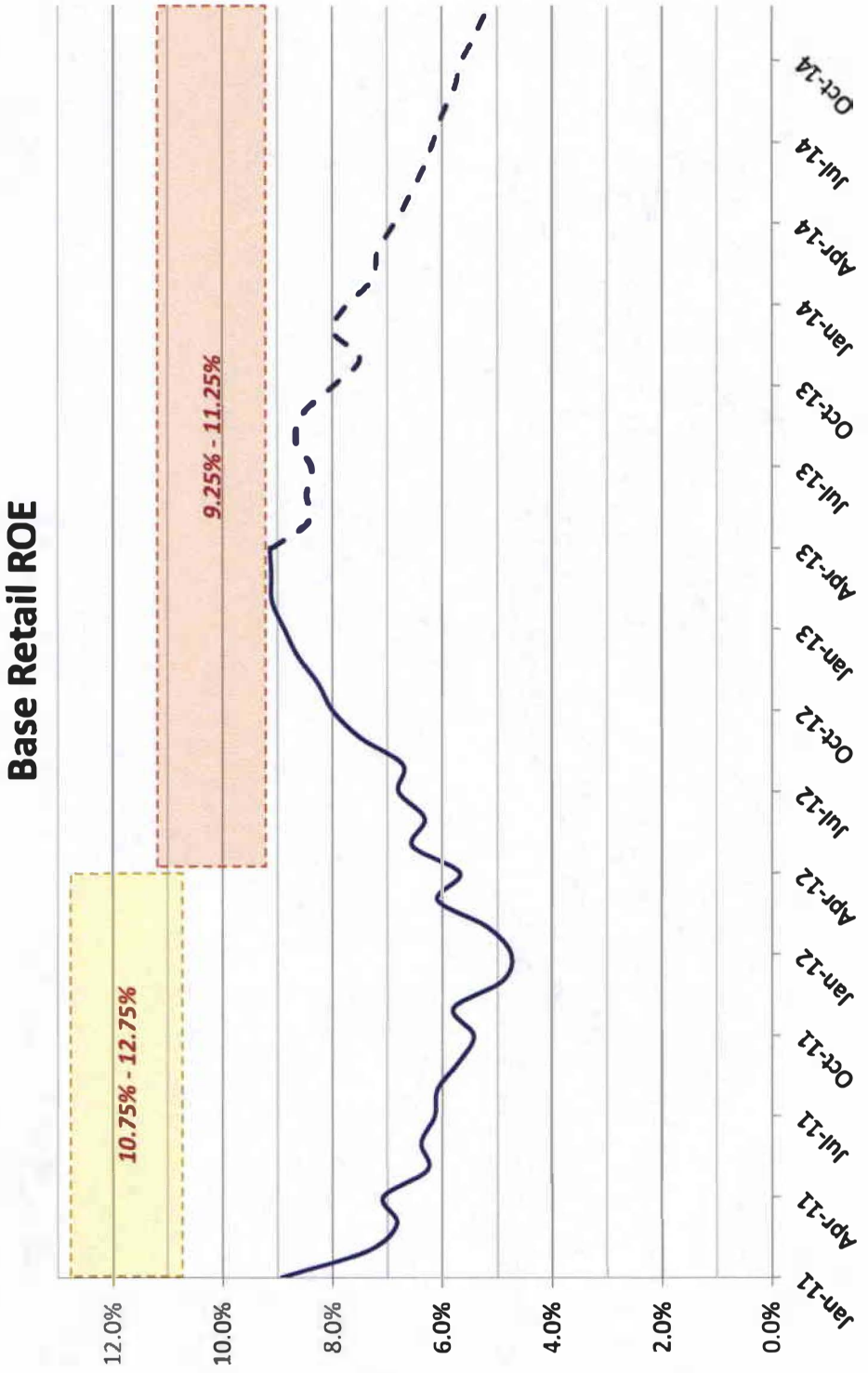
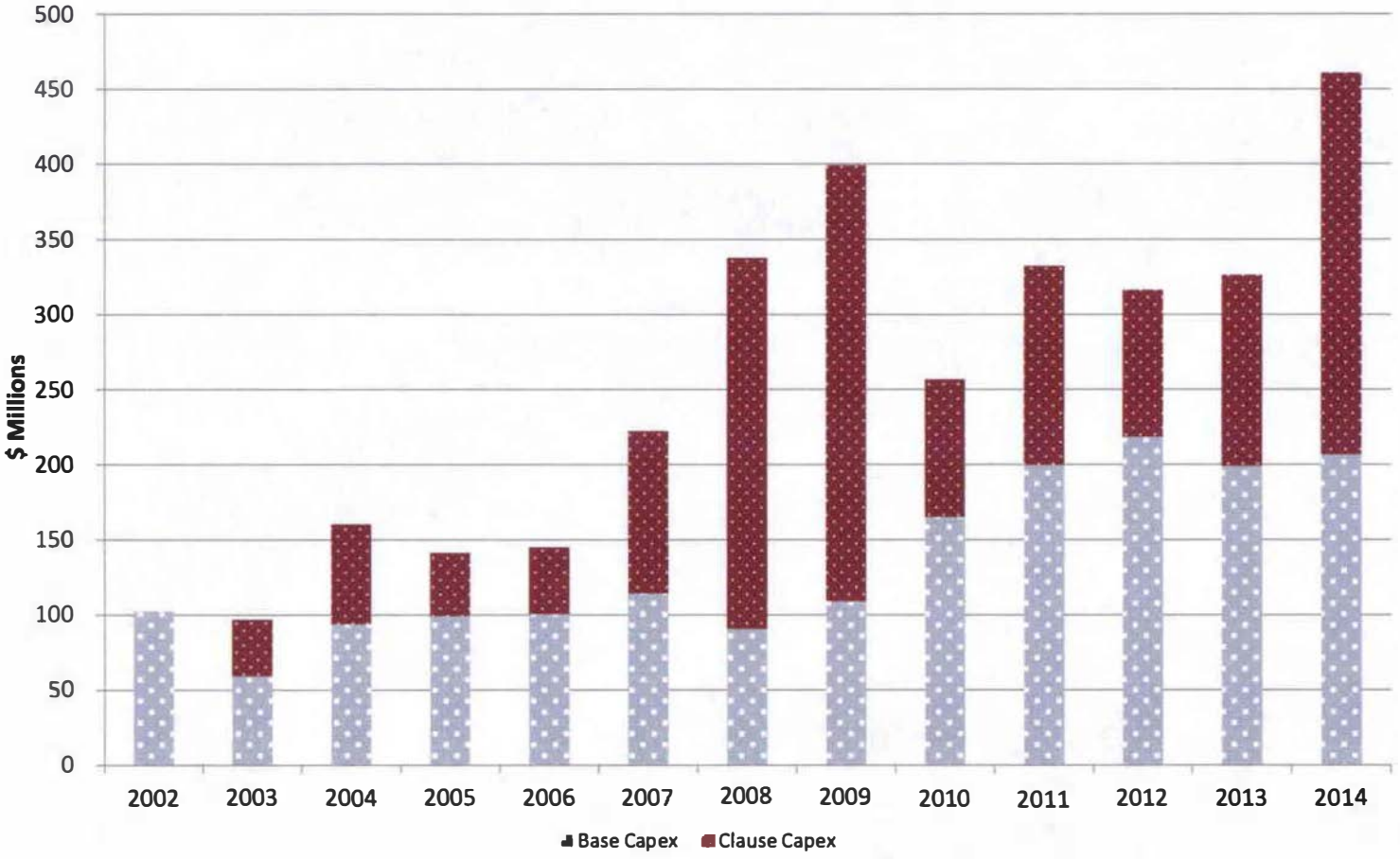


Total Retail Capital Expenditures *

(actuals through 2012)

(Base + Clause)



* Capital expenditures shown on graph do not include wholesale or non-utility

Florida Public Service Commission
Docket No. 130140-EI
GULF POWER COMPANY
Witness: R. Scott Teel
Exhibit No. _____ (RST-1)
Schedule 6
Page 1 of 1

PARENT DEBT ADJUSTMENT RULE 25-14.004

25-14.004 Effect of Parent Debt on Federal Corporate Income Tax.

In Commission proceedings to establish revenue requirements or address over-earnings, other than those entered into under Rule 25-14.003, F.A.C., the income tax expense of a regulated company shall be adjusted to reflect the income tax expense of the parent debt that may be invested in the equity of the subsidiary where a parent-subsidiary relationship exists and the parties to the relationship join in the filing of a consolidated income tax return.

(1) Where the regulated utility is a subsidiary of a single parent, the income tax effect of the parent's debt invested in the equity of the subsidiary utility shall reduce the income tax expense of the utility.

(2) Where the regulated utility is a subsidiary of tiered parents, the adjusted income tax effect of the debt of all parents invested in the equity of the subsidiary utility shall reduce the income tax expense of the utility.

(3) The capital structure of the parent used to make the adjustment shall include at least long term debt, short term debt, common stock, cost free capital and investment tax credits, excluding retained earnings of the subsidiaries. It shall be a rebuttable presumption that a parent's investment in any subsidiary or in its own operations shall be considered to have been made in the same ratios as exist in the parent's overall capital structure.

(4) The adjustment shall be made by multiplying the debt ratio of the parent by the debt cost of the parent. This product shall be multiplied by the statutory tax rate applicable to the consolidated entity. This result shall be multiplied by the equity dollars of the subsidiary, excluding its retained earnings. The resulting dollar amount shall be used to adjust the income tax expense of the utility.

Specific Authority 350.127(2) FS. Law Implemented 366.05(1), 364.03, 364.035, 367.121(1)(a) FS. History–New 1-25-83, Formerly 25-14.04.

Gulf Dividends Compared To Southern Company Capital Contributions 2011 - 2014 ($0000)

Year	Gulf Dividends to Southern	Gulf Equity from Southern	Net Cash To (From) Southern
2011	110,000	50,000	60,000
2012	115,800	40,000	75,800
1Q & 2Q - 2013	57,700	40,000	17,700
Subtotal	283,500	130,000	153,500
3Q & 4Q - 2013 Projection	57,700	-	57,700
2014 Projection	120,560	120,798	(238)
Subtotal	178,260	120,798	57,462
Total	**461,760**	**250,798**	**210,962**

Note: Equity contributions typically occur during 1st quarter of each year.

Florida Public Service Commission
Docket No. 130140-EI
GULF POWER COMPANY
Witness: James H. Vander Weide, Ph.D.
Exhibit No. _____ (JVW-1)

LIST OF SCHEDULES AND APPENDICES

Exhibit JVW-1 Schedule 1 Summary of Discounted Cash Flow Analysis for Electric Utilities

Exhibit JVW-1 Schedule 2 Comparison of the DCF Expected Return on an Investment in Electric Utilities to the Interest Rate on Moody's A-Rated Utility Bonds

Exhibit JVW-1 Schedule 3 Comparative Returns on S&P 500 Stock Index and Moody's A-Rated Bonds 1937—2013

Exhibit JVW-1 Schedule 4 Comparative Returns on S&P Utility Stock Index and Moody's A-Rated Bonds 1937—2013

Exhibit JVW-1 Schedule 5 Using the Arithmetic Mean to Estimate the Cost of Equity Capital

Exhibit JVW-1 Schedule 6 Calculation of Capital Asset Pricing Model Cost of Equity Using the Ibbottson SBBI 6.7 Percent Risk Premium

Exhibit JVW-1 Schedule 7 Comparison of Risk Premiums on S&P500 and S&P Utilities 1937 – 2013

Exhibit JVW-1 Schedule 8 Calculation of Capital Asset Pricing Model Cost of Equity Using DCF Estimate of the Expected Rate of Return on the Market Portfolio

Exhibit JVW-1 Schedule 9 Illustration of Calculation of Cost of Equity Required for the Company to Have the Same Weighted Average Cost of Capital as Comparable Electric Utilities

Exhibit JVW-2 Appendix 1 Qualifications of James H. Vander Weide

Exhibit JVW-2 Appendix 2 Derivation of the Quarterly DCF Model

Exhibit JVW-2 Appendix 3 Adjusting for Flotation Costs in Determining a Public Utility's Allowed Rate of Return on Equity

Exhibit JVW-2 Appendix 4 Ex Ante Risk Premium Method

Exhibit JVW-2 Appendix 5 Ex Post Risk Premium Method

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130140-EI EXHIBIT 14
PARTY Gulf Power Company (Gulf) Direct
DESCRIPTION James Vander Weide (JVW-1)

EXHIBIT JVW-1 SCHEDULE 1
SUMMARY OF DISCOUNTED CASH FLOW ANALYSIS
FOR ELECTRIC UTILITIES

LINE	COMPANY	D_0	P_0	GROWTH	MODEL RESULT
1	ALLETE	0.475	43.442	6.00%	11.0%
2	Alliant Energy	0.470	45.377	5.80%	10.4%
3	Amer. Elec. Power	0.470	44.257	4.46%	9.3%
4	Black Hills	0.380	38.603	6.00%	10.5%
5	CenterPoint Energy	0.207	20.123	5.30%	10.0%
6	CMS Energy Corp.	0.255	25.223	6.06%	10.5%
7	Dominion Resources	0.563	53.385	7.27%	12.0%
8	DTE Energy	0.620	62.506	4.58%	9.0%
9	Duke Energy	0.765	66.616	3.77%	8.9%
10	Entergy Corp.	0.830	63.632	2.50%	8.3%
11	G't Plains Energy	0.217	21.041	7.57%	12.4%
12	Hawaiian Elec.	0.310	26.198	6.70%	12.3%
13	Integrys Energy	0.680	54.274	5.50%	11.3%
14	NextEra Energy	0.660	71.090	6.37%	10.4%
15	Northeast Utilities	0.367	40.061	6.58%	10.6%
16	NorthWestern Corp.	0.370	36.314	5.00%	9.7%
17	OGE Energy	0.417	57.380	5.10%	8.3%
18	Otter Tail Corp.	0.298	26.274	5.00%	10.2%
19	Pepco Holdings	0.270	19.677	4.25%	10.5%
20	Pinnacle West Capital	0.545	52.777	7.50%	12.3%
21	PNM Resources	0.145	21.108	8.53%	11.8%
22	Portland General	0.270	28.150	5.58%	10.0%
23	SCANA Corp.	0.507	46.753	5.40%	10.3%
24	Sempra Energy	0.600	73.383	7.00%	10.8%
25	Southern Co.	0.490	43.770	4.83%	10.0%
26	TECO Energy	0.220	17.113	3.02%	8.8%
27	Vectren Corp.	0.355	30.828	5.00%	10.2%
28	Westar Energy	0.340	29.622	7.50%	12.8%
29	Wisconsin Energy	0.340	38.572	5.37%	9.1%
30	Xcel Energy Inc.	0.270	27.455	4.95%	9.4%
31	Average				10.4%

Notes:

d_0	=	Most recent quarterly dividend.
d_1, d_2, d_3, d_4	=	Next four quarterly dividends, calculated by multiplying the last four quarterly dividends per Value Line by the factor (1 + g).
P_0	=	Average of the monthly high and low stock prices during the three months ending February 2013 per Thomson Reuters.
FC	=	Flotation cost allowance (5%) as a percent of stock price.
g	=	I/B/E/S forecast of future earnings growth February 2013 from Thomson Reuters.
k	=	Cost of equity using the quarterly version of the DCF model.

$$k = \frac{d_1(1+k)^{.75} + d_2(1+k)^{.50} + d_3(1+k)^{.25} + d_4}{P_0(1-FC)} + g$$

EXHIBIT JVW-1 SCHEDULE 2
COMPARISON OF DCF EXPECTED RETURN ON AN INVESTMENT IN ELECTRIC UTILITIES TO THE INTEREST RATE ON MOODY'S A-RATED UTILITY BONDS

Line	Date	DCF	Bond Yield	Risk Premium
1	Sep-99	0.1157	0.0793	0.0364
2	Oct-99	0.1161	0.0806	0.0355
3	Nov-99	0.1192	0.0794	0.0398
4	Dec-99	0.1236	0.0814	0.0422
5	Jan-00	0.1221	0.0835	0.0386
6	Feb-00	0.1269	0.0825	0.0444
7	Mar-00	0.1313	0.0828	0.0485
8	Apr-00	0.1237	0.0829	0.0408
9	May-00	0.1227	0.0870	0.0357
10	Jun-00	0.1242	0.0836	0.0406
11	Jul-00	0.1247	0.0825	0.0422
12	Aug-00	0.1228	0.0813	0.0415
13	Sep-00	0.1164	0.0823	0.0341
14	Oct-00	0.1170	0.0814	0.0356
15	Nov-00	0.1191	0.0811	0.0380
16	Dec-00	0.1166	0.0784	0.0382
17	Jan-01	0.1194	0.0780	0.0414
18	Feb-01	0.1203	0.0774	0.0429
19	Mar-01	0.1207	0.0768	0.0439
20	Apr-01	0.1233	0.0794	0.0439
21	May-01	0.1279	0.0799	0.0480
22	Jun-01	0.1285	0.0785	0.0500
23	Jul-01	0.1295	0.0778	0.0517
24	Aug-01	0.1302	0.0759	0.0543
25	Sep-01	0.1321	0.0775	0.0546
26	Oct-01	0.1313	0.0763	0.0550
27	Nov-01	0.1296	0.0757	0.0539
28	Dec-01	0.1292	0.0783	0.0509
29	Jan-02	0.1274	0.0766	0.0508
30	Feb-02	0.1285	0.0754	0.0531
31	Mar-02	0.1248	0.0776	0.0472
32	Apr-02	0.1227	0.0757	0.0470
33	May-02	0.1236	0.0752	0.0484

Line	Date	DCF	Bond Yield	Risk Premium
34	Jun-02	0.1254	0.0741	0.0513
35	Jul-02	0.1337	0.0731	0.0606
36	Aug-02	0.1300	0.0717	0.0583
37	Sep-02	0.1272	0.0708	0.0564
38	Oct-02	0.1291	0.0723	0.0568
39	Nov-02	0.1242	0.0714	0.0528
40	Dec-02	0.1226	0.0707	0.0519
41	Jan-03	0.1195	0.0706	0.0489
42	Feb-03	0.1233	0.0693	0.0540
43	Mar-03	0.1212	0.0679	0.0533
44	Apr-03	0.1170	0.0664	0.0506
45	May-03	0.1095	0.0636	0.0459
46	Jun-03	0.1047	0.0621	0.0426
47	Jul-03	0.1072	0.0657	0.0415
48	Aug-03	0.1064	0.0678	0.0386
49	Sep-03	0.1029	0.0656	0.0373
50	Oct-03	0.1009	0.0643	0.0366
51	Nov-03	0.0985	0.0637	0.0348
52	Dec-03	0.0946	0.0627	0.0319
53	Jan-04	0.0921	0.0615	0.0306
54	Feb-04	0.0916	0.0615	0.0301
55	Mar-04	0.0912	0.0597	0.0315
56	Apr-04	0.0925	0.0635	0.0290
57	May-04	0.0962	0.0662	0.0300
58	Jun-04	0.0961	0.0646	0.0315
59	Jul-04	0.0953	0.0627	0.0326
60	Aug-04	0.0966	0.0614	0.0352
61	Sep-04	0.0951	0.0598	0.0353
62	Oct-04	0.0953	0.0594	0.0359
63	Nov-04	0.0918	0.0597	0.0321
64	Dec-04	0.0920	0.0592	0.0328
65	Jan-05	0.0925	0.0578	0.0347
66	Feb-05	0.0917	0.0561	0.0356
67	Mar-05	0.0918	0.0583	0.0335
68	Apr-05	0.0924	0.0564	0.0360
69	May-05	0.0910	0.0553	0.0356
70	Jun-05	0.0911	0.0540	0.0371
71	Jul-05	0.0899	0.0551	0.0348

Line	Date	DCF	Bond Yield	Risk Premium
72	Aug-05	0.0900	0.0550	0.0350
73	Sep-05	0.0923	0.0552	0.0371
74	Oct-05	0.0934	0.0579	0.0355
75	Nov-05	0.0981	0.0588	0.0393
76	Dec-05	0.0980	0.0580	0.0400
77	Jan-06	0.0980	0.0575	0.0405
78	Feb-06	0.1071	0.0582	0.0489
79	Mar-06	0.1055	0.0598	0.0457
80	Apr-06	0.1075	0.0629	0.0446
81	May-06	0.1087	0.0642	0.0445
82	Jun-06	0.1117	0.0640	0.0477
83	Jul-06	0.1110	0.0637	0.0473
84	Aug-06	0.1072	0.0620	0.0452
85	Sep-06	0.1111	0.0600	0.0511
86	Oct-06	0.1074	0.0598	0.0476
87	Nov-06	0.1078	0.0580	0.0498
88	Dec-06	0.1071	0.0581	0.0490
89	Jan-07	0.1096	0.0596	0.0500
90	Feb-07	0.1085	0.0590	0.0495
91	Mar-07	0.1094	0.0585	0.0509
92	Apr-07	0.1042	0.0597	0.0445
93	May-07	0.1068	0.0599	0.0469
94	Jun-07	0.1123	0.0630	0.0493
95	Jul-07	0.1130	0.0625	0.0505
96	Aug-07	0.1104	0.0624	0.0480
97	Sep-07	0.1078	0.0618	0.0460
98	Oct-07	0.1084	0.0611	0.0473
99	Nov-07	0.1116	0.0597	0.0519
100	Dec-07	0.1132	0.0616	0.0516
101	Jan-08	0.1193	0.0602	0.0591
102	Feb-08	0.1133	0.0621	0.0512
103	Mar-08	0.1170	0.0621	0.0549
104	Apr-08	0.1159	0.0629	0.0530
105	May-08	0.1162	0.0627	0.0535
106	Jun-08	0.1136	0.0638	0.0499
107	Jul-08	0.1172	0.0640	0.0532
108	Aug-08	0.1191	0.0637	0.0554
109	Sep-08	0.1185	0.0649	0.0536

Line	Date	DCF	Bond Yield	Risk Premium
110	Oct-08	0.1280	0.0756	0.0524
111	Nov-08	0.1312	0.0760	0.0552
112	Dec-08	0.1301	0.0654	0.0647
113	Jan-09	0.1241	0.0639	0.0602
114	Feb-09	0.1269	0.0630	0.0639
115	Mar-09	0.1286	0.0642	0.0644
116	Apr-09	0.1266	0.0648	0.0617
117	May-09	0.1242	0.0649	0.0593
118	Jun-09	0.1220	0.0620	0.0600
119	Jul-09	0.1174	0.0597	0.0577
120	Aug-09	0.1158	0.0571	0.0587
121	Sep-09	0.1152	0.0553	0.0599
122	Oct-09	0.1153	0.0555	0.0598
123	Nov-09	0.1196	0.0564	0.0633
124	Dec-09	0.1095	0.0579	0.0516
125	Jan-10	0.1112	0.0577	0.0535
126	Feb-10	0.1091	0.0587	0.0504
127	Mar-10	0.1076	0.0584	0.0492
128	Apr-10	0.1111	0.0582	0.0529
129	May-10	0.1093	0.0552	0.0541
130	Jun-10	0.1088	0.0546	0.0541
131	Jul-10	0.1078	0.0526	0.0552
132	Aug-10	0.1057	0.0501	0.0557
133	Sep-10	0.1059	0.0501	0.0558
134	Oct-10	0.1044	0.0510	0.0534
135	Nov-10	0.1051	0.0536	0.0514
136	Dec-10	0.1053	0.0557	0.0497
137	Jan-11	0.1044	0.0557	0.0487
138	Feb-11	0.1041	0.0568	0.0473
139	Mar-11	0.1044	0.0556	0.0488
140	Apr-11	0.1020	0.0555	0.0465
141	May-11	0.0994	0.0532	0.0462
142	Jun-11	0.1043	0.0526	0.0517
143	Jul-11	0.1019	0.0527	0.0492
144	Aug-11	0.1050	0.0469	0.0581
145	Sep-11	0.1016	0.0448	0.0568
146	Oct-11	0.1032	0.0452	0.0580
147	Nov-11	0.1014	0.0425	0.0589

Line	Date	DCF	Bond Yield	Risk Premium
148	Dec-11	0.1024	0.0435	0.0589
149	Jan-12	0.1016	0.0434	0.0582
150	Feb-12	0.0974	0.0436	0.0538
151	Mar-12	0.0971	0.0448	0.0523
152	Apr-12	0.0994	0.0440	0.0554
153	May-12	0.0981	0.0420	0.0561
154	Jun-12	0.0962	0.0408	0.0554
155	Jul-12	0.0963	0.0393	0.0570
156	Aug-12	0.0972	0.0400	0.0572
157	Sep-12	0.0968	0.0402	0.0566
158	Oct-12	0.0978	0.0391	0.0587
159	Nov-12	0.0935	0.0384	0.0551
160	Dec-12	0.0962	0.0400	0.0562
161	Jan-13	0.0968	0.0415	0.0553
162	Feb-13	0.0956	0.0418	0.0538

Notes: Utility bond yield information from *Mergent Bond Record* (formerly Moody's). See Appendix 4 for a description of my ex ante risk premium approach. DCF results are calculated using a quarterly DCF model as follows:

d_0 = Latest quarterly dividend per Value Line, Thomson Reuters
P_0 = Average of the monthly high and low stock prices for each month per Thomson Reuters
FC = Flotation cost allowance (5%) as a percentage of stock price
g = I/B/E/S forecast of future earnings growth for each month.
k = Cost of equity using the quarterly version of the DCF model.

$$k = \left[\frac{d_0 (1+g)^{\frac{1}{4}}}{P_0 (1 - FC)} + (1+g)^{\frac{1}{4}} \right]^4 - 1$$

EXHIBIT JVW-1 SCHEDULE 3
COMPARATIVE RETURNS ON S&P 500 STOCK INDEX
AND MOODY'S A-RATED UTILITY BONDS 1937 – 2013

Line	Year	S&P 500 Stock Price	Stock Dividend Yield	Stock Return	A-rated Bond Price	Bond Return	Risk Premium
1	2013	1,481.11	0.0220		$97.45		
2	2012	1,300.58	0.0214	16.02%	$94.36	7.52%	8.50%
3	2011	1,282.62	0.0185	3.25%	$77.36	27.14%	-23.89%
4	2010	1,123.58	0.0203	16.18%	$75.02	8.44%	7.74%
5	2009	865.58	0.0310	32.91%	$68.43	15.48%	17.43%
6	2008	1,378.76	0.0206	-35.16%	$72.25	0.24%	-35.40%
7	2007	1,424.16	0.0181	-1.38%	$72.91	4.59%	-5.97%
8	2006	1,278.72	0.0183	13.20%	$75.25	2.20%	11.01%
9	2005	1,181.41	0.0177	10.01%	$74.91	5.80%	4.21%
10	2004	1,132.52	0.0162	5.94%	$70.87	11.34%	-5.40%
11	2003	895.84	0.0180	28.22%	$62.26	20.27%	7.95%
12	2002	1,140.21	0.0138	-20.05%	$57.44	15.35%	-35.40%
13	2001	1,335.63	0.0116	-13.47%	$56.40	8.93%	-22.40%
14	2000	1,425.59	0.0118	-5.13%	$52.60	14.82%	-19.95%
15	1999	1,248.77	0.0130	15.46%	$63.03	-10.20%	25.66%
16	1998	963.35	0.0162	31.25%	$62.43	7.38%	23.87%
17	1997	766.22	0.0195	27.68%	$56.62	17.32%	10.36%
18	1996	614.42	0.0231	27.02%	$60.91	-0.48%	27.49%
19	1995	465.25	0.0287	34.93%	$50.22	29.26%	5.68%
20	1994	472.99	0.0269	1.05%	$60.01	-9.65%	10.71%
21	1993	435.23	0.0288	11.56%	$53.13	20.48%	-8.93%
22	1992	416.08	0.0290	7.50%	$49.56	15.27%	-7.77%
23	1991	325.49	0.0382	31.65%	$44.84	19.44%	12.21%
24	1990	339.97	0.0341	-0.85%	$45.60	7.11%	-7.96%
25	1989	285.41	0.0364	22.76%	$43.06	15.18%	7.58%
26	1988	250.48	0.0366	17.61%	$40.10	17.36%	0.25%
27	1987	264.51	0.0317	-2.13%	$48.92	-9.84%	7.71%
28	1986	208.19	0.0390	30.95%	$39.98	32.36%	-1.41%
29	1985	171.61	0.0451	25.83%	$32.57	35.05%	-9.22%
30	1984	166.39	0.0427	7.41%	$31.49	16.12%	-8.72%
31	1983	144.27	0.0479	20.12%	$29.41	20.65%	-0.53%
32	1982	117.28	0.0595	28.96%	$24.48	36.48%	-7.51%
33	1981	132.97	0.0480	-7.00%	$29.37	-3.01%	-3.99%
34	1980	110.87	0.0541	25.34%	$34.69	-3.81%	29.16%
35	1979	99.71	0.0533	16.52%	$43.91	-11.89%	28.41%
36	1978	90.25	0.0532	15.80%	$49.09	-2.40%	18.20%
37	1977	103.80	0.0399	-9.06%	$50.95	4.20%	-13.27%
38	1976	96.86	0.0380	10.96%	$43.91	25.13%	-14.17%

Line	Year	S&P 500 Stock Price	Stock Dividend Yield	Stock Return	A-rated Bond Price	Bond Return	Risk Premium
39	1975	72.56	0.0507	38.56%	$41.76	14.75%	23.81%
40	1974	96.11	0.0364	-20.86%	$52.54	-12.91%	-7.96%
41	1973	118.40	0.0269	-16.14%	$58.51	-3.37%	-12.77%
42	1972	103.30	0.0296	17.58%	$56.47	10.69%	6.89%
43	1971	93.49	0.0332	13.81%	$53.93	12.13%	1.69%
44	1970	90.31	0.0356	7.08%	$50.46	14.81%	-7.73%
45	1969	102.00	0.0306	-8.40%	$62.43	-12.76%	4.36%
46	1968	95.04	0.0313	10.45%	$66.97	-0.81%	11.26%
47	1967	84.45	0.0351	16.05%	$78.69	-9.81%	25.86%
48	1966	93.32	0.0302	-6.48%	$86.57	-4.48%	-2.00%
49	1965	86.12	0.0299	11.35%	$91.40	-0.91%	12.26%
50	1964	76.45	0.0305	15.70%	$92.01	3.68%	12.02%
51	1963	65.06	0.0331	20.82%	$93.56	2.61%	18.20%
52	1962	69.07	0.0297	-2.84%	$89.60	8.89%	-11.73%
53	1961	59.72	0.0328	18.94%	$89.74	4.29%	14.64%
54	1960	58.03	0.0327	6.18%	$84.36	11.13%	-4.95%
55	1959	55.62	0.0324	7.57%	$91.55	-3.49%	11.06%
56	1958	41.12	0.0448	39.74%	$101.22	-5.60%	45.35%
57	1957	45.43	0.0431	-5.18%	$100.70	4.49%	-9.67%
58	1956	44.15	0.0424	7.14%	$113.00	-7.35%	14.49%
59	1955	35.60	0.0438	28.40%	$116.77	0.20%	28.20%
60	1954	25.46	0.0569	45.52%	$112.79	7.07%	38.45%
61	1953	26.18	0.0545	2.70%	$114.24	2.24%	0.46%
62	1952	24.19	0.0582	14.05%	$113.41	4.26%	9.79%
63	1951	21.21	0.0634	20.39%	$123.44	-4.89%	25.28%
64	1950	16.88	0.0665	32.30%	$125.08	1.89%	30.41%
65	1949	15.36	0.0620	16.10%	$119.82	7.72%	8.37%
66	1948	14.83	0.0571	9.28%	$118.50	4.49%	4.79%
67	1947	15.21	0.0449	1.99%	$126.02	-2.79%	4.79%
68	1946	18.02	0.0356	-12.03%	$126.74	2.59%	-14.63%
69	1945	13.49	0.0460	38.18%	$119.82	9.11%	29.07%
70	1944	11.85	0.0495	18.79%	$119.82	3.34%	15.45%
71	1943	10.09	0.0554	22.98%	$118.50	4.49%	18.49%
72	1942	8.93	0.0788	20.87%	$117.63	4.14%	16.73%
73	1941	10.55	0.0638	-8.98%	$116.34	4.55%	-13.52%
74	1940	12.30	0.0458	-9.65%	$112.39	7.08%	-16.73%
75	1939	12.50	0.0349	1.89%	$105.75	10.05%	-8.16%
76	1938	11.31	0.0784	18.36%	$99.83	9.94%	8.42%
77	1937	17.59	0.0434	-31.36%	$103.18	0.63%	-31.99%
78	Average			11.1%		6.7%	4.4%

Note: See Appendix 5 for an explanation of how stock and bond returns are derived and the source of the data presented.

EXHIBIT JVW-1 SCHEDULE 4
COMPARATIVE RETURNS ON S&P UTILITY STOCK INDEX
AND MOODY'S A-RATED UTILITY BONDS 1937 – 2013

Line	Year	S&P Utility Stock Price	Stock Dividend Yield	Stock Return	A-rated Bond Price	Bond Return	Risk Premium
1	2013				$97.45		
2	2012			2.09%	$94.36	7.52%	-5.43%
3	2011			19.99%	$77.36	27.14%	-7.15%
4	2010			7.04%	$75.02	8.44%	-1.40%
5	2009			10.71%	$68.43	15.48%	-4.77%
6	2008			-25.90%	$72.25	0.24%	-26.14%
7	2007			16.56%	$72.91	4.59%	11.96%
8	2006			20.76%	$75.25	2.20%	18.56%
9	2005			16.05%	$74.91	5.80%	10.25%
10	2004			22.84%	$70.87	11.34%	11.50%
11	2003			23.48%	$62.26	20.27%	3.21%
12	2002			-14.73%	$57.44	15.35%	-30.08%
13	2001	307.70	0.0287	-17.90%	$56.40	8.93%	-26.83%
14	2000	239.17	0.0413	32.78%	$52.60	14.82%	17.96%
15	1999	253.52	0.0394	-1.72%	$63.03	-10.20%	8.48%
16	1998	228.61	0.0457	15.47%	$62.43	7.38%	8.09%
17	1997	201.14	0.0492	18.58%	$56.62	17.32%	1.26%
18	1996	202.57	0.0454	3.83%	$60.91	-0.48%	4.31%
19	1995	153.87	0.0584	37.49%	$50.22	29.26%	8.23%
20	1994	168.70	0.0496	-3.83%	$60.01	-9.65%	5.82%
21	1993	159.79	0.0537	10.95%	$53.13	20.48%	-9.54%
22	1992	149.70	0.0572	12.46%	$49.56	15.27%	-2.81%
23	1991	138.38	0.0607	14.25%	$44.84	19.44%	-5.19%
24	1990	146.04	0.0558	0.33%	$45.60	7.11%	-6.78%
25	1989	114.37	0.0699	34.68%	$43.06	15.18%	19.51%
26	1988	106.13	0.0704	14.80%	$40.10	17.36%	-2.55%
27	1987	120.09	0.0588	-5.74%	$48.92	-9.84%	4.10%
28	1986	92.06	0.0742	37.87%	$39.98	32.36%	5.51%
29	1985	75.83	0.0860	30.00%	$32.57	35.05%	-5.04%
30	1984	68.50	0.0925	19.95%	$31.49	16.12%	3.83%
31	1983	61.89	0.0948	20.16%	$29.41	20.65%	-0.49%
32	1982	51.81	0.1074	30.20%	$24.48	36.48%	-6.28%
33	1981	52.01	0.0978	9.40%	$29.37	-3.01%	12.41%
34	1980	50.26	0.0953	13.01%	$34.69	-3.81%	16.83%
35	1979	50.33	0.0893	8.79%	$43.91	-11.89%	20.68%
36	1978	52.40	0.0791	3.96%	$49.09	-2.40%	6.36%
37	1977	54.01	0.0714	4.16%	$50.95	4.20%	-0.04%

Florida Public Service Commission
Docket No. 130140-EI
GULF POWER COMPANY
Witness: James H. Vander Weide, Ph.D.
Exhibit No. _____ (JVW-1)
Schedule 4
Page 2 of 3

Line	Year	S&P Utility Stock Price	Stock Dividend Yield	Stock Return	A-rated Bond Price	Bond Return	Risk Premium
38	1976	46.99	0.0776	22.70%	$43.91	25.13%	-2.43%
39	1975	38.19	0.0920	32.24%	$41.76	14.75%	17.49%
40	1974	48.60	0.0713	-14.29%	$52.54	-12.91%	-1.38%
41	1973	60.01	0.0556	-13.45%	$58.51	-3.37%	-10.08%
42	1972	60.19	0.0542	5.12%	$56.47	10.69%	-5.57%
43	1971	63.43	0.0504	-0.07%	$53.93	12.13%	-12.19%
44	1970	55.72	0.0561	19.45%	$50.46	14.81%	4.64%
45	1969	68.65	0.0445	-14.38%	$62.43	-12.76%	-1.62%
46	1968	68.02	0.0435	5.28%	$66.97	-0.81%	6.08%
47	1967	70.63	0.0392	0.22%	$78.69	-9.81%	10.03%
48	1966	74.50	0.0347	-1.72%	$86.57	-4.48%	2.76%
49	1965	75.87	0.0315	1.34%	$91.40	-0.91%	2.25%
50	1964	67.26	0.0331	16.11%	$92.01	3.68%	12.43%
51	1963	63.35	0.0330	9.47%	$93.56	2.61%	6.86%
52	1962	62.69	0.0320	4.25%	$89.60	8.89%	-4.64%
53	1961	52.73	0.0358	22.47%	$89.74	4.29%	18.18%
54	1960	44.50	0.0403	22.52%	$84.36	11.13%	11.39%
55	1959	43.96	0.0377	5.00%	$91.55	-3.49%	8.49%
56	1958	33.30	0.0487	36.88%	$101.22	-5.60%	42.48%
57	1957	32.32	0.0487	7.90%	$100.70	4.49%	3.41%
58	1956	31.55	0.0472	7.16%	$113.00	-7.35%	14.51%
59	1955	29.89	0.0461	10.16%	$116.77	0.20%	9.97%
60	1954	25.51	0.0520	22.37%	$112.79	7.07%	15.30%
61	1953	24.41	0.0511	9.62%	$114.24	2.24%	7.38%
62	1952	22.22	0.0550	15.36%	$113.41	4.26%	11.10%
63	1951	20.01	0.0606	17.10%	$123.44	-4.89%	21.99%
64	1950	20.20	0.0554	4.60%	$125.08	1.89%	2.71%
65	1949	16.54	0.0570	27.83%	$119.82	7.72%	20.10%
66	1948	16.53	0.0535	5.41%	$118.50	4.49%	0.92%
67	1947	19.21	0.0354	-10.41%	$126.02	-2.79%	-7.62%
68	1946	21.34	0.0298	-7.00%	$126.74	2.59%	-9.59%
69	1945	13.91	0.0448	57.89%	$119.82	9.11%	48.79%
70	1944	12.10	0.0569	20.65%	$119.82	3.34%	17.31%
71	1943	9.22	0.0621	37.45%	$118.50	4.49%	32.96%
72	1942	8.54	0.0940	17.36%	$117.63	4.14%	13.22%
73	1941	13.25	0.0717	-28.38%	$116.34	4.55%	-32.92%
74	1940	16.97	0.0540	-16.52%	$112.39	7.08%	-23.60%
75	1939	16.05	0.0553	11.26%	$105.75	10.05%	1.21%
76	1938	14.30	0.0730	19.54%	$99.83	9.94%	9.59%
77	1937	24.34	0.0432	-36.93%	$103.18	0.63%	-37.55%
78	Average			10.5%		6.7%	3.7%

Note: See Appendix 5 for an explanation of how stock and bond returns are derived and the source of the data presented. Standard & Poor's discontinued its S&P Utilities Index in December 2001 and replaced its utilities stock index with separate indices for electric and natural gas utilities. In this study, the stock returns beginning in 2002 are based on the total returns for the EEI Index of U.S. shareholder-owned electric utilities, as reported by EEI on its website.
http://www.eei.org/whatwedo/DataAnalysis/IndusFinanAnalysis/Pages/QtrlyFinancialUpdates.aspx

EXHIBIT JVW-1 SCHEDULE 5
USING THE ARITHMETIC MEAN TO ESTIMATE
THE COST OF EQUITY CAPITAL

Consider an investment that in a given year generates a return of 30 percent with probability equal to .5 and a return of -10 percent with a probability equal to .5. For each one dollar invested, the possible outcomes of this investment at the end of year one are:

Ending Wealth	Probability
$1.30	0.50
$0.90	0.50

At the end of year two, the possible outcomes are:

Ending Wealth			Probability	Value x Probability
(1.30) (1.30)	=	$1.69	0.25	0.4225
(1.30) (.9)	=	$1.17	0.50	0.5850
(.9) (.9)	=	$0.81	0.25	0.2025
Expected Wealth	=			$1.21

The expected value of this investment at the end of year two is $1.21. In a competitive capital market, the cost of equity is equal to the expected rate of return on an investment. In the above example, the cost of equity is that rate of return which will make the initial investment of one dollar grow to the expected value of $1.21 at the end of two years. Thus, the cost of equity is the solution to the equation:

$$1(1+k)^2 = 1.21 \text{ or}$$

$$k = (1.21/1)^{.5} - 1 = 10\%.$$

The arithmetic mean of this investment is:

$$(30\%)\ (.5) + (-10\%)\ (.5) = 10\%.$$

Thus, the arithmetic mean is equal to the cost of equity capital.

The geometric mean of this investment is:

$$[(1.3)\ (.9)]^{.5} - 1 = .082 = 8.2\%.$$

Thus, the geometric mean is not equal to the cost of equity capital.

The lesson is obvious: for an investment with an uncertain outcome, the arithmetic mean is the best measure of the cost of equity capital.

EXHIBIT JVW-1 SCHEDULE-6
CALCULATION OF CAPITAL ASSET PRICING MODEL COST OF EQUITY
USING THE IBBOTTSON SBBI 6.7 PERCENT RISK PREMIUM
ELECTRIC UTILITIES AND VALUE LINE PIPELINE COMPANIES

Line		Value	Description
1	Risk-free Rate	5.25%	Long-term Treasury bond yield forecast
2	Beta	0.73	Average Beta Electric Utilities
3	Risk Premium	6.7%	Long-horizon SBBI risk premium
4	Beta x Risk Premium	4.9%	
5	Flotation	0.24%	
6	Model Result	10.4%	

Risk premium from 2013 Ibbotson® SBBI®. Value Line beta for comparable companies from Value Line Investment Analyzer. Treasury bond yield forecast from data in Value Line Selection & Opinion, Feb. 22, 2013, and Energy Information Administration, January 2013, determined as follows. Value Line forecasts a yield on 10-year Treasury notes equal to 4.2 percent. The current spread between the average February 2013 yield on 10-year Treasury notes (1.98 percent) and 20-year Treasury bonds (2.78 percent) is eighty basis points. Adding eighty basis points to Value Line's 4.2 percent forecasted yield on 10-year Treasury notes produces a forecasted yield of 5.0 percent for 20-year Treasury bonds (see Value Line Investment Survey, Selection & Opinion, Feb. 22, 2013). EIA forecasts a yield of 4.7 percent on 10-year Treasury notes. Adding the eighty basis point spread between 10-year Treasury notes and 20-year Treasury bonds to the EIA forecast of 4.7 percent for 10-year Treasury notes produces an EIA forecast for 20-year Treasury bonds equal to 5.5 percent. The average of the forecasts is 5.25 percent (5.0 percent using Value Line data and 5.5 percent using EIA data).

PROXY COMPANY BETAS

Line	Company	Value Line Beta
1	ALLETE	0.70
2	Alliant Energy	0.70
3	Amer. Elec. Power	0.65
4	Black Hills	0.80
5	CenterPoint Energy	0.80
6	CMS Energy Corp.	0.75
7	Dominion Resources	0.65
8	DTE Energy	0.75
9	Duke Energy	0.60
10	Entergy Corp.	0.70
11	G't Plains Energy	0.75
12	Hawaiian Elec.	0.70
13	Integrys Energy	0.90
14	NextEra Energy	0.70
15	Northeast Utilities	0.70
16	NorthWestern Corp.	0.70
17	OGE Energy	0.75
18	Otter Tail Corp.	0.90
19	Pepco Holdings	0.75
20	Pinnacle West Capital	0.70
21	PNM Resources	0.95
22	Portland General	0.75
23	SCANA Corp.	0.65
24	Sempra Energy	0.80
25	Southern Co.	0.55
26	TECO Energy	0.85
27	Vectren Corp.	0.70
28	Westar Energy	0.70
29	Wisconsin Energy	0.60
30	Xcel Energy Inc.	0.60
31	Average	0.73

Data from Value Line Investment Analyzer.

EXHIBIT JVW-1 SCHEDULE-7
COMPARISON OF RISK PREMIUMS ON
S&P500 AND S&P UTILITIES 1937 – 2013

Year	S&P Utilities Stock Return	Sp500 Stock Return	10-Yr. Treasury Bond Yield	Utilities Risk Premium	Market Risk Premium
2012	0.0209	0.1602	0.0180	0.1721	0.1422
2011	0.1999	0.0325	0.0278	0.1721	0.0047
2010	0.0704	0.1618	0.0322	0.0382	0.1296
2009	0.1071	0.3291	0.0326	0.0745	0.2965
2008	-0.2590	-0.3519	0.0367	-0.2957	-0.3886
2007	0.1656	-0.0127	0.0463	0.1193	-0.0590
2006	0.2076	0.1320	0.0479	0.1597	0.0841
2005	0.1605	0.1001	0.0429	0.1176	0.0572
2004	0.2284	0.0594	0.0427	0.1857	0.0167
2003	0.2348	0.2822	0.0401	0.1947	0.2421
2002	-0.1473	-0.2005	0.0461	-0.1934	-0.2466
2001	-0.1790	-0.1347	0.0502	-0.2292	-0.1849
2000	0.3278	-0.0513	0.0603	0.2675	-0.1116
1999	-0.0172	0.1546	0.0564	-0.0736	0.0982
1998	0.1547	0.3125	0.0526	0.1021	0.2599
1997	0.1858	0.2768	0.0635	0.1223	0.2133
1996	0.0383	0.2702	0.0644	-0.0261	0.2058
1995	0.3749	0.3493	0.0658	0.3091	0.2835
1994	-0.0383	0.0105	0.0708	-0.1091	-0.0603
1993	0.1095	0.1156	0.0587	0.0508	0.0569
1992	0.1246	0.0750	0.0701	0.0545	0.0049
1991	0.1425	0.3165	0.0786	0.0639	0.2379
1990	0.0033	-0.0085	0.0855	-0.0822	-0.0940
1989	0.3468	0.2276	0.0850	0.2618	0.1426
1988	0.1480	0.1761	0.0884	0.0596	0.0877
1987	-0.0574	-0.0213	0.0838	-0.1412	-0.1051
1986	0.3787	0.3095	0.0768	0.3019	0.2327
1985	0.3000	0.2583	0.1062	0.1938	0.1521
1984	0.1995	0.0741	0.1244	0.0751	-0.0503
1983	0.2016	0.2012	0.1110	0.0906	0.0902
1982	0.3020	0.2896	0.1300	0.1720	0.1596
1981	0.0940	-0.0700	0.1391	-0.0451	-0.2091
1980	0.1301	0.2534	0.1146	0.0155	0.1388
1979	0.0879	0.1652	0.0944	-0.0065	0.0708
1978	0.0396	0.1580	0.0841	-0.0445	0.0739

Year	S&P Utilities Stock Return	Sp500 Stock Return	10-Yr. Treasury Bond Yield	Utilities Risk Premium	Market Risk Premium
1977	0.0416	-0.0906	0.0742	-0.0326	-0.1648
1976	0.2270	0.1096	0.0761	0.1509	0.0335
1975	0.3224	0.3856	0.0799	0.2425	0.3057
1974	-0.1429	-0.2086	0.0756	-0.2185	-0.2842
1973	-0.1345	-0.1614	0.0684	-0.2029	-0.2298
1972	0.0512	0.1758	0.0621	-0.0109	0.1137
1971	-0.0007	0.1381	0.0616	-0.0623	0.0765
1970	0.1945	0.0708	0.0735	0.1210	-0.0027
1969	-0.1438	-0.0840	0.0667	-0.2105	-0.1507
1968	0.0528	0.1045	0.0565	-0.0037	0.0480
1967	0.0022	0.1605	0.0507	-0.0485	0.1098
1966	-0.0172	-0.0648	0.0492	-0.0664	-0.1140
1965	0.0134	0.1135	0.0428	-0.0294	0.0707
1964	0.1611	0.1570	0.0419	0.1192	0.1151
1963	0.0947	0.2082	0.0400	0.0547	0.1682
1962	0.0425	-0.0284	0.0395	0.0030	-0.0679
1961	0.2247	0.1894	0.0388	0.1859	0.1506
1960	0.2252	0.0618	0.0412	0.1840	0.0206
1959	0.0500	0.0757	0.0433	0.0067	0.0324
1958	0.3688	0.3974	0.0332	0.3356	0.3642
1957	0.0790	-0.0518	0.0365	0.0425	-0.0883
1956	0.0716	0.0714	0.0318	0.0398	0.0396
1955	0.1016	0.2840	0.0282	0.0734	0.2558
1954	0.2237	0.4552	0.0240	0.1997	0.4312
1953	0.0962	0.0270	0.0281	0.0681	-0.0011
1952	0.1536	0.1405	0.0248	0.1288	0.1157
1951	0.1710	0.2039	0.0241	0.1469	0.1798
1950	0.0460	0.3230	0.0205	0.0255	0.3025
1949	0.2783	0.1610	0.0193	0.2590	0.1417
1948	0.0541	0.0928	0.0215	0.0326	0.0713
1947	-0.1041	0.0199	0.0185	-0.1226	0.0014
1946	-0.0700	-0.1203	0.0174	-0.0874	-0.1377
1945	0.5789	0.3818	0.0173	0.5616	0.3645
1944	0.2065	0.1879	0.0209	0.1856	0.1670
1943	0.3745	0.2298	0.0207	0.3538	0.2091
1942	0.1736	0.2087	0.0211	0.1525	0.1876
1941	-0.2838	-0.0898	0.0199	-0.3037	-0.1097
1940	-0.1652	-0.0965	0.0220	-0.1872	-0.1185

Year	S&P Utilities Stock Return	Sp500 Stock Return	10-Yr. Treasury Bond Yield	Utilities Risk Premium	Market Risk Premium
1939	0.1126	0.0189	0.0235	0.0891	-0.0046
1938	0.1954	0.1836	0.0255	0.1699	0.1581
1937	-0.3693	-0.3136	0.0269	-0.3962	-0.3405
Risk Premium 1937—2013				0.0514	0.0578
RP Utilities/RP SP500				0.89	

EXHIBIT JVW-1 SCHEDULE 8
CALCULATION OF CAPITAL ASSET PRICING MODEL COST OF EQUITY
USING DCF ESTIMATE OF THE EXPECTED RATE OF RETURN
ON THE MARKET PORTFOLIO

Line			
1	Risk-free Rate	5.25%	Forecast 20-year Treasury Bond Yield
2	Beta	0.73	Average Beta Electric Utilities
3	DCF S&P 500	12.4%	DCF Cost of Equity S&P 500 (see following)
4	Risk Premium	7.4%	
5	Beta x Risk Premium	5.25%	
6	Flotation cost	0.24%	
7	Model Result	10.7%	

Value Line beta for comparable companies from Value Line Investment Analyzer. Treasury bond yield forecast from data in Value Line Selection & Opinion, Feb. 22, 2013, and Energy Information Administration, January 2013, determined as follows. Value Line forecasts a yield on 10-year Treasury notes equal to 4.2 percent. The current spread between the average February 2013 yield on 10-year Treasury notes (1.98 percent) and 20-year Treasury bonds (2.78 percent) is eighty basis points. Adding eighty basis points to Value Line's 4.2 percent forecasted yield on 10-year Treasury notes produces a forecasted yield of 5.0 percent for 20-year Treasury bonds (see Value Line Investment Survey, Selection & Opinion, Feb. 22, 2013). EIA forecasts a yield of 4.7 percent on 10-year Treasury notes. Adding the eighty basis point spread between 10-year Treasury notes and 20-year Treasury bonds to the EIA forecast of 4.7 percent for 10-year Treasury notes produces an EIA forecast for 20-year Treasury bonds equal to 5.5 percent. The average of the forecasts is 5.25 percent (5.0 percent using Value Line data and 5.5 percent using EIA data).

EXHIBIT JVW-1 SCHEDULE 8 (CONTINUED)
SUMMARY OF DISCOUNTED CASH FLOW ANALYSIS
FOR S&P 500 COMPANIES

Line	COMPANY	P_0	D_0	Growth	Model Result
1	3M	97.46	2.54	9.83%	12.7%
2	ABBOTT LABORATORIES	32.81	0.56	11.73%	13.6%
3	ACCENTURE CLASS A	70.78	1.62	11.22%	13.8%
4	ADT	46.55	0.50	11.10%	12.3%
5	AIR PRDS.& CHEMS.	85.96	2.56	8.94%	12.2%
6	AIRGAS	93.40	1.60	12.48%	14.4%
7	ALLERGAN	99.76	0.20	12.89%	13.1%
8	ALLSTATE	42.92	1.00	8.25%	10.8%
9	ALTERA	33.96	0.40	12.00%	13.3%
10	AMERICAN EXPRESS	59.39	0.80	10.94%	12.4%
11	AMERISOURCEBERGEN	44.76	0.84	12.00%	14.1%
12	AMGEN	87.14	1.88	9.93%	12.3%
13	ASSURANT	37.27	0.84	9.67%	12.2%
14	AT&T	34.55	1.80	5.50%	11.1%
15	AUTOMATIC DATA PROC.	58.99	1.74	9.20%	12.5%
16	AVERY DENNISON	37.08	1.08	10.13%	13.4%
17	BAKER HUGHES	43.76	0.60	9.64%	11.2%
18	BALL	44.89	0.52	10.30%	11.6%
19	BAXTER INTL.	67.05	1.80	8.78%	11.7%
20	BEAM	60.50	0.90	11.73%	13.4%
21	BOEING	75.39	1.94	10.67%	13.5%
22	BOSTON PROPERTIES	105.74	2.60	9.47%	12.2%
23	CARDINAL HEALTH	43.27	1.10	10.50%	13.3%
24	CBS 'B'	40.10	0.48	12.02%	13.4%
25	CH ROBINSON WWD.	62.84	1.40	12.19%	14.7%
26	CINTAS	42.41	0.64	10.30%	12.0%
27	CISCO SYSTEMS	20.48	0.56	8.40%	11.4%
28	CITIGROUP	40.55	0.04	12.44%	12.6%
29	CLOROX	77.54	2.56	8.00%	11.6%
30	COCA COLA	37.26	1.12	8.95%	12.3%
31	COCA COLA ENTS.	33.54	0.80	10.27%	12.9%
32	COLGATE-PALM.	108.58	2.48	9.70%	12.2%
33	CONAGRA FOODS	31.64	1.00	8.80%	12.3%
34	COSTCO WHOLESALE	101.50	1.10	13.04%	14.3%
35	CUMMINS	111.18	2.00	9.67%	11.7%
36	DANAHER	58.18	0.10	12.87%	13.1%
37	DARDEN RESTAURANTS	46.78	2.00	6.60%	11.2%
38	DEERE	88.92	2.04	10.00%	12.5%
39	DELL	11.98	0.32	8.43%	11.4%
40	DENTSPLY INTL.	40.97	0.25	10.83%	11.5%
41	DISCOVER FINANCIAL SVS.	39.19	0.56	10.67%	12.3%
42	DOW CHEMICAL	32.10	1.28	6.62%	10.9%
43	EMERSON ELECTRIC	54.83	1.64	9.13%	12.4%
44	EQUIFAX	55.70	0.88	12.89%	14.7%

Line	COMPANY	P_0	D_0	Growth	Model Result
45	EXPEDIA	62.83	0.52	13.46%	14.4%
46	FAMILY DOLLAR STORES	61.00	0.84	12.86%	14.4%
47	FEDEX	98.15	0.56	12.76%	13.4%
48	FIDELITY NAT.INFO.SVS.	36.21	0.88	11.86%	14.6%
49	FLUOR	60.77	0.64	10.80%	12.0%
50	FMC	58.78	0.54	11.12%	12.1%
51	FORD MOTOR	12.75	0.40	10.53%	14.0%
52	GAP	32.31	0.60	9.37%	11.4%
53	GARMIN	39.30	1.80	6.62%	11.6%
54	GENERAL MILLS	42.08	1.32	7.93%	11.4%
55	HASBRO	37.79	1.60	6.88%	11.5%
56	HONEYWELL INTL.	66.33	1.64	10.42%	13.2%
57	HUMANA	70.69	1.04	10.50%	12.1%
58	ILLINOIS TOOL WORKS	62.16	1.52	8.43%	11.1%
59	INGERSOLL-RAND	50.19	0.84	10.93%	12.8%
60	INTERNATIONAL BUS.MCHS.	197.54	3.40	9.86%	11.8%
61	INTERPUBLIC GP.	11.72	0.30	8.44%	11.2%
62	INTUIT	61.83	0.68	13.43%	14.7%
63	J M SMUCKER	89.16	2.08	8.43%	11.0%
64	JOHNSON CONTROLS	30.53	0.76	11.57%	14.4%
65	JOY GLOBAL	62.94	0.70	12.67%	13.9%
66	KROGER	27.16	0.60	9.80%	12.2%
67	LIMITED BRANDS	46.84	1.20	11.17%	14.0%
68	LINEAR TECH.	35.81	1.04	9.48%	12.7%
69	LOCKHEED MARTIN	90.11	4.60	7.90%	13.5%
70	LYONDELLBASELL INDS.CL.A	57.74	1.60	9.54%	12.6%
71	M&T BANK	101.43	2.80	8.10%	11.1%
72	MARATHON PETROLEUM	69.20	1.40	8.90%	11.1%
73	MARSH & MCLENNAN	35.22	0.92	11.68%	14.6%
74	MATTEL	37.58	1.44	10.03%	14.3%
75	MCDONALDS	91.94	3.08	8.89%	12.6%
76	MEAD JOHNSON NUTRITION	71.82	1.36	10.80%	12.9%
77	MICROSOFT	27.30	0.92	8.38%	12.1%
78	MONSANTO	97.32	1.50	11.08%	12.8%
79	MURPHY OIL	60.39	1.25	12.30%	14.6%
80	NABORS INDS.	15.58	0.16	10.93%	12.1%
81	NASDAQ OMX GROUP	27.37	0.52	10.25%	12.4%
82	NIKE 'B'	52.97	0.84	10.37%	12.1%
83	NOBLE ENERGY	105.56	1.00	12.23%	13.3%
84	NORDSTROM	53.90	1.20	11.39%	13.9%
85	NORFOLK SOUTHERN	66.35	2.00	10.45%	13.8%
86	NUCOR	44.78	1.47	7.88%	11.5%
87	NVIDIA	12.42	0.30	10.60%	13.3%
88	OMNICOM GP.	52.77	1.60	9.03%	12.4%
89	ORACLE	34.31	0.24	11.97%	12.8%
90	PATTERSON COMPANIES	35.24	0.56	12.00%	13.8%
91	PERKINELMER	33.08	0.28	11.95%	12.9%
92	PERRIGO	106.81	0.36	11.72%	12.1%
93	PRAXAIR	110.38	2.40	12.07%	14.5%

Line	COMPANY	P_0	D_0	Growth	Model Result
94	PREC.CASTPARTS	186.40	0.12	14.40%	14.5%
95	PRINCIPAL FINL.GP.	29.69	0.92	11.07%	14.6%
96	PROCTER & GAMBLE	72.39	2.25	7.93%	11.3%
97	QUEST DIAGNOSTICS	58.51	1.20	10.82%	13.1%
98	RALPH LAUREN CL.A	160.63	1.60	13.13%	14.3%
99	REYNOLDS AMERICAN	43.28	2.36	7.30%	13.3%
100	ROCKWELL AUTOMATION	86.10	1.88	10.62%	13.1%
101	ROCKWELL COLLINS	58.89	1.20	9.65%	11.9%
102	ROSS STORES	57.05	0.68	12.80%	14.2%
103	SEALED AIR	18.80	0.52	9.77%	12.8%
104	ST.JUDE MEDICAL	38.58	1.00	9.41%	12.3%
105	STRYKER	59.32	1.06	8.85%	10.8%
106	TARGET	61.05	1.44	11.53%	14.2%
107	TE CONNECTIVITY	38.30	0.84	10.14%	12.6%
108	TESORO	46.43	0.80	12.79%	14.7%
109	THE HERSHEY COMPANY	76.71	1.68	9.40%	11.8%
110	THERMO FISHER SCIENTIFIC	68.71	0.60	11.42%	12.4%
111	TIFFANY & CO	61.37	1.28	10.15%	12.5%
112	TJX COS.	43.80	0.46	12.03%	13.2%
113	TOTAL SYSTEM SERVICES	22.43	0.40	10.32%	12.3%
114	TRAVELERS COS.	76.09	1.84	10.05%	12.7%
115	UNITED PARCEL SER.'B'	78.30	2.48	9.90%	13.4%
116	UNITEDHEALTH GP.	54.65	0.85	10.94%	12.7%
117	US BANCORP	32.90	0.78	9.69%	12.3%
118	V F	152.90	3.48	11.67%	14.2%
119	VALERO ENERGY	39.21	0.80	10.16%	12.4%
120	VERIZON COMMUNICATIONS	44.12	2.06	6.33%	11.4%
121	WAL MART STORES	69.72	1.88	8.88%	11.8%
122	WALT DISNEY	52.34	0.75	11.24%	12.8%
123	WELLS FARGO & CO	34.66	1.00	9.33%	12.5%
124	WYNN RESORTS	117.73	4.00	10.90%	14.7%
125	XILINX	36.55	0.88	8.53%	11.2%
126	YUM! BRANDS	65.20	1.34	11.70%	14.0%
127	Market-weighted Average				12.4%

Notes: In applying the DCF model to the S&P 500, I included in the DCF analysis only those companies in the S&P 500 group which pay a dividend, have a positive growth rate, and have at least three analysts' long-term growth estimates. I also eliminated those 25% of companies with the highest and lowest DCF results, a decision which had no impact on my CAPM estimate of the cost of equity.

D_0 = Current dividend per Thomson Reuters.
P_0 = Average of the monthly high and low stock prices during the three months ending Febuary 2013 per Thomson Reuters.
g = I/B/E/S forecast of future earnings growth Febuary 2013.
k = Cost of equity using the quarterly version of the DCF model shown below:

$$k = \left[\frac{d_0(1+g)^{\frac{1}{4}}}{P_0} + (1+g)^{\frac{1}{4}} \right]^4 - 1$$

EXHIBIT JVW-1 SCHEDULE 9
ILLUSTRATION OF CALCULATION OF COST OF EQUITY
REQUIRED FOR THE COMPANY TO HAVE THE SAME WEIGHTED AVERAGE COST OF CAPITAL AS COMPARABLE ELECTRIC UTILITIES

WEIGHTED AVERAGE COST OF CAPITAL - VALUE LINE ELECTRIC UTILITIES			
Capital Source	Percent	After-tax Cost Rate	Weighted Cost
Short-term Debt	5.7%	0.50%	0.03%
Long-term Debt	38.6%	3.03%	1.17%
Preferred Stock	0.8%	6.00%	0.05%
Common Equity	54.9%	10.80%	5.93%
Total	100.0%		7.17%
Wtd. Cost of Debt and Preferred - Company			
Capital Source	Percent	After-tax Cost Rate	Weighted Cost
Short-term Debt	1.83%	0.50%	0.01%
Long-term Debt	45.46%	3.03%	1.38%
Preferred Stock	5.25%	6.00%	0.31%
Sum of Wtd. Cost of Debt and Preferred	52.54%		1.70%
Cost of Equity Required to Achieve Equivalent WACC			
(1) Ave. WACC Proxy Companies	7.17%		
(2) Wtd. Cost of Debt and Preferred	1.70%		
(1) Less (2)	5.47%		
Cost of Equity (5.47 ÷ 47.46 = 11.5)	11.5%		
Notes:			
	Before-tax Cost	After-tax Cost	Source
Tax rate	39%		
Short-term debt cost rate	0.82%	0.50%	Company
A-rated long-term debt	4.96%	3.03%	Company
A-rated preferred	6.00%		Company
Cost of equity	10.8%		Average cost of equity proxy group

EXHIBIT JVW-2 APPENDIX 1
QUALIFICATIONS OF JAMES H. VANDER WEIDE, PH.D.

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James H. Vander Weide is Research Professor of Finance and Economics at Duke University, the Fuqua School of Business. Dr. Vander Weide is also founder and President of Financial Strategy Associates, a consulting firm that provides strategic, financial, and economic consulting services to corporate clients, including cost of capital and valuation studies.

Educational Background and Prior Academic Experience

Dr. Vander Weide holds a Ph.D. in Finance from Northwestern University and a Bachelor of Arts in Economics from Cornell University. He joined the faculty at Duke University and was named Assistant Professor, Associate Professor, Professor, and then Research Professor of Finance and Economics.

Since joining the faculty at Duke, Dr. Vander Weide has taught courses in corporate finance, investment management, and management of financial institutions. He has also taught courses in statistics, economics, and operations research, and a Ph.D. seminar on the theory of public utility pricing. In addition, Dr. Vander Weide has been active in executive education at Duke and Duke Corporate Education, leading executive development seminars on topics including financial analysis, cost of capital, creating shareholder value, mergers and acquisitions, real options, capital budgeting, cash management, measuring corporate performance, valuation, short-run financial planning, depreciation policies, financial strategy, and competitive strategy. Dr. Vander Weide has designed and served as Program Director for several executive education programs, including the Advanced Management Program, Competitive Strategies in Telecommunications, and the Duke Program for Manager Development for managers from the former Soviet Union.

Publications

Dr. Vander Weide has written a book entitled *Managing Corporate Liquidity: An Introduction to Working Capital Management* published by John Wiley and Sons, Inc. He has also written a chapter titled, "Financial Management in the Short Run" for *The Handbook of Modern Finance;*" a chapter for *The Handbook of Portfolio Construction: Contemporary Applications of Markowitz Techniques,* "Principles for Lifetime Portfolio Selection: Lessons from Portfolio Theory," and written research papers on such topics as portfolio management, capital budgeting, investments, the effect of regulation on the performance of public utilities, and cash management.

His articles have been published in *American Economic Review, Financial Management, International Journal of Industrial Organization, Journal of Finance, Journal of Financial and Quantitative Analysis, Journal of Bank Research, Journal of Portfolio Management, Journal of Accounting Research, Journal of Cash Management, Management Science, Atlantic Economic Journal, Journal of Economics and Business,* and *Computers and Operations Research.*

Professional Consulting Experience

Dr. Vander Weide has provided financial and economic consulting services to firms in the electric, gas, insurance, telecommunications, and water industries for more than thirty years. He has testified on the cost of capital, competition, risk, incentive regulation, forward-looking economic cost, economic pricing guidelines, depreciation, accounting, valuation, and other financial and economic issues in more than 400 cases before the United States Congress, the Canadian Radio-Television and Telecommunications Commission, the Federal Communications Commission, the National Energy Board (Canada), the National Telecommunications and Information Administration, the Federal Energy Regulatory Commission, the public service commissions of 43 states, the District of Columbia, four Canadian provinces, the insurance commissions of five states, the Iowa State Board of Tax Review, the National Association of Securities Dealers, and the North Carolina Property Tax Commission. In addition, he has testified as an expert witness in proceedings before the United States District Court for the District of New Hampshire; United States District Court for the Northern District of California; United States District Court for the Northern District of Illinois, United States District Court for the District of Nebraska; United States District Court for the Eastern District of North Carolina; Superior Court of North Carolina, the United States Bankruptcy Court for the Southern District of West Virginia; and United States District Court for the Eastern District of Michigan. With respect to implementation of the Telecommunications Act of 1996, Dr. Vander Weide has testified in 30 states on issues relating to the pricing of unbundled network elements and universal service cost studies and has consulted with Bell Canada, Deutsche Telekom, and Telefónica on similar issues. He has also provided expert testimony on issues related to electric and natural gas restructuring. He has worked for Bell Canada/Nortel on a special task force to study the effects of vertical integration in the Canadian telephone industry and has worked for Bell Canada as an expert witness on the cost of capital. Dr. Vander Weide has provided consulting and expert witness testimony to the following companies:

ELECTRIC, GAS, WATER, OIL COMPANIES	
Alcoa Power Generating, Inc.	Maritimes & Northeast Pipeline
Alliant Energy and subsidiaries	MidAmerican Energy

ELECTRIC, GAS, WATER, OIL COMPANIES	
AltaLink, L.P.	Nevada Power Company
Ameren	NICOR
American Water Works	North Carolina Natural Gas
Atmos Energy and subsidiaries	North Shore Gas
BP p.l.c.	Northern Natural Gas Company
Central Illinois Public Service	NOVA Gas Transmission Ltd.
Citizens Utilities	PacifiCorp
Consolidated Natural Gas and subsidiaries	Peoples Energy and its subsidiaries
Dominion Resources and subsidiaries	PG&E
Duke Energy and subsidiaries	Progress Energy
Empire District Electric Company	PSE&G
EPCOR Distribution & Transmission Inc.	Public Service Company of North Carolina
EPCOR Energy Alberta Inc.	Sempra Energy/San Diego Gas and Electric
Fortis Inc. and subsidiaries	South Carolina Electric and Gas
Hope Natural Gas	Southern Company and subsidiaries
Interstate Power Company	Tennessee-American Water Company
Iowa Southern	The Peoples Gas, Light and Coke Co.
Iowa-American Water Company	TransCanada
Iowa-Illinois Gas and Electric	Trans Québec & Maritimes Pipeline Inc.
Kentucky Power Company	Union Gas
Kentucky-American Water Company	United Cities Gas Company
Kinder Morgan Energy Partners	Virginia-American Water Company

TELECOMMUNICATIONS COMPANIES	
ALLTEL and subsidiaries	Phillips County Cooperative Tel. Co.
Ameritech (now AT&T new)	Pine Drive Cooperative Telephone Co.
AT&T (old)	Roseville Telephone Company (SureWest)
Bell Canada/Nortel	SBC Communications (now AT&T new)
BellSouth and subsidiaries	Sherburne Telephone Company
Centel and subsidiaries	Siemens
Cincinnati Bell (Broadwing)	Southern New England Telephone
Cisco Systems	Sprint/United and subsidiaries
Citizens Telephone Company	Telefónica
Concord Telephone Company	Tellabs, Inc.
Contel and subsidiaries	The Stentor Companies

TELECOMMUNICATIONS COMPANIES	
Deutsche Telekom	U S West (Qwest)
GTE and subsidiaries (now Verizon)	Union Telephone Company
Heins Telephone Company	United States Telephone Association
JDS Uniphase	Valor Telecommunications (Windstream)
Lucent Technologies	Verizon (Bell Atlantic) and subsidiaries
Minnesota Independent Equal Access Corp.	Woodbury Telephone Company
NYNEX and subsidiaries (Verizon)	
Pacific Telesis and subsidiaries	

INSURANCE COMPANIES
Allstate
North Carolina Rate Bureau
United Services Automobile Association (USAA)
The Travelers Indemnity Company
Gulf Insurance Company

Other Professional Experience

Dr. Vander Weide conducts in-house seminars and training sessions on topics such as creating shareholder value, financial analysis, competitive strategy, cost of capital, real options, financial strategy, managing growth, mergers and acquisitions, valuation, measuring corporate performance, capital budgeting, cash management, and financial planning. Among the firms for whom he has designed and taught tailored programs and training sessions are ABB Asea Brown Boveri, Accenture, Allstate, Ameritech, AT&T, Bell Atlantic/Verizon, BellSouth, Progress Energy/Carolina Power & Light, Contel, Fisons, GlaxoSmithKline, GTE, Lafarge, Gulf Energy, New Century Energies, Norfolk Southern, Pacific Bell Telephone, The Rank Group, Siemens, Southern New England Telephone, TRW, and Wolseley Plc. Dr. Vander Weide has also hosted a nationally prominent conference/workshop on estimating the cost of capital. In 1989, at the request of Mr. Fuqua, Dr. Vander Weide designed the Duke Program for Manager Development for managers from the former Soviet Union, the first in the United States designed exclusively for managers from Russia and the former Soviet republics.

In the 1970's, Dr. Vander Weide helped found University Analytics, Inc., which at that time was one of the fastest growing small firms in the country. As an officer at University Analytics, he designed cash management models, databases, and software packages that are still used by most major U.S. banks in consulting with their corporate clients. Having sold his interest in University Analytics, Dr. Vander Weide now concentrates on strategic and financial consulting, academic research, and executive education.

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EXHIBIT JVW-2 APPENDIX 2
DERIVATION OF THE QUARTERLY DCF MODEL

The simple DCF Model assumes that a firm pays dividends only at the end of each year. Since firms in fact pay dividends quarterly and investors appreciate the time value of money, the annual version of the DCF Model generally underestimates the value investors are willing to place on the firm's expected future dividend stream. In these workpapers, we review two alternative formulations of the DCF Model that allow for the quarterly payment of dividends.

When dividends are assumed to be paid annually, the DCF Model suggests that the current price of the firm's stock is given by the expression:

$$P_0 = \frac{D_1}{(1+k)} + \frac{D_2}{(1+k)^2} + \cdots + \frac{D_n+P_n}{(1+k)^n} \qquad (1)$$

where

P_0	=	current price per share of the firm's stock,
$D_1, D_2,...,D_n$	=	expected annual dividends per share on the firm's stock,
P_n	=	price per share of stock at the time investors expect to sell the stock, and
k	=	return investors expect to earn on alternative investments of the same risk, i.e., the investors' required rate of return.

Unfortunately, expression (1) is rather difficult to analyze, especially for the purpose of estimating k. Thus, most analysts make a number of simplifying assumptions. First, they assume that dividends are expected to grow at the constant rate g into the indefinite future. Second, they assume that the stock price

at time n is simply the present value of all dividends expected in periods subsequent to n. Third, they assume that the investors' required rate of return, k, exceeds the expected dividend growth rate g. Under the above simplifying assumptions, a firm's stock price may be written as the following sum:

$$P_0 = \frac{D_0(1+g)}{(1+k)} + \frac{D_0(1+g)^2}{(1+k)^2} + \frac{D_0(1+g)^3}{(1+k)^3} + \cdots, \quad (2)$$

where the three dots indicate that the sum continues indefinitely.

As we shall demonstrate shortly, this sum may be simplified to:

$$P_0 = \frac{D_0(1+g)}{(k-g)}$$

First, however, we need to review the very useful concept of a geometric progression.

Geometric Progression

Consider the sequence of numbers 3, 6, 12, 24,..., where each number after the first is obtained by multiplying the preceding number by the factor 2. Obviously, this sequence of numbers may also be expressed as the sequence 3, 3 x 2, 3 x 2^2, 3 x 2^3, etc. This sequence is an example of a geometric progression.

Definition: A geometric progression is a sequence in which each term after the first is obtained by multiplying some fixed number, called the common ratio, by the preceding term.

A general notation for geometric progressions is: a, the first term, r, the common ratio, and n, the number of terms. Using this notation, any geometric progression may be represented by the sequence:

$$a, ar, ar^2, ar^3, \ldots, ar^{n-1}.$$

In studying the DCF Model, we will find it useful to have an expression for the sum of n terms of a geometric progression. Call this sum S_n. Then

$$S_n = a + ar + \cdots + ar^{n-1}. \quad (3)$$

However, this expression can be simplified by multiplying both sides of equation (3) by r and then subtracting the new equation from the old. Thus,

$$rS_n = ar + ar^2 + ar^3 + \ldots + ar^n$$

and

$$S_n - rS_n = a - ar^n ,$$

or

$$(1 - r)\, S_n = a\,(1 - r^n) .$$

Solving for S_n, we obtain:

$$S_n = \frac{a(1 - r^n)}{(1 - r)} \quad (4)$$

as a simple expression for the sum of n terms of a geometric progression. Furthermore, if $|r| < 1$, then S_n is finite, and as n approaches infinity, S_n approaches

a ÷ (1-r). Thus, for a geometric progression with an infinite number of terms and |r| < 1, equation (4) becomes:

$$S = \frac{a}{1-r} \qquad (5)$$

Application to DCF Model

Comparing equation (2) with equation (3), we see that the firm's stock price (under the DCF assumption) is the sum of an infinite geometric progression with the first term

$$a = \frac{D_0(1+g)}{(1+k)}$$

and common factor

$$r = \frac{(1+g)}{(1+k)}$$

Applying equation (5) for the sum of such a geometric progression, we obtain

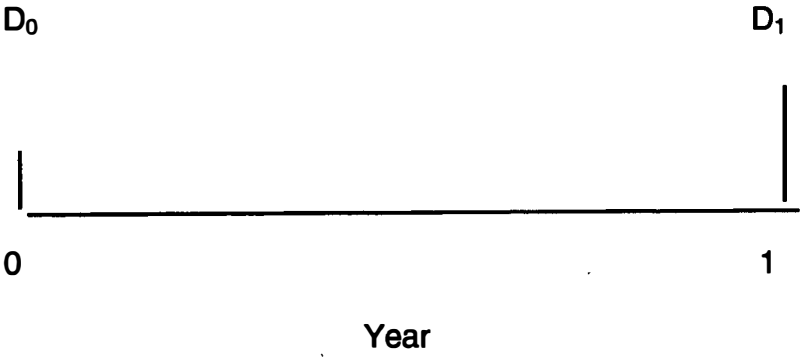
$$S = a \bullet \frac{1}{(1-r)} = \frac{D_0(1+g)}{(1+k)} \bullet \frac{1}{1-\frac{1+g}{1+k}} = \frac{D_0(1+g)}{(1+k)} \bullet \frac{1+k}{k-g} = \frac{D_0(1+g)}{k-g}$$

as we suggested earlier.

Quarterly DCF Model

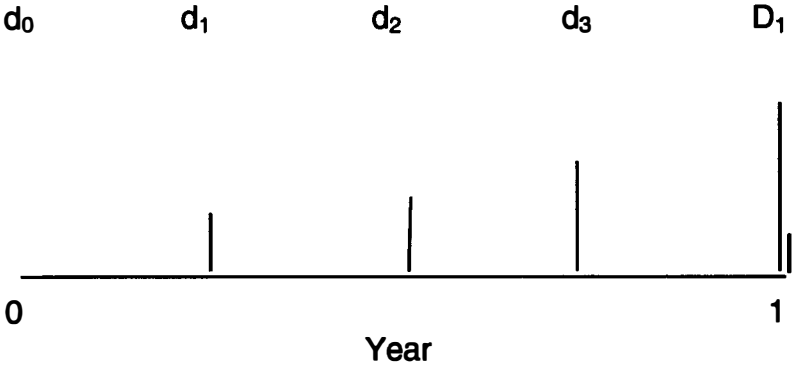
The Annual DCF Model assumes that dividends grow at an annual rate of g% per year (see Figure 1).

Figure 1
Annual DCF Model



$D_0 = 4d_0$ $D_1 = D_0(1 + g)$

Figure 2
Quarterly DCF Model (Constant Growth Version)



$d_1 = d_0(1+g)^{.25}$ $d_2 = d_0(1+g)^{.50}$

$d_3 = d_0(1+g)^{.75}$ $d_4 = d_0(1+g)$

In the Quarterly DCF Model, it is natural to assume that quarterly dividend payments differ from the preceding quarterly dividend by the factor $(1 + g)^{.25}$, where g is expressed in terms of percent per year and the decimal .25 indicates that the growth has only occurred for one quarter of the year. (See Figure 2.) Using this assumption, along with the assumption of constant growth and $k > g$, we obtain a new expression for the firm's stock price, which takes account of the quarterly payment of dividends. This expression is:

$$P_0 = \frac{d_0(1+g)^{1/4}}{(1+k)^{1/4}} + \frac{d_0(1+g)^{2/4}}{(1+k)^{2/4}} + \frac{d_0(1+g)^{3/4}}{(1+k)^{3/4}} + \cdots \qquad (6)$$

where d_0 is the last quarterly dividend payment, rather than the last annual dividend payment. (We use a lower case d to remind the reader that this is not the annual dividend.)

Although equation (6) looks formidable at first glance, it too can be greatly simplified using the formula [equation (4)] for the sum of an infinite geometric progression. As the reader can easily verify, equation (6) can be simplified to:

$$P_0 = \frac{d_0(1+g)^{\frac{1}{4}}}{(1+k)^{\frac{1}{4}} - (1+g)^{\frac{1}{4}}} \qquad (7)$$

Solving equation (7) for *k*, we obtain a DCF formula for estimating the cost of equity under the quarterly dividend assumption:

$$k = \left[\frac{d_0(1+g)^{\frac{1}{4}}}{P_0} + (1+g)^{\frac{1}{4}} \right]^4 - 1 \qquad \textbf{(8)}$$

An Altemative Quarterly DCF Model

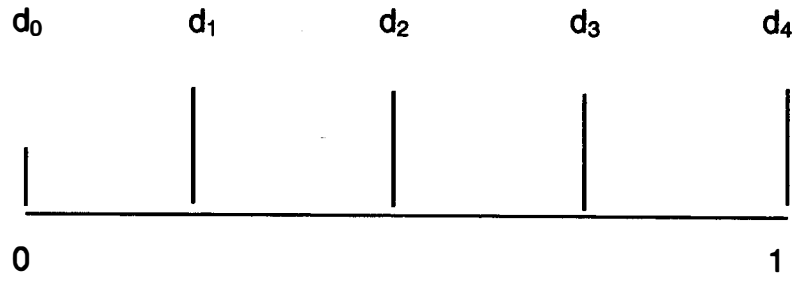
Although the constant growth Quarterly DCF Model [equation (8)] allows for the quarterly timing of dividend payments, it does require the assumption that the firm increases its dividend payments each quarter. Since this assumption is difficult for some analysts to accept, we now discuss a second Quarterly DCF Model that allows for constant quarterly dividend payments within each dividend year.

Assume then that the firm pays dividends quarterly and that each dividend payment is constant for four consecutive quarters. There are four cases to consider, with each case distinguished by varying assumptions about where we are evaluating the firm in relation to the time of its next dividend increase. (See Figure 3.)

Figure 3

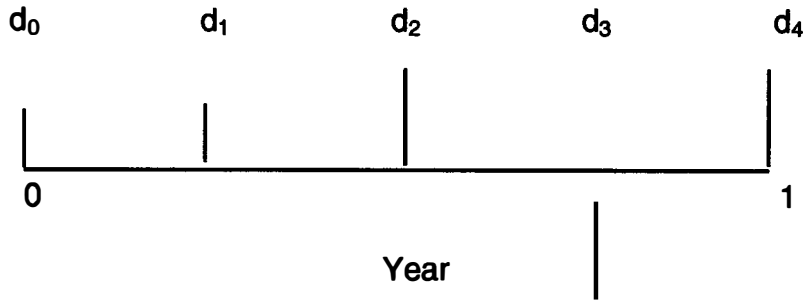
Quarterly DCF Model (Constant Dividend Version)

Case 1



$$d_1 = d_2 = d_3 = d_4 = d_0(1+g)$$

Case 2

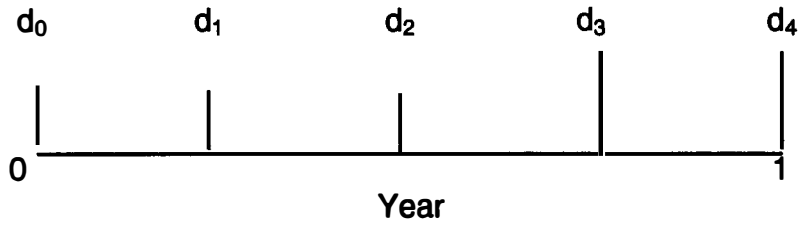


$$d_1 = d_0$$

$$d_2 = d_3 = d_4 = d_0(1+g)$$

Figure 3 (continued)

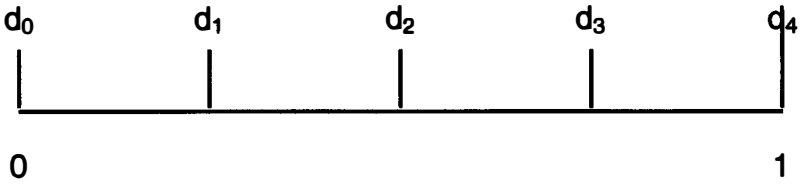
Case 3



$$d_1 = d_2 = d_0$$

$$d_3 = d_4 = d_0(1+g)$$

Case 4



$$d_1 = d_2 = d_3 = d_0$$

$$d_4 = d_0(1+g)$$

If we assume that the investor invests the quarterly dividend in an alternative investment of the same risk, then the amount accumulated by the end of the year will in all cases be given by

$$D_1^* = d_1 (1+k)^{3/4} + d_2 (1+k)^{1/2} + d_3 (1+k)^{1/4} + d_4$$

where d_1, d_2, d_3 and d_4 are the four quarterly dividends. Under these new assumptions, the firm's stock price may be expressed by an Annual DCF Model of the form (2), with the exception that

$$D_1^* = d_1 (1 + k)^{3/4} + d_2 (1 + k)^{1/2} + d_3 (1 + k)^{1/4} + d_4 \qquad \textbf{(9)}$$

is used in place of $D_0(1+g)$. But, we already know that the Annual DCF Model may be reduced to

$$P_0 = \frac{D_0(1+g)}{k-g}$$

Thus, under the assumptions of the second Quarterly DCF Model, the firm's cost of equity is given by

$$k = \frac{D_1^*}{P_0} + g \quad \textbf{(10)}$$

with D_1^* given by (9).

Although equation (10) looks like the Annual DCF Model, there are at least two very important practical differences. First, since D_1^* is always greater than $D_0(1+g)$, the estimates of the cost of equity are always larger (and more accurate) in the Quarterly Model (10) than in the Annual Model. Second, since D_1^* depends on k through equation (9), the unknown "k" appears on both sides of (10), and an iterative procedure is required to solve for k.

EXHIBIT JVW-2 APPENDIX 3
ADJUSTING FOR FLOTATION COSTS IN DETERMINING
A PUBLIC UTILITY'S ALLOWED RATE OF RETURN ON EQUITY

I. Introduction

Regulation of public utilities is guided by the principle that utility revenues should be sufficient to allow recovery of all prudently incurred expenses, including the cost of capital. As set forth in the 1944 *Hope Natural Gas* Case [*Federal Power Comm'n v. Hope Natural Gas Co.* 320 U. S. 591 (1944) at 603], the U. S. Supreme Court states:

> From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock....By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks.

Since the flotation costs arising from the issuance of debt and equity securities are an integral component of capital costs, this standard requires that the company's revenues be sufficient to fully recover flotation costs.

Despite the widespread agreement that flotation costs should be recovered in the regulatory process, several issues still need to be resolved. These include:

1. How is the term "flotation costs" defined? Does it include only the out-of-pocket costs associated with issuing securities (e. g., legal fees, printing costs, selling and underwriting expenses), or does it also include the reduction in a security's price that frequently accompanies flotation (i. e., market pressure)?
2. What should be the time pattern of cost recovery? Should a company be allowed to recover flotation costs immediately, or should flotation costs be recovered over the life of the issue?
3. For the purposes of regulatory accounting, should flotation costs be included as an expense? As an addition to rate base? Or as an additional element of a firm's allowed rate of return?

4. Do existing regulatory methods for flotation cost recovery allow a firm ***full*** recovery of flotation costs?

In this paper, I review the literature pertaining to the above issues and discuss my own views regarding how this literature applies to the cost of equity for a regulated firm.

I. Definition of Flotation Cost

The value of a firm is related to the future stream of net cash flows (revenues minus expenses measured on a cash basis) that can be derived from its assets. In the process of acquiring assets, a firm incurs certain expenses which reduce its value. Some of these expenses or costs are directly associated with revenue production in one period (e. g., wages, cost of goods sold), others are more properly associated with revenue production in many periods (e. g., the acquisition cost of plant and equipment). In either case, the word "cost" refers to any item that reduces the value of a firm.

If this concept is applied to the act of issuing new securities to finance asset purchases, many items are properly included in issuance or flotation costs. These include: (1) compensation received by investment bankers for underwriting services, (2) legal fees, (3) accounting fees, (4) engineering fees, (5) trustee's fees, (6) listing fees, (7) printing and engraving expenses, (8) SEC registration fees, (9) Federal Revenue Stamps, (10) state taxes, (11) warrants granted to underwriters as extra compensation, (12) postage expenses, (13) employees' time, (14) market pressure, and (15) the offer discount. The finance literature generally divides these flotation cost items into three categories, namely, underwriting expenses, issuer expenses, and price effects.

II. Magnitude of Flotation Costs

The finance literature contains several studies of the magnitude of the flotation costs associated with new debt and equity issues. These studies differ primarily with regard to the time period studied, the sample of companies included, and the source of data. The flotation cost studies generally agree, however, that for large issues, underwriting expenses represent approximately one and one-half percent of the proceeds of debt issues and three to five percent of the proceeds of seasoned equity issues. They also agree that issuer expenses represent approximately 0.5 percent of both debt and equity issues, and that the announcement of an equity issue reduces the company's stock price by at least two to three percent of the proceeds from the stock issue. Thus, total flotation

costs represent approximately two percent[1] of the proceeds from debt issues, and five and one-half to eight and one-half percent of the proceeds of equity issues.

Lee *et. al.* [14] is an excellent example of the type of flotation cost studies found in the finance literature. The Lee study is a comprehensive recent study of the underwriting and issuer costs associated with debt and equity issues for both utilities and non-utilities. The results of the Lee *et. al.* study are reproduced in Tables 1 and 2. Table 1 demonstrates that the total underwriting and issuer expenses for the 1,092 debt issues in their study averaged 2.24 percent of the proceeds of the issues, while the total underwriting and issuer costs for the 1,593 seasoned equity issues in their study averaged 7.11 percent of the proceeds of the new issue. Table 1 also demonstrates that the total underwriting and issuer costs of seasoned equity offerings, as a percent of proceeds, decline with the size of the issue. For issues above $60 million, total underwriting and issuer costs amount to from three to five percent of the amount of the proceeds.

Table 2 reports the total underwriting and issuer expenses for 135 utility debt issues and 136 seasoned utility equity issues. Total underwriting and issuer expenses for utility bond offerings averaged 1.47 percent of the amount of the proceeds and for seasoned utility equity offerings averaged 4.92 percent of the amount of the proceeds. Again, there are some economies of scale associated with larger equity offerings. Total underwriting and issuer expenses for equity offerings in excess of forty million dollars generally range from three to four percent of the proceeds.

The results of the Lee study for large equity issues are consistent with results of earlier studies by Bhagat and Frost [4], Mikkelson and Partch [17], and Smith [24]. Bhagat and Frost found that total underwriting and issuer expenses average approximately four and one-half percent of the amount of proceeds from negotiated utility offerings during the period 1973 to 1980, and approximately three and one-half percent of the amount of the proceeds from competitive utility offerings over the same period. Mikkelson and Partch found that total underwriting and issuer expenses average five and one-half percent of the proceeds from seasoned equity offerings over the 1972 to 1982 period. Smith found that total

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[1] The two percent flotation cost on debt only recognizes the cost of newly-issued debt. When interest rates decline, many companies exercise the call provisions on higher cost debt and reissue debt at lower rates. This process involves reacquisition costs that are not included in the academic studies. If reacquisition costs were included in the academic studies, debt flotation costs could increase significantly.

underwriting and issuer expenses for larger equity issues generally amount to four to five percent of the proceeds of the new issue.

The finance literature also contains numerous studies of the decline in price associated with sales of large blocks of stock to the public. These articles relate to the price impact of: (1) initial public offerings; (2) the sale of large blocks of stock from one investor to another; and (3) the issuance of seasoned equity issues to the general public. All of these studies generally support the notion that the announcement of the sale of large blocks of stock produces a decline in a company's share price. The decline in share price for initial public offerings is significantly larger than the decline in share price for seasoned equity offerings; and the decline in share price for public utilities is less than the decline in share price for non-public utilities. A comprehensive study of the magnitude of the decline in share price associated specifically with the sale of new equity by public utilities is reported in Pettway [19], who found the market pressure effect for a sample of 368 public utility equity sales to be in the range of two to three percent. This decline in price is a real cost to the utility, because the proceeds to the utility depend on the stock price on the day of issue.

In addition to the price decline associated with the announcement of a new equity issue, the finance literature recognizes that there is also a price decline associated with the actual issuance of equity securities. In particular, underwriters typically sell seasoned new equity securities to investors at a price lower than the closing market price on the day preceding the issue. The Rules of Fair Practice of the National Association of Securities Dealers require that underwriters not sell shares at a price above the offer price. Since the offer price represents a binding constraint to the underwriter, the underwriter tends to set the offer price slightly below the market price on the day of issue to compensate for the risk that the price received by the underwriter may go down, but can not increase. Smith provides evidence that the offer discount tends to be between 0.5 and 0.8 percent of the proceeds of an equity issue. I am not aware of any similar studies for debt issues.

In summary, the finance literature provides strong support for the conclusion that total underwriting and issuer expenses for public utility debt offerings represent approximately two percent of the amount of the proceeds, while total underwriting and issuer expenses for public utility equity offerings represent at least four to five percent of the amount of the proceeds. In addition, the finance literature supports the conclusion that the cost associated with the decline in stock price at the announcement date represents approximately two to three percent as a result of a large public utility equity issue.

III. Time Pattern Of Flotation Cost Recovery

Although flotation costs are incurred only at the time a firm issues new securities, there is no reason why an issuing firm ought to recognize the expense only in the current period. In fact, if assets purchased with the proceeds of a security issue produce revenues over many years, a sound argument can be made in favor of recognizing flotation expenses over a reasonably lengthy period of time. Such recognition is certainly consistent with the generally accepted accounting principle that the time pattern of expenses match the time pattern of revenues, and it is also consistent with the normal treatment of debt flotation expenses in both regulated and unregulated industries.

In the context of a regulated firm, it should be noted that there are many possible time patterns for the recovery of flotation expenses. However, if it is felt that flotation expenses are most appropriately recovered over a period of years, then it should be recognized that investors must also be compensated for the passage of time. That is to say, the value of an investor's capital will be reduced if the expenses are merely distributed over time, without any allowance for the time value of money.

IV. Accounting For Flotation Cost In A Regulatory Setting

In a regulatory setting, a firm's revenue requirements are determined by the equation:

Revenue Requirement = Total Expenses + Allowed Rate of Return x Rate Base

Thus, there are three ways in which an issuing firm can account for and recover its flotation expenses: (1) treat flotation expenses as a current expense and recover them immediately; (2) include flotation expenses in rate base and recover them over time; and (3) adjust the allowed rate of return upward and again recover flotation expenses over time. Before considering methods currently being used to recover flotation expenses in a regulatory setting, I shall briefly consider the advantages and disadvantages of these three basic recovery methods.

Expenses. Treating flotation costs as a current expense has several advantages. Because it allows for recovery at the time the expense occurs, it is not necessary to compute amortized balances over time and to debate which interest rate should be applied to these balances. A firm's stockholders are treated fairly, and so are the firm's customers, because they pay neither more nor less than the actual flotation expense. Since flotation costs are relatively small compared to the total

revenue requirement, treatment as a current expense does not cause unusual rate hikes in the year of flotation, as would the introduction of a large generating plant in a state that does not allow Construction Work in Progress in rate base.

On the other hand, there are two major disadvantages of treating flotation costs as a current expense. First, since the asset purchased with the acquired funds will likely generate revenues for many years into the future, it seems unfair that current ratepayers should bear the full cost of issuing new securities, when future ratepayers share in the benefits. Second, this method requires an estimate of the underpricing effect on each security issue. Given the difficulties involved in measuring the extent of underpricing, it may be more accurate to estimate the average underpricing allowance for many securities than to estimate the exact figure for one security.

Rate Base. In an article in *Public Utilities Fortnightly*, Bierman and Hass [5] recommend that flotation costs be treated as an intangible asset that is included in a firm's rate base along with the assets acquired with the stock proceeds. This approach has many advantages. For ratepayers, it provides a better match between benefits and expenses: the future ratepayers who benefit from the financing costs contribute the revenues to recover these costs. For investors, if the allowed rate of retum is equal to the investors' required rate of return, it is also theoretically fair since they are compensated for the opportunity cost of their investment (including both the time value of money and the investment risk).

Despite the compelling advantages of this method of cost recovery, there are several disadvantages that probably explain why it has not been used in practice. First, a firm will only recover the proper amount for flotation expenses if the rate base is multiplied by the appropriate cost of capital. To the extent that a commission under or over estimates the cost of capital, a firm will under or over recover its flotation expenses. Second, it is may be both legally and psychologically difficult for commissioners to include an intangible asset in a firm's rate base. According to established legal doctrine, assets are to be included in rate base only if they are "used and useful" in the public service. It is unclear whether intangible assets such as flotation expenses meet this criterion.

Rate of Return. The prevailing practice among state regulators is to treat flotation expenses as an additional element of a firm's cost of capital or allowed rate of return. This method is similar to the second method above (treatment in rate base) in that some part of the initial flotation cost is amortized over time. However, it has a disadvantage not shared by the rate base method. If flotation cost is included in

rate base, it is fairly easy to keep track of the flotation cost on each new equity issue and see how it is recovered over time. Using the rate of return method, it is not possible to track the flotation cost for specific issues because the flotation cost for a specific issue is never recorded. Thus, it is not clear to participants whether a current allowance is meant to recover (1) flotation costs actually incurred in a test period, (2) expected future flotation costs, or (3) past flotation costs. This confusion never arises in the treatment of debt flotation costs. Because the exact costs are recorded and explicitly amortized over time, participants recognize that current allowances for debt flotation costs are meant to recover some fraction of the flotation costs on all past debt issues.

V. Existing Regulatory Methods

Although most state commissions prefer to let a regulated firm recover flotation expenses through an adjustment to the allowed rate of return, there is considerable controversy about the magnitude of the required adjustment. The following are some of the most frequently asked questions: (1) Should an adjustment to the allowed return be made every year, or should the adjustment be made only in those years in which new equity is raised? (2) Should an adjusted rate of return be applied to the entire rate base, or should it be applied only to that portion of the rate base financed with paid-in capital (as opposed to retained earnings)? (3) What is the appropriate formula for adjusting the rate of return?

This section reviews several methods of allowing for flotation cost recovery. Since the regulatory methods of allowing for recovery of debt flotation costs is well known and widely accepted, I will begin my discussion of flotation cost recovery procedures by describing the widely accepted procedure of allowing for debt flotation cost recovery.

Debt Flotation Costs

Regulators uniformly recognize that companies incur flotation costs when they issue debt securities. They typically allow recovery of debt flotation costs by making an adjustment to both the cost of debt and the rate base (see Brigham [6]). Assume that: (1) a regulated company issues $100 million in bonds that mature in 10 years; (2) the interest rate on these bonds is seven percent; and (3) flotation costs represent four percent of the amount of the proceeds. Then the cost of debt for regulatory purposes will generally be calculated as follows:

$$\text{Cost of Debt} = \frac{\text{Interest expense} + \text{Amortization of flotation costs}}{\text{Principal value} - \text{Unamortized flotation costs}}$$
$$= \frac{\$7{,}000{,}000 + \$400{,}000}{\$100{,}000{,}000 - \$4{,}000{,}000}$$
$$= 7.71\%$$

Thus, current regulatory practice requires that the cost of debt be adjusted upward by approximately 71 basis points, in this example, to allow for the recovery of debt flotation costs. This example does not include losses on reacquisition of debt. The flotation cost allowance would increase if losses on reacquisition of debt were included.

The logic behind the traditional method of allowing for recovery of debt flotation costs is simple. Although the company has issued $100 million in bonds, it can only invest $96 million in rate base because flotation costs have reduced the amount of funds received by $4 million. If the company is not allowed to earn a 71 basis point higher rate of return on the $96 million invested in rate base, it will not generate sufficient cash flow to pay the seven percent interest on the $100 million in bonds it has issued. Thus, proper regulatory treatment is to increase the required rate of return on debt by 71 basis points.

Equity Flotation Costs

The finance literature discusses several methods of recovering equity flotation costs. Since each method stems from a specific model, (i. e., set of assumptions) of a firm and its cash flows, I will highlight the assumptions that distinguish one method from another.

Arzac and Marcus. Arzac and Marcus [2] study the proper flotation cost adjustment formula for a firm that makes continuous use of retained earnings and external equity financing and maintains a constant capital structure (debt/equity ratio). They assume at the outset that underwriting expenses and underpricing apply only to new equity obtained from external sources. They also assume that a firm has previously recovered all underwriting expenses, issuer expenses, and underpricing associated with previous issues of new equity.

To discuss and compare various equity flotation cost adjustment formulas, Arzac and Marcus make use of the following notation:

k = an investors' required return on equity

r	=	a utility's allowed return on equity base
S	=	value of equity in the absence of flotation costs
S_f	=	value of equity net of flotation costs
K_t	=	equity base at time t
E_t	=	total earnings in year t
D_t	=	total cash dividends at time t
b	=	$(E_t - D_t) \div E_t$ = retention rate, expressed as a fraction of earnings
h	=	new equity issues, expressed as a fraction of earnings
m	=	equity investment rate, expressed as a fraction of earnings, $m = b + h < 1$
f	=	flotation costs, expressed as a fraction of the value of an issue.

Because of flotation costs, Arzac and Marcus assume that a firm must issue a greater amount of external equity each year than it actually needs. In terms of the above notation, a firm issues $hE_t \div (1-f)$ to obtain hE_t in external equity funding. Thus, each year a firm loses:

Equation 1

$$L = \frac{hE_t}{1-f} - hE_t = \frac{f}{1-f} \times hE_t$$

due to flotation expenses. The present value, V, of all future flotation expenses is:

Equation 2

$$V = \sum_{t=1}^{\infty} \frac{fhE_t}{(1-f)(1+k)^t} = \frac{fh}{1-f} \times \frac{rK_0}{k-mr}$$

To avoid diluting the value of the initial stockholder's equity, a regulatory authority needs to find the value of r, a firm's allowed return on equity base, that equates the

value of equity net of flotation costs to the initial equity base ($S_f = K_0$). Since the value of equity net of flotation costs equals the value of equity in the absence of flotation costs minus the present value of flotation costs, a regulatory authority needs to find that value of *r* that solves the following equation:

$$S_f = S - L.$$

This value is:

Equation 3

$$r = \frac{k}{1 - \frac{fh}{1-f}}$$

To illustrate the Arzac-Marcus approach to adjusting the allowed return on equity for the effect of flotation costs, suppose that the cost of equity in the absence of flotation costs is 12 percent. Furthermore, assume that a firm obtains external equity financing each year equal to 10 percent of its earnings and that flotation expenses equal 5 percent of the value of each issue. Then, according to Arzac and Marcus, the allowed return on equity should be:

$$r = \frac{.12}{1 - \frac{(.05).(.1)}{.95}} = .1206 = 12.06\%$$

Summary. With respect to the three questions raised at the beginning of this section, it is evident that Arzac and Marcus believe the flotation cost adjustment should be applied each year, since continuous external equity financing is a fundamental assumption of their model. They also believe that the adjusted rate of return should be applied to the entire equity-financed portion of the rate base because their model is based on the assumption that the flotation cost adjustment mechanism will be applied to the entire equity financed portion of the rate base. Finally, Arzac and Marcus recommend a flotation cost adjustment formula, Equation (3), that implicitly excludes recovery of financing costs associated with financing in previous periods and includes only an allowance for the fraction of equity financing obtained from external sources.

Patterson. The Arzac-Marcus flotation cost adjustment formula is significantly different from the conventional approach (found in many introductory textbooks) which recommends the adjustment equation:

Equation 4

$$r = \frac{D_t}{P_{t-1}(1-f)} + g$$

where P_{t-1} is the stock price in the previous period and g is the expected dividend growth rate. Patterson [18] compares the Arzac-Marcus adjustment formula to the conventional approach and reaches the conclusion that the Arzac-Marcus formula effectively expenses issuance costs as they are incurred, while the conventional approach effectively amortizes them over an assumed infinite life of the equity issue. Thus, the conventional formula is similar to the formula for the recovery of debt flotation costs: it is not meant to compensate investors for the flotation costs of future issues, but instead is meant to compensate investors for the flotation costs of previous issues. Patterson argues that the conventional approach is more appropriate for rate making purposes because the plant purchased with external equity funds will yield benefits over many future periods.

Illustration. To illustrate the Patterson approach to flotation cost recovery, assume that a newly organized utility sells an initial issue of stock for $100 per share, and that the utility plans to finance all new investments with retained earnings. Assume also that: (1) the initial dividend per share is six dollars; (2) the expected long-run dividend growth rate is six percent; (3) the flotation cost is five percent of the amount of the proceeds; and (4) the payout ratio is 51.28 percent. Then, the investor's required rate of return on equity is [k = (D/P) + g = 6 percent + 6 percent = 12 percent]; and the flotation-cost-adjusted cost of equity is [6 percent (1/.95) + 6 percent = 12.316 percent].

The effects of the Patterson adjustment formula on the utility's rate base, dividends, earnings, and stock price are shown in Table 3. We see that the Patterson formula allows earnings and dividends to grow at the expected six percent rate. We also see that the present value of expected future dividends, $100, is just sufficient to induce investors to part with their money. If the present value of expected future dividends were less than $100, investors would not have been willing to invest $100 in the firm. Furthermore, the present value of future dividends will only equal $100 if the firm is allowed to eam the 12.316 percent flotation-cost-adjusted cost of equity on its entire rate base.

Summary. Patterson's opinions on the three issues raised in this section are in stark contrast to those of Arzac and Marcus. He believes that: (1) a flotation cost adjustment should be applied in every year, regardless of whether a firm issues

any new equity in each year; (2) a flotation cost adjustment should be applied to the entire equity-financed portion of the rate base, including that portion financed by retained earnings; and (3) the rate of return adjustment formula should allow a firm to recover an appropriate fraction of all previous flotation expenses.

VI. Conclusion

Having reviewed the literature and analyzed flotation cost issues, I conclude that:

Definition of Flotation Cost: A regulated firm should be allowed to recover both the total underwriting and issuance expenses associated with issuing securities and the cost of market pressure.

Time Pattern of Flotation Cost Recovery. Shareholders are indifferent between the alternatives of immediate recovery of flotation costs and recovery over time, as long as they are fairly compensated for the opportunity cost of their money. This opportunity cost must include both the time value of money and a risk premium for equity investments of this nature.

Regulatory Recovery of Flotation Costs. The Patterson approach to recovering flotation costs is the only rate-of-return-adjustment approach that meets the *Hope* case criterion that a regulated company's revenues must be sufficient to allow the company an opportunity to recover all prudently incurred expenses, including the cost of capital. The Patterson approach is also the only rate-of-return-adjustment approach that provides an incentive for investors to invest in the regulated company.

Implementation of a Flotation Cost Adjustment. As noted earlier, prevailing regulatory practice seems to be to allow the recovery of flotation costs through an adjustment to the required rate of return. My review of the literature on this subject indicates that there are at least two recommended methods of making this adjustment: the Patterson approach and the Arzac-Marcus approach. The Patterson approach assumes that a firm's flotation expenses on new equity issues are treated in the same manner as flotation expenses on new bond issues, i. e., they are amortized over future time periods. If this assumption is true (and I believe it is), then the flotation cost adjustment should be applied to a firm's entire equity base, including retained earnings. In practical terms, the Patterson approach produces an increase in a firm's cost of equity of approximately thirty basis points. The Arzac-Marcus approach assumes that flotation costs on new equity issues are recovered entirely in the year in which the securities are sold. Under the Arzac-Marcus assumption, a firm should not be allowed any adjustments for flotation

costs associated with previous flotations. Instead, a firm should be allowed only an adjustment on future security sales as they occur. Under reasonable assumptions about the rate of new equity sales, this method produces an increase in the cost of equity of approximately six basis points. Since the Arzac-Marcus approach does not allow the company to recover the entire amount of its flotation cost, I recommend that this approach be rejected and the Patterson approach be accepted.

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Table 1
Direct Costs as a Percentage of Gross Proceeds
for Equity (IPOs and SEOs) and Straight and Convertible Bonds
Offered by Domestic Operating Companies 1990—1994[2]

Equities

		IPOs				SEOs			
Line No.	Proceeds ($ in millions)	No. of Issues	Gross Spreads	Other Direct Expenses	Total Direct Costs	No. of Issues	Gross Spreads	Other Direct Expenses	Total Direct Costs
1	2-9.99	337	9.05%	7.91%	16.96%	167	7.72%	5.56%	13.28%
2	10-19.99	389	7.24%	4.39%	11.63%	310	6.23%	2.49%	8.72%
3	20-39.99	533	7.01%	2.69%	9.70%	425	5.60%	1.33%	6.93%
4	40-59.99	215	6.96%	1.76%	8.72%	261	5.05%	0.82%	5.87%
5	60-79.99	79	6.74%	1.46%	8.20%	143	4.57%	0.61%	5.18%
6	80-99.99	51	6.47%	1.44%	7.91%	71	4.25%	0.48%	4.73%
7	100-199.99	106	6.03%	1.03%	7.06%	152	3.85%	0.37%	4.22%
8	200-499.99	47	5.67%	0.86%	6.53%	55	3.26%	0.21%	3.47%
9	500 and up	10	5.21%	0.51%	5.72%	9	3.03%	0.12%	3.15%
10	**Total/Average**	**1,767**	**7.31%**	**3.69%**	**11.00%**	**1,593**	**5.44%**	**1.67%**	**7.11%**

Bonds

		Convertible Bonds				Straight Bonds			
Line No.	Proceeds ($ in millions)	No. of Issues	Gross Spreads	Other Direct Expenses	Total Direct Costs	No. of Issues	Gross Spreads	Other Direct Expenses	Total Direct Costs
1	2-9.99	4	6.07%	2.68%	8.75%	32	2.07%	2.32%	4.39%
2	10-19.99	14	5.48%	3.18%	8.66%	78	1.36%	1.40%	2.76%
3	20-39.99	18	4.16%	1.95%	6.11%	89	1.54%	0.88%	2.42%
4	40-59.99	28	3.26%	1.04%	4.30%	90	0.72%	0.60%	1.32%
5	60-79.99	47	2.64%	0.59%	3.23%	92	1.76%	0.58%	2.34%
6	80-99.99	13	2.43%	0.61%	3.04%	112	1.55%	0.61%	2.16%
7	100-199.99	57	2.34%	0.42%	2.76%	409	1.77%	0.54%	2.31%
8	200-499.99	27	1.99%	0.19%	2.18%	170	1.79%	0.40%	2.19%
9	500 and up	3	2.00%	0.09%	2.09%	20	1.39%	0.25%	1.64%
10	**Total/Average**	**211**	**2.92%**	**0.87%**	**3.79%**	**1,092**	**1.62%**	**0.62%**	**2.24%**

[2] Inmoo Lee, Scott Lochhead, Jay Ritter, and Quanshui Zhao, "The Costs of Raising Capital," *Journal of Financial Research* Vol 19 No 1 (Spring 1996) pp. 59-74.

Notes:

Closed-end funds and unit offerings are excluded from the sample. Rights offerings for SEOs are also excluded. Bond offerings do not include securities backed by mortgages and issues by Federal agencies. Only firm commitment offerings and non-shelf-registered offerings are included.
Gross Spreads as a percentage of total proceeds, including management fee, underwriting fee, and selling concession.
Other Direct Expenses as a percentage of total proceeds, including management fee, underwriting fee, and selling concession.
Total Direct Costs as a percentage of total proceeds (total direct costs are the sum of gross spreads and other direct expenses).

Table 2
Direct Costs of Raising Capital 1990—1994
Utility versus Non-Utility Companies[3]

Equities

	Non-Utilities	IPOs			SEOs		
Line No.	Proceeds ($ in millions)	No. of Issues	Gross Spreads	Total Direct Costs	No. Of Issues	Gross Spreads	Total Direct Costs
1	2-9.99	332	9.04%	16.97%	154	7.91%	13.76%
2	10-19.99	388	7.24%	11.64%	278	6.42%	9.01%
3	20-39.99	528	7.01%	9.70%	399	5.70%	7.07%
4	40-59.99	214	6.96%	8.71%	240	5.17%	6.02%
5	60-79.99	78	6.74%	8.21%	131	4.68%	5.31%
6	80-99.99	47	6.46%	7.88%	60	4.35%	4.84%
7	100-199.99	101	6.01%	7.01%	137	3.97%	4.36%
8	200-499.99	44	5.65%	6.49%	50	3.27%	3.48%
9	500 and up	10	5.21%	5.72%	8	3.12%	3.25%
10	**Total/Average**	1,742	7.31%	11.01%	1,457	5.57%	7.32%
11	**Utilities Only**						
12	2-9.99	5	9.40%	16.54%	13	5.41%	7.68%
13	10-19.99	1	7.00%	8.77%	32	4.59%	6.21%
14	20-39.99	5	7.00%	9.86%	26	4.17%	4.96%
15	40-59.99	1	6.98%	11.55%	21	3.69%	4.12%
16	60-79.99	1	6.50%	7.55%	12	3.39%	3.72%
17	80-99.99	4	6.57%	8.24%	11	3.68%	4.11%
18	100-199.99	5	6.45%	7.96%	15	2.83%	2.98%
19	200-499.99	3	5.88%	7.00%	5	3.19%	3.48%
20	500 and up	0			1	2.25%	2.31%
21	**Total/Average**	25	7.15%	10.14%	136	4.01%	4.92%

[3] Lee *et al, op. cit.*

Table 2 (continued)
Direct Costs of Raising Capital 1990—1994
Utility versus Non-Utility Companies[4]

Bonds

	Non- Utilities	Convertible Bonds			Straight Bonds		
Line No.	Proceeds ($ in millions)	No. of Issues	Gross Spreads	Total Direct Costs	No. of Issues	Gross Spreads	Total Direct Costs
1	2-9.99	4	6.07%	8.75%	29	2.07%	4.53%
2	10-19.99	12	5.54%	8.65%	47	1.70%	3.28%
3	20-39.99	16	4.20%	6.23%	63	1.59%	2.52%
4	40-59.99	28	3.26%	4.30%	76	0.73%	1.37%
5	60-79.99	47	2.64%	3.23%	84	1.84%	2.44%
6	80-99.99	12	2.54%	3.19%	104	1.61%	2.25%
7	100-199.99	55	2.34%	2.77%	381	1.83%	2.38%
8	200-499.99	26	1.97%	2.16%	154	1.87%	2.27%
9	500 and up	3	2.00%	2.09%	19	1.28%	1.53%
10	**Total/Average**	203	2.90%	3.75%	957	1.70%	2.34%
11	**Utilities Only**						
12	2-9.99	0			3	2.00%	3.28%
13	10-19.99	2	5.13%	8.72%	31	0.86%	1.35%
14	20-39.99	2	3.88%	5.18%	26	1.40%	2.06%
15	40-59.99	0			14	0.63%	1.10%
16	60-79.99	0			8	0.87%	1.13%
17	80-99.99	1	1.13%	1.34%	8	0.71%	0.98%
18	100-199.99	2	2.50%	2.74%	28	1.06%	1.42%
19	200-499.99	1	2.50%	2.65%	16	1.00%	1.40%
20	500 and up	0			1	3.50%	na[5]
21	**Total/Average**	8	3.33%	4.66%	135	1.04%	1.47%

Notes:
Total proceeds raised in the United States, excluding proceeds from the exercise of over allotment options.
Gross spreads as a percentage of total proceeds (including management fee, underwriting fee, and selling concession).
Other direct expenses as a percentage of total proceeds (including registration fee and printing, legal, and auditing costs).

[4] Lee *et al, op. cit.*

[5] Not available because of missing data on other direct expenses.

Table 3
Illustration of Patterson Approach to Flotation Cost Recovery

Line No.	Time Period	Rate Base	Earnings @ 12.32%	Earnings @ 12.00%	Dividends	Amortization Initial FC
1	0	95.00				
2	1	100.70	11.70	11.40	6.00	0.3000
3	2	106.74	12.40	12.08	6.36	0.3180
4	3	113.15	13.15	12.81	6.74	0.3371
5	4	119.94	13.93	13.58	7.15	0.3573
6	5	127.13	14.77	14.39	7.57	0.3787
7	6	134.76	15.66	15.26	8.03	0.4015
8	7	142.84	16.60	16.17	8.51	0.4256
9	8	151.42	17.59	17.14	9.02	0.4511
10	9	160.50	18.65	18.17	9.56	0.4782
11	10	170.13	19.77	19.26	10.14	0.5068
12	11	180.34	20.95	20.42	10.75	0.5373
13	12	191.16	22.21	21.64	11.39	0.5695
14	13	202.63	23.54	22.94	12.07	0.6037
15	14	214.79	24.96	24.32	12.80	0.6399
16	15	227.67	26.45	25.77	13.57	0.6783
17	16	241.33	28.04	27.32	14.38	0.7190
18	17	255.81	29.72	28.96	15.24	0.7621
19	18	271.16	31.51	30.70	16.16	0.8078
20	19	287.43	33.40	32.54	17.13	0.8563
21	20	304.68	35.40	34.49	18.15	0.9077
22	21	322.96	37.52	36.56	19.24	0.9621
23	22	342.34	39.77	38.76	20.40	1.0199
24	23	362.88	42.16	41.08	21.62	1.0811
25	24	384.65	44.69	43.55	22.92	1.1459
26	25	407.73	47.37	46.16	24.29	1.2147
27	26	432.19	50.21	48.93	25.75	1.2876
28	27	458.12	53.23	51.86	27.30	1.3648
29	28	485.61	56.42	54.97	28.93	1.4467
30	29	514.75	59.81	58.27	30.67	1.5335
31	30	545.63	63.40	61.77	32.51	1.6255
32	Present Value@12%		195.00	190.00	100.00	5.00

EXHIBIT JVW-2 APPENDIX 4
EX ANTE RISK PREMIUM APPROACH

My ex ante risk premium method is based on studies of the DCF expected return on proxy companies compared to the interest rate on Moody's A-rated utility bonds. Specifically, for each month in my study period, I calculate the risk premium using the equation,

$$RP_{PROXY} = DCF_{PROXY} - I_A$$

where:

RP_{PROXY} = the required risk premium on an equity investment in the proxy group of companies,

DCF_{PROXY} = average DCF estimated cost of equity on a portfolio of proxy companies; and

I_A = the yield to maturity on an investment in A-rated utility bonds.

Electric Utility Ex Ante Risk Premium Analysis. For my ex ante risk premium electric proxy group DCF analysis, I begin with the Moody's group of twenty-four electric utilities shown in Table 1. I use the Moody's group of electric utilities because they are a widely followed group of electric utilities, and use of this constant group greatly simplified the data collection task required to estimate the ex ante risk premium over the months of my study. Simplifying the data collection task is desirable because the ex ante risk premium approach requires that the DCF model be estimated for every company in every month of the study period. The Ex Ante Risk Premium exhibit in my direct testimony displays the average DCF estimated cost of equity on an investment in the portfolio of electric utilities and the yield to maturity on A-rated utility bonds in each month of the study.

Previous studies have shown that the ex ante risk premium tends to vary inversely with the level of interest rates, that is, the risk premium tends to increase

when interest rates decline, and decrease when interest rates go up. To test whether my studies also indicate that the ex ante risk premium varies inversely with the level of interest rates, I performed a regression analysis of the relationship between the ex ante risk premium and the yield to maturity on A-rated utility bonds, using the equation,

$$RP_{PROXY} = a + (b \times I_A) + e$$

where:

RP_{PROXY} = risk premium on proxy company group;

I_A = yield to maturity on A-rated utility bonds;

e = a random residual; and

a, b = coefficients estimated by the regression procedure.

Regression analysis assumes that the statistical residuals from the regression equation are random. My examination of the residuals revealed that there is a significant probability that the residuals are serially correlated (non-zero serial correlation indicates that the residual in one time period tends to be correlated with the residual in the previous time period). Therefore, I made adjustments to my data to correct for the possibility of serial correlation in the residuals.

The common procedure for dealing with serial correlation in the residuals is to estimate the regression coefficients in two steps. First, a multiple regression analysis is used to estimate the serial correlation coefficient, *r*. Second, the estimated serial correlation coefficient is used to transform the original variables into new variables whose serial correlation is approximately zero. The regression coefficients are then re-estimated using the transformed variables as inputs in the regression equation. Based on my knowledge of the statistical relationship between the yield to maturity on A-rated utility bonds and the required risk premium, my estimate of the ex ante risk premium on an investment in my proxy

electric company group as compared to an investment in A-rated utility bonds is given by the equation:

RP_{PROXY}	=	8.18 -	.543 x I_A.
T-statistic	=	(11.11)	(-4.89)

Using the forecast 6.55 percent yield to maturity on A-rated utility bonds, the regression equation produces an ex ante risk premium based on the electric proxy group equal to 4.62 percent (8.18 – .543 x 6.55 = 4.62).

To estimate the cost of equity using the ex ante risk premium method, one may add the estimated risk premium over the yield on A-rated utility bonds to the yield to maturity on A-rated utility bonds. The forecast yield on A-rated utility bonds is 6.55percent. As noted above, my analyses produce an estimated risk premium over the yield on A-rated utility bonds equal to 4.62 percent. Adding an estimated risk premium of 4.62 percent to the 6.55 percent average yield to maturity on A-rated utility bonds produces a cost of equity estimate of 11.2 percent for the electric company proxy group using the ex ante risk premium method.

TABLE 1
MOODY'S ELECTRIC UTILITIES

American Electric Power
Constellation Energy
Progress Energy
CH Energy Group
Cinergy Corp.
Consolidated Edison Inc.
DPL Inc.
DTE Energy Co.
Dominion Resources Inc.
Duke Energy Corp.
Energy East Corp.
FirstEnergy Corp.
Reliant Energy Inc.
IDACORP. Inc.
IPALCO Enterprises Inc.
NiSource Inc.
OGE Energy Corp.
Exelon Corp.
PPL Corp.
Potomac Electric Power Co.
Public Service Enterprise Group
Southern Company
Teco Energy Inc.
Xcel Energy Inc.

Source of data: *Mergent Public Utility Manual*, August 2002. Of these twenty-four companies, I do not include companies in my ex ante risk premium DCF analysis in months in which there are insufficient data to perform a DCF analysis. In addition, since the beginning period of my study, companies have been eliminated due to mergers and acquisitions.

EXHIBIT JVW-2 APPENDIX 5
EX POST RISK PREMIUM APPROACH

Source

Stock price and yield information is obtained from Standard & Poor's Security Price publication. Standard & Poor's derives the stock dividend yield by dividing the aggregate cash dividends (based on the latest known annual rate) by the aggregate market value of the stocks in the group. The bond price information is obtained by calculating the present value of a bond due in thirty years with a $4.00 coupon and a yield to maturity of a particular year's indicated Moody's A-rated utility bond yield. The values shown in the schedules are the January values of the respective indices.

Calculation of Stock and Bond Returns

Sample calculation of "Stock Return" column:

$$\text{Stock Return (2012)} = \left[\frac{\text{Stock Price (2013)} - \text{Stock Price (2012)} + \text{Dividend (2012)}}{\text{Stock Price (2012)}}\right]$$

where Dividend (2012) = Stock Price (2012) x Stock Div. Yield (2012)

Sample calculation of "Bond Return" column:

$$\text{Bond Return (2012)} = \left[\frac{\text{Bond Price (2013)} - \text{Bond Price (2012)} + \text{Interest (2012)}}{\text{Bond Price (2012)}}\right]$$

where Interest = $4.00.

Gulf's Total Package of Compensation and Benefits Aligns with Fundamental Beliefs

Fundamental Beliefs	Compensation Plan	Health Benefits Plan	Retirement Plans (Pension, 401k, Retiree Medical)	Other Benefits Plans (Life and Disability Insurance Plans)
1. Long-Term Customer Value is Created Through Retaining Employees	Secondary	Secondary	Primary	Primary
2. Health and Wellbeing of the Workforce Improves Productivity	NA	Primary	Secondary	Secondary
3. Linking Pay to Performance Efficiently and Economically Aligns Employee and Customer Interests	Primary	NA	NA	NA
4. Compensation and Benefit Program Competitiveness is Critical	• Annually review against the market for alignment • Annually review against the market for competitiveness			

Primary represents a primary focus of plan design
Secondary represents a secondary focus of plan design

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130140-EI EXHIBIT 16
PARTY Gulf Power Company (Gulf) Direct
DESCRIPTION James M. Garvie (JMG-1)
DATE

Gulf Power Company
Base Salary and Total Compensation to Market Median

	Gulf Base Salary to Market Median Base Salary	Gulf Total Compensation to Market Median Total Compensation
Gulf Power Company	-1.6%	-0.4%

Notes: 1. Total Compensation includes base salary plus at-risk (variable) compensation.

2. Data does not include employees and positions covered by a collective bargaining unit since base salary wages are negotiated.

TOWERS WATSON

Memorandum

Date:	June 13, 2013
To:	Jeffrey A. Stone, Esq. — Beggs & Lane
From:	David Wathen — Towers Watson/Atlanta Kevin Stiefler — Towers Watson/Atlanta
Subject:	Audit of Gulf Power's Pay Programs

Gulf Power Company (Gulf Power) is filing a request with the Florida Public Service Commission (FPSC) for a base rate adjustment. In preparation for this request, Gulf Power asked Towers Watson to review the competitiveness of its current pay programs relative to utility industry market practices.

In performing this review, Towers Watson analyzed the following plans, programs and processes for Gulf Power:

- Pay philosophy
- Annual merit increases
- Pay benchmark process
- Competitive market positioning of total pay (base salary and at-risk pay)
- At-risk pay programs
  - Performance Pay Program – the company's annual at-risk pay program
  - Stock Option and Performance Shares – the company's long-term at-risk pay programs

Summary Findings

Based on our review, we find:

- Gulf Power's total pay philosophy of targeting the 50th percentile of similarly sized utilities is consistent with the majority of utility peer companies examined and our consulting experience suggests it is the most prevalent practice across general industry

- Historical merit increases at Gulf Power have typically been below market levels over the last 13 years

- Gulf Power's pay benchmarking process is consistent with utility industry and general industry market best practices

- When compared to available published survey data, Gulf Power's pay levels are competitive with market levels based on the company's stated pay philosophy for base salary and target total direct compensation (Target TDC = base salary + at-risk pay)

- Gulf Power's strategy to provide at-risk pay (both annual and long-term) is consistent with the majority of publicly-traded utility peers examined. While specific design elements of at-risk pay programs may differ among utility peers, Gulf Power's design differences are limited. Overall, we find the

Company's at-risk pay program designs to be comparable to and competitive with designs of utility peers

- Based upon our review, we find Gulf Power's overall pay plans, programs and processes to be comparable to and competitive with utility peer practices

Pay Philosophy

Gulf Power's pay philosophy is to target base salary, annual at-risk and long-term at-risk pay at the 50th percentile of similarly sized utilities.

Towers Watson reviewed current proxy disclosures for the following two market perspectives to assess how Gulf Power's pay philosophy compares to market practice:

- Large Utility Peer Group – 15 publicly-traded, comparably-sized electric utilities with revenues in a range of approximately ½ to 2 times the revenues of Southern Company (see Exhibit 1 for the list of Large Utility Peer Companies)

- Small Utility Peer Group – Since comparably-sized subsidiary utilities like Gulf Power do not generally disclose pay program data, a peer group of 15 publicly-traded, comparably-sized electric utilities with revenues in a range of ½ to 2 times the revenues of Gulf Power were used for comparison (see Exhibit 2 for the list of Small Utility Peer Companies)

When developing peer groups for comparison, assessing companies with revenues in a range of ½ to 2 times company revenues is standard practice in compensation consulting and is also a guideline utilized by Institutional Shareholder Services (ISS), a prominent proxy advisor firm.

Pay Philosophy Review Findings

Based on our review, Gulf Power's pay philosophy aligns well with both market perspectives. Most peers (14 of the 15 Large Utility Peer Group and 14 of the 15 Small Utility Peer Group) target the market 50th percentile for some or all pay elements. For those companies that do not target the market 50th percentile, 1 small utility does not disclose a pay philosophy and 1 large utility targets the market 75th percentile for selected roles/critical positions. Likewise, Gulf Power's target pay positioning of the market 50th percentile aligns with the more common market practice found in the general industry.

Annual Merit Increases

Towers Watson was provided the actual average merit increase rates provided to all employees at Gulf Power from 2001 to 2013.

The WorldatWork Salary Budget Survey (a nationally renowned salary budget survey) was used by Towers Watson to assess the competitiveness of base salary merit increases at Gulf Power. The competitiveness of Gulf Power's merit increases were determined by using both the utility and general industry data cuts available in the WoldatWork survey.

The table shown below identifies the actual average base salary merit increase provided to all employees at Gulf Power and compares this to the median total salary budget increases for all employees using the utility and general industry data from the WorldatWork survey.

Year	Gulf Power Average Increase as % of salary	Utility Median Actual Salary Budget Increase	General Industry Median Actual Salary Budget Increase
2013	2.8%	3.0%[1]	3.0%[1]
2012	2.9%	2.9%	3.0%
2011	2.6%	3.0%	3.0%
2010	2.7%	2.8%	2.7%
2009	0.0%	3.0%	2.5%
2008	3.5%	4.1%	3.9%
2007	3.3%	3.7%	3.9%
2006	3.4%	3.8%	3.8%
2005	3.3%	3.6%	3.7%
2004	3.1%	3.4%	3.6%
2003	3.7%	3.3%	3.6%
2002	3.9%	3.8%	3.9%
2001	4.2%	4.4%	4.6%

[1]Market data represents projected salary budget increases.

Overall, Gulf Power's historical merit increases have typically been at or below market levels for 11 of the last 13 years compared to other utilities and 12 of the last 13 years compared to general industry. It is important to note that given the severe economic decline experienced in 2009, several companies, like Gulf Power, did not provide merit increases.

Pay Benchmarking Process

Towers Watson reviewed the benchmarking process at Gulf Power. The review was conducted by analyzing a sample of positions from the following groups:

- Management employees
- Professional employees
- Non-exempt employees
- Employees covered under a collective bargaining agreement (Covered Employees)

In conducting the review, we analyzed over 110 of Gulf Power's positions, which covered 53% of employees.

Outlined below is the Gulf Power benchmarking process that was reviewed to determine if it was consistent with market norms and best practices:

- Select appropriate benchmark positions
- Review and define each position's duties and responsibilities
- Determine relevant labor market for position
- Use compensation surveys reflective of relevant labor market
- Use multiple compensation survey sources, when available
- Match company positions to compensation survey benchmarks reflective of each position's duties and responsibilities
- Develop a "market rate" for each company position matched to compensation survey benchmark jobs
- Assess competitiveness of Gulf Power's positions to the "market rate"

Pay Benchmark Process Findings

Based on our review, the benchmarking process that Gulf Power utilizes is consistent and aligned with utility industry and general industry market best practices.

Competitive Market Positioning

After reviewing Gulf Power's pay benchmarking process, Towers Watson assessed the competitiveness of Gulf Power's current pay levels to the Company's 50th percentile pay philosophy. To conduct this analysis, we utilized published energy services and general industry compensation surveys available to Towers Watson, including our proprietary 2012 Energy Services and General Industry Compensation Databases, reflecting over 125 and 450 survey participants, respectively.

Our analysis finds that for the positions examined, on average, base salaries at Gulf Power fall 6.1% below the market 50th percentile and target total direct compensation (base salary + at-risk pay) falls 6.2% below the market 50th percentile.

Competitive Market Positioning Findings

Based on our assessment, we have determined that Gulf Power's pay is competitive with the market for base salary and target total direct compensation (target TDC = base salary + at-risk pay), as it falls within a reasonable range of the market. The competitive positioning of pay aligns with Gulf Power's stated pay philosophy of targeting the 50th percentile of similarly sized utilities.

At-risk Pay Programs

Towers Watson reviewed Gulf Power's annual at-risk and long-term at-risk pay programs which include:

- Performance Pay Program – the company's annual at-risk program
- Stock Option and Performance Share Programs – the company's long-term at-risk programs

At-risk pay programs (both short-term and long-term) are used by most investor owned utilities and publicly-traded general industry companies to help attract, motivate and retain critically skilled employees needed to successfully run the business. These programs focus employees on both short- and long-term goals. Therefore, Gulf Power's strategy to provide at-risk pay (both short-term and long-term) is consistent with the market perspectives examined.

We assessed the design of both annual at-risk and long-term at-risk pay programs against the Large Utility Peer Group, the Small Utility Peer Group as well as the following proprietary Towers Watson surveys:

- Annual at-risk pay program: Towers Watson's 2010 Annual Incentive Plan Design (AIPD) Survey energy services cut, reflecting 15 energy services industry participants. This survey is typically updated every three years and is expected to be updated at the end of 2013.
- Long-term at-risk pay programs: Towers Watson's 2012 Energy Services Long-term Incentive Plan (LTIP) Report reflecting 114 energy industry participants (survey conducted by Towers Watson for over 20 years)

Below are the findings of Tower Watson's assessment of the competitiveness of both annual at-risk and long-term at-risk pay programs.

Annual At-Risk Pay Program (Performance Pay Program)

Overall, our review indicates Gulf Power's Performance Pay Program is comparable to and competitive with designs of utility peers. Key design aspects are noted below:

- Eligibility – all regular full-time and part-time Gulf Power employees (with some limited exceptions) are eligible to participate in the Performance Pay Program, which aligns with market practice among utility peers

- Performance Measures – the Performance Pay Program assesses performance using a balanced scorecard approach, incorporating both financial (EPS and business unit ROE) and operational (safety, reliability, availability, and customer satisfaction) metrics. The use of a balanced scorecard approach is the most prevalent practice among the utilities examined
  - The use of EPS among all market perspectives examined is very common as 80% of large utility peers, 57% of small utility peers and almost two-thirds of the energy services peers incorporate EPS as part of their annual at-risk pay program
  - Like Gulf Power, the inclusion of business unit metrics in the annual at-risk program is common among large utilities (60% of the Large Utility Peer Group and almost half of Energy Services peers), but Return on Equity (ROE) is not a common metric among utility or energy services peers as only one large and one small utility peer and no energy services industry peer use this metric in their annual at-risk program

- Performance Weightings – all Performance Pay Program participants, from bargaining unit employees to senior management, have similar performance goal weights (33% Corporate EPS, 33% Business Unit Financial Performance and 33% Operational Performance), as the Company wants to emphasize the equal importance of all performance measures
  - Typical market practice applies different goal weights based on organizational level within the company. For example, business unit management employees would typically have greater weight applied to business unit performance than corporate performance to emphasize their stronger "line of sight" (i.e., ability to influence or impact the performance measure)

Long-Term At-Risk Pay Program

Like the annual at-risk pay program, our review of Gulf Power's long-term at-risk pay program indicates the program is comparable to and competitive with utility peer designs. We outline below key design aspects:

- Eligibility – Gulf Power grants long-term at-risk awards deeper into the organization than most utility peers with awards granted to employees in Grade 7 or a base salary midpoint of $106,140. This award level is lower than the median base salary of the lowest eligible recipient at both large and small utility proxy peers and energy services industry peers. Broader long-term at-risk award eligibility at Gulf Power is intended to facilitate a stronger long-term focus for award recipients
- Long-term At-Risk Awards – Gulf Power grants two types of equity awards (stock options and performance shares) when making annual long-term incentive (LTI) grants, which is the majority practice at the three market perspectives examined (60% of the large utility peers, 60% of the small utility peers and over 40% of the energy services industry peers utilize two award types). However, Gulf Power's long-term at-risk program reflects a stronger performance focus than utility peers as all grants are performance-based (stock options require the current stock price to exceed the stock price at the time of grant to have value and performance shares are only earned if relative Total Shareholder Return (TSR) goals are achieved). Most utility peers grant time-based restricted stock and performance shares where time-based restricted stock has no performance focus as the stock is typically awarded after a defined period of employment has lapsed

- Performance Measures – consistent with Gulf Power, most peers (93% of large utility peers, 87% of the small utility peers and over two-thirds of the energy services industry peers) tie some portion of performance share awards to relative total shareholder return (TSR).

- Performance/Payout Range – Gulf Power provides a maximum payout opportunity of 200% of target which is the majority practice among all three market perspectives examined. However, Gulf Power requires stronger relative TSR performance (90th percentile achievement against peers) than large utility peers which typically only require 75th percentile TSR performance for a maximum award to be earned. Small utility peers are almost evenly split between requiring the same/higher relative TSR performance level (90th, 95th or 100th percentile) or a performance level below Gulf Power's level (75th, 80th or 85th percentile) to receive a maximum award opportunity. Gulf Power's maximum relative TSR performance achievement level is consistent with the energy services industry peers market perspective

- Peer Groups – performance share awards at Gulf Power are measured against two peer groups to determine if awards are earned. Most utility peers use a single peer group as opposed to two. Gulf Power uses two peer groups to measure performance against a broad utility market perspective reflecting an independent third party index (Philadelphia Utility Index) and a custom peer group of utilities with similar business model and size

At-risk Pay Programs Findings

Our competitive market review indicates Gulf Power's at-risk pay programs are comparable to and competitive with plan designs of other similarly sized utilities.

Conclusion

In summary, we find the form, mix and levels of total pay at Gulf Power to align with the Company's stated pay philosophy and the market practices of utility peers. The market competitive pay program enables Gulf Power to attract, retain and motivate employees needed for continued success.

* * * *

We hope this information is helpful and would be happy to discuss this information in more detail at your convenience.

cc: Mike Butts – Southern Company Services

TOWERS WATSON

Exhibit 1

Large Utility Peer Group

Company	Ticker	Revenue ($000s)	Number of Employees
AES Corp.	AES	$18,141	25,000
American Electric Power Company	AEP	$14,945	18,513
Consolidated Edison	ED	$12,188	14,529
Dominion Resources	D	$13,093	15,500
DTE Energy	DTE	$8,791	9,900
Duke Energy	DUK	$19,158	18,249
Edison International	EIX	$11,862	16,593
Entergy	ETR	$10,302	14,625
Exelon	EXC	$23,489	26,057
FirstEnergy	FE	$14,848	16,495
NextEra Energy	NEE	$14,256	14,400
PG&E	PCG	$15,040	20,593
PPL Corp.	PPL	$12,286	17,729
Public Service Enterprise Group	PEG	$9,781	9,798
Xcel Energy	XEL	$10,128	11,113

25th Percentile	$10,259	14,497
Median	$12,690	16,544
75th Percentile	$14,969	18,315

Data source: Standard & Poor's Capital IQ. Company revenue and employee data reflect fiscal 2012 data.

TOWERS WATSON

Exhibit 1

Small Utility Peer Group

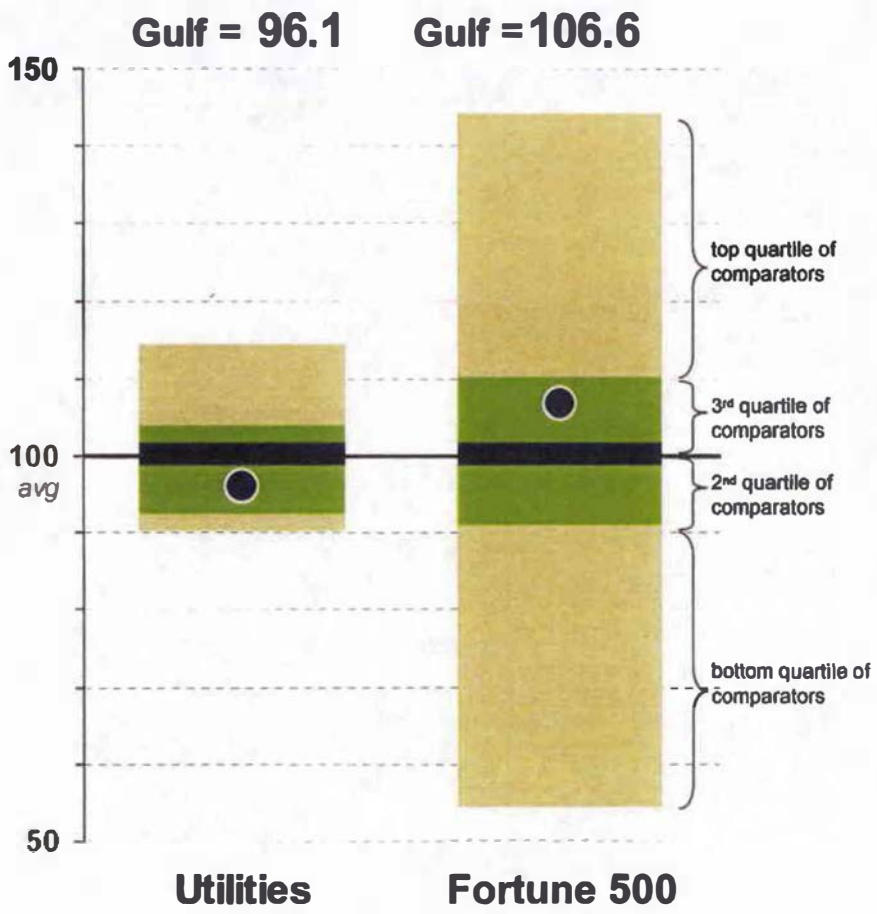
Company	Ticker	Revenue ($000s)	Number of Employees
ALLETE, Inc.	ALE	$961	1,342
Avista Corp.	AVA	$1,547	3,124
Black Hills Corporation	BKH	$1,174	1,925
CH Energy Group Inc.	CHG	$925	1,235
Cleco Corporation	CNL	$994	1,259
El Paso Electric Co.	EE	$853	1,000
Great Plains Energy Incorporated	GXP	$2,310	3,090
IdaCorp, Inc.	IDA	$1,081	2,090
Northwestern Corp.	NWE	$1,070	1,430
Otter Tail Corporation	OTTR	$859	2,286
PNM Resources, Inc.	PNM	$1,342	1,909
Portland General Electric Company	POR	$1,805	2,603
UIL Holdings Corporation	UIL	$1,487	1,865
UNS Energy Corporation	UNS	$1,462	1,979
Westar Energy, Inc.	WR	$2,261	2,313

25th Percentile	$1,013	1,539
Median	$1,258	1,952
75th Percentile	$1,532	2,306

Data source: Standard & Poor's Capital IQ. Company revenue and employee data reflect fiscal 2012 data.

Employer-Paid Value of Gulf's Benefits vs. Comparator Groups

Benefit Index® Results



Value of Gulf's benefits are:

- 96.1% of the average value of benefits provided by a group of 14 large utilities
- 106.6% of the average value of benefits provided by 251 of the Fortune 500 companies
- Values of benefits determined using Aon Hewitt's Benefit Index® methodology

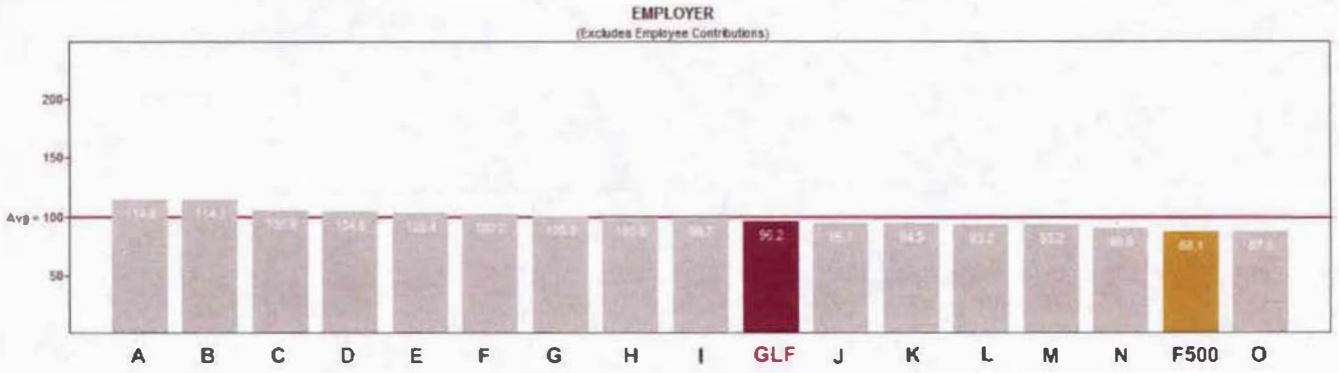
Reading results chart

- Charts show the relative value of benefits provided by Gulf and each comparator group
- 100 = average value of benefits for the comparator group
- Columns show range of comparators' benefit values
- Blue dots indicates relative value of Gulf's benefits

AON Hewitt

Florida Public Service Commission
Docket No. 130140-EI
GULF POWER COMPANY
Witness: James M. Garvie
Exhibit No.____(JMG-1)
Schedule 4
Page 1 of 1

Entire Benefit Program



- For the entire benefit program, Gulf Power is 3.8% below average for employer provided benefits

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Schedule 5
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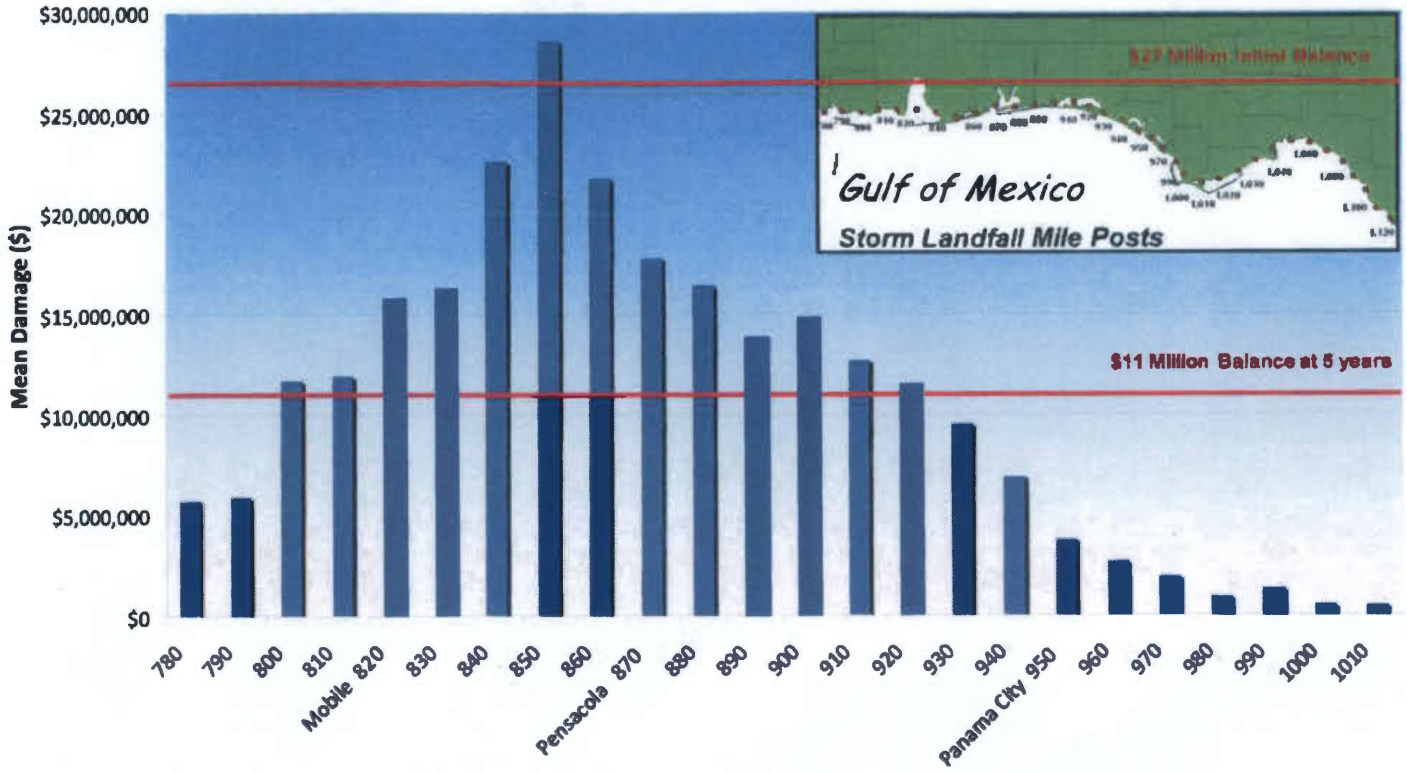

Schedule 1: Protection afforded by an initial balance of $27,000,000 and annual accrual of $3,500,000 against potential average transmission & distribution damage from single SSI1 landfalls at mile posts.

Florida Public Service Commission
Docket No. 130140-EI
GULF POWER COMPANY
Witness: Steven P. Harris
Exhibit No. _____ (SPH-1)
Schedule 1
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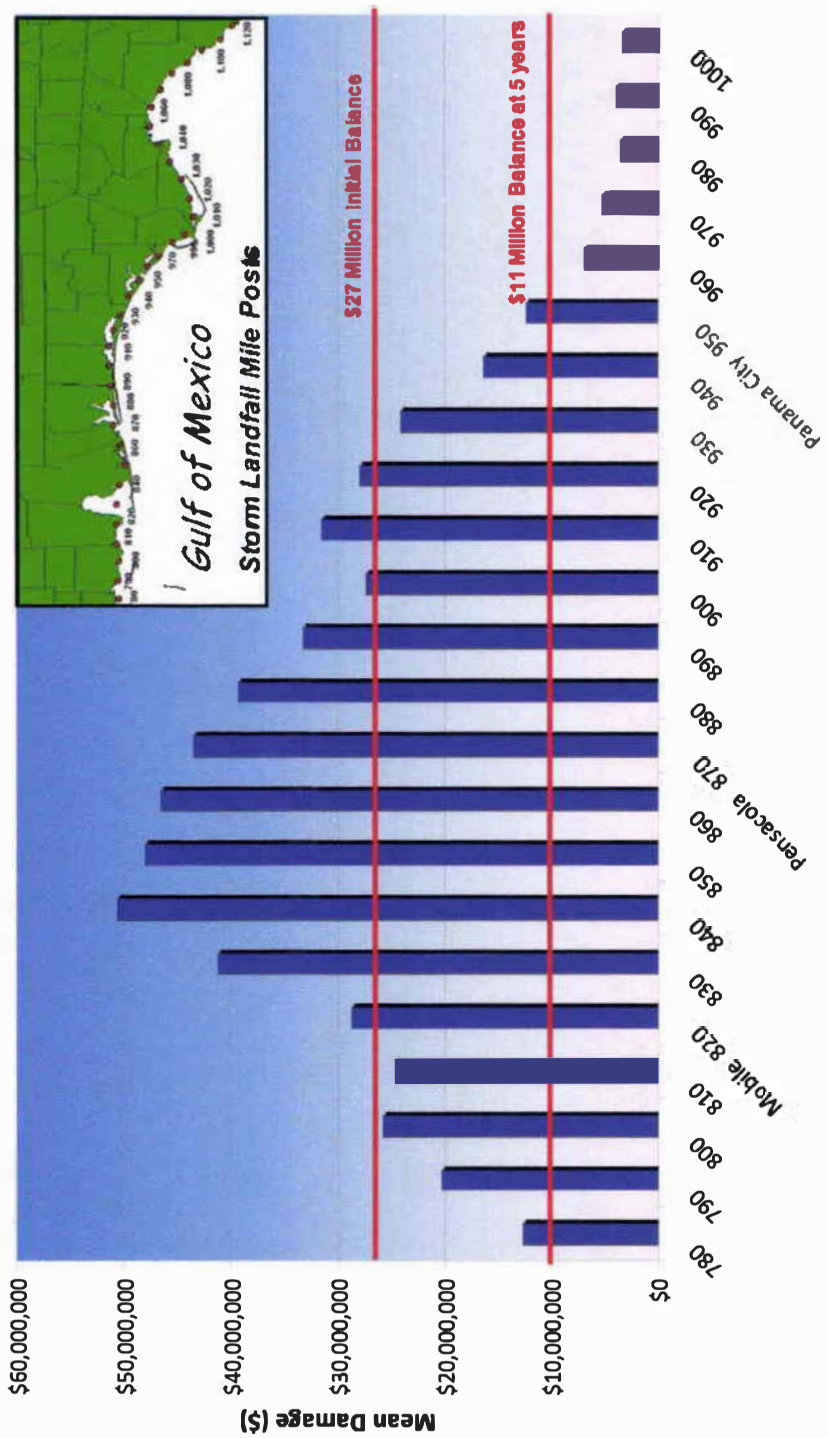
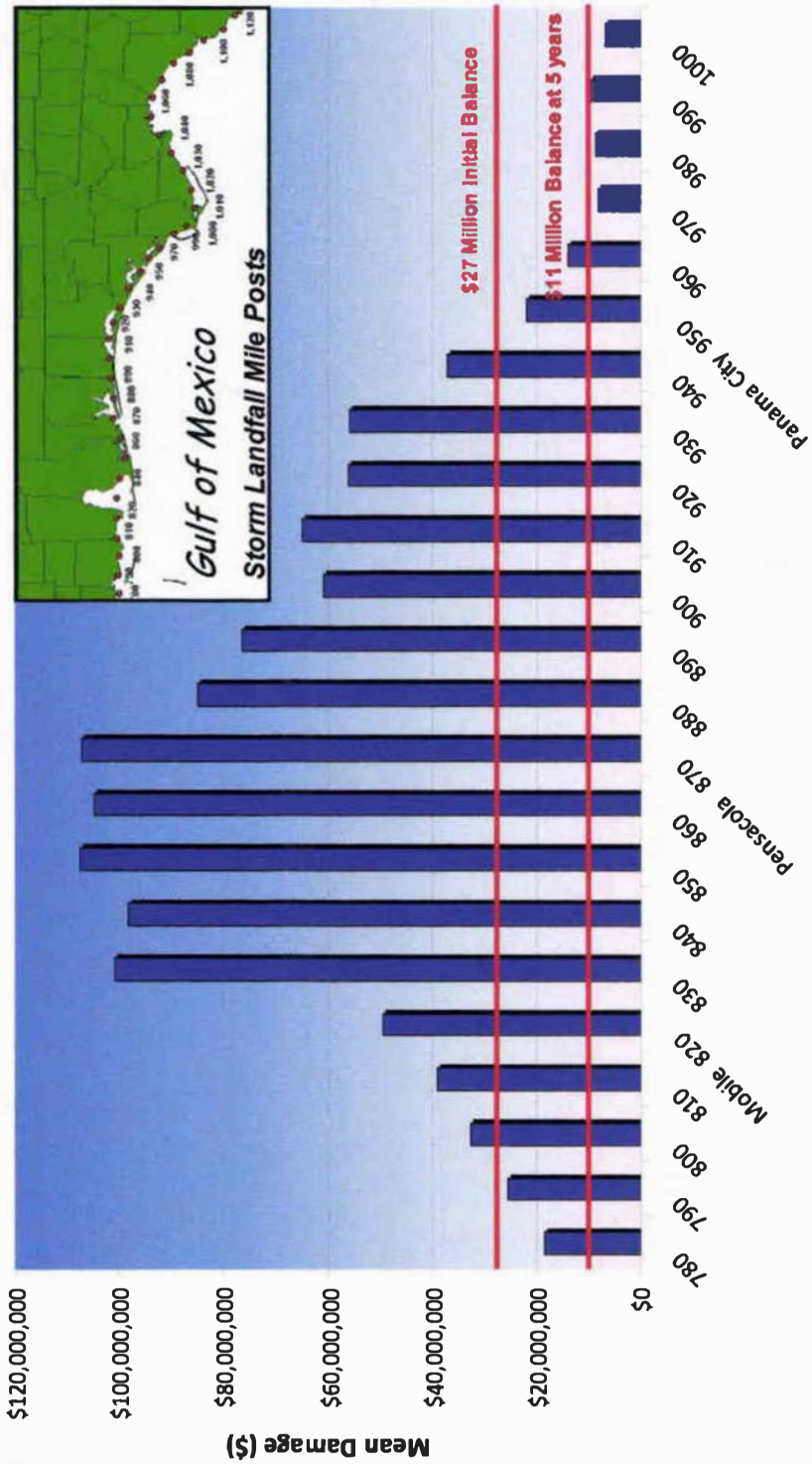
FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130140-EI EXHIBIT 17
PARTY Gulf Power Company (Gulf) Direct
DESCRIPTION Steven P. Harris (SPH-1)
DATE

Florida Public Service Commission
Docket No. 130140-EI
GULF POWER COMPANY
Witness: Steven P. Harris
Exhibit No. _____ (SPH-1)
Schedule 2
Page 1 of 1



Schedule 2: Protection afforded by an initial balance of $27,000,000 and annual accrual of $3,500,000 against potential average transmission & distribution damage from single SSI2 landfalls at mile posts.



Schedule 3: Protection afforded by an initial balance of $27,000,000 and annual accrual of $3,500,000 against potential average transmission & distribution damage from single SSI3 landfalls at mile posts.

Florida Public Service Commission
Docket No. 130140-EI
GULF POWER COMPANY
Witness: Steven P. Harris
Exhibit No. _____ (SPH-1)
Schedule 4
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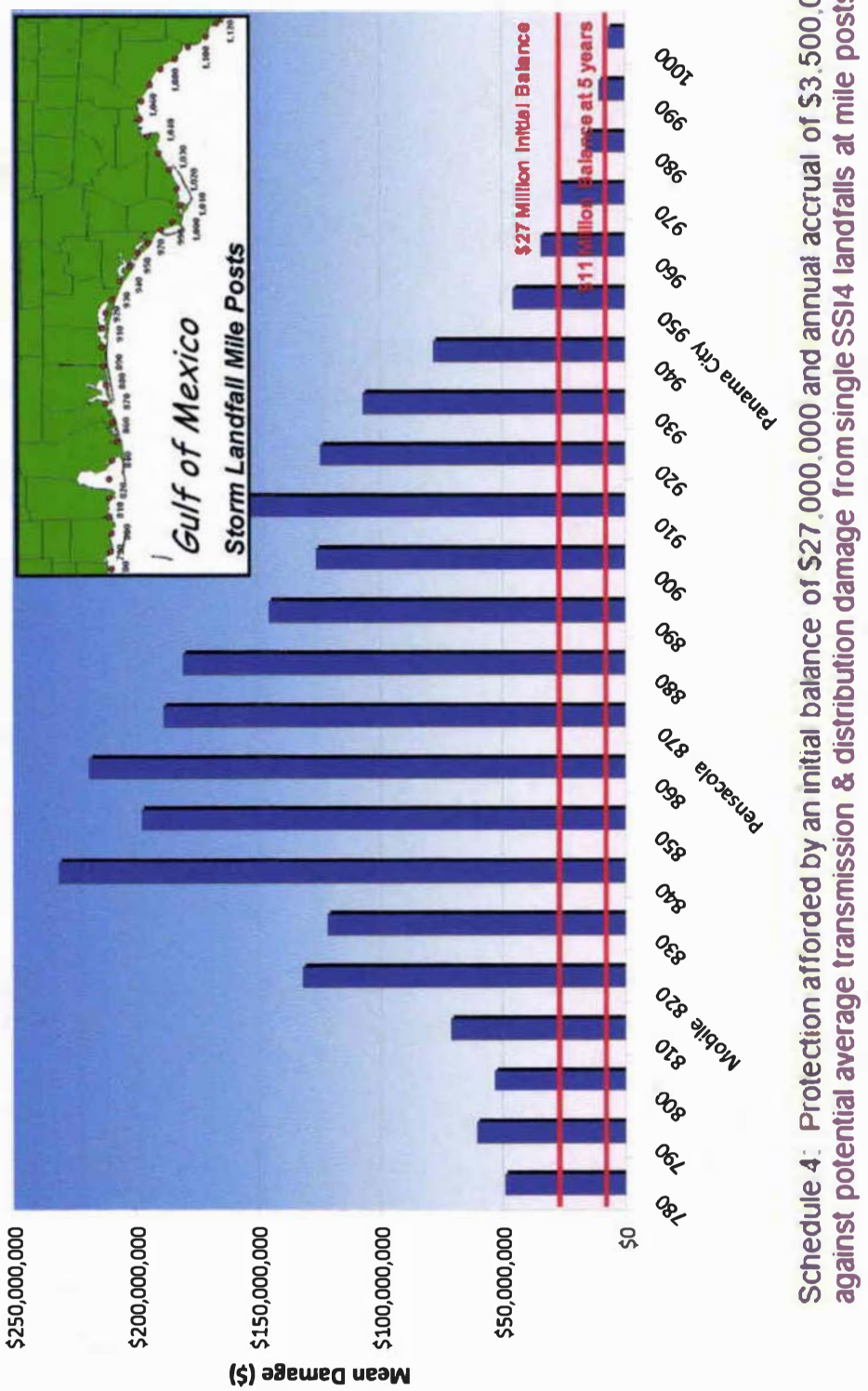

Schedule 4: Protection afforded by an initial balance of $27,000,000 and annual accrual of $3,500,000 against potential average transmission & distribution damage from single SSI4 landfalls at mile posts.

See Attached:

Gulf Power Company
Transmission and Distribution Hurricane Loss and Reserve Performance Analyses

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DOCKET NO. 130140-EI EXHIBIT 18
PARTY Gulf Power Company (Gulf) Direct
DESCRIPTION Steve P. Harris (SPH-2)
DATE

EQECAT
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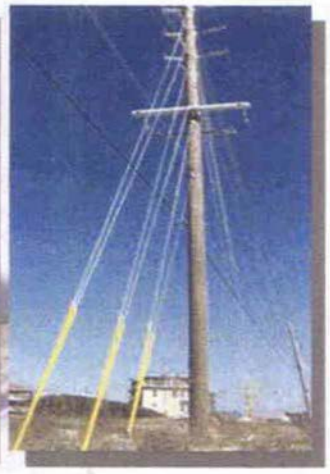
Gulf Power Company

Transmission and Distribution Hurricane Loss and Reserve Performance Analyses



January 2011

GULF POWER
A SOUTHERN COMPANY

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Executive Summary

Gulf Power (Gulf) transmission and distribution (T & D) systems are exposed to and in the past have sustained damage from hurricanes. The exposure of these assets to hurricane damage is described and potential losses are quantified. Loss analyses were performed by EQECAT, using an advanced computer model simulation program WORLDCATenterprise USWIND™.

The hurricane exposure is analyzed from a probabilistic approach, which considers the full range of potential hurricane characteristics and corresponding losses. Factors considered in the analysis include the location of Gulf's T & D assets, the probability of hurricanes of different intensities and landfall points impacting those assets, the vulnerability of those assets to hurricane damage, and the costs to repair assets and restore electrical service.

The frequencies and computed damage for all simulated hurricanes are combined to calculate the expected annual loss and the annual aggregate exceedance relations. The expected annual damage represents the average of all storm years over a long period of time. There is a 10% probability that damage to T&D assets from all hurricanes in one year could exceed $22 million, and a 1% probability that damage could exceed $140 million.

An analysis was also performed to simulate the performance of Gulf's reserve fund over a five year prospective period. This probabilistic analysis is based on the losses and frequencies of occurrence of hurricanes, and the current level of annual accruals to the reserve. This anaysis shows the reserve fund balance is expected to decline from the current $27 million to $11 million at the end of five years. There is a 29% probability that the reserve could have inadequate funds to cover hurricane damage over the five year simulation period.

A summary of the analyses performed by EQECAT of Gulf's hurricane loss exposure and reserve performance are provided in the risk profile in Table E-1 below.

This report is intended to be used solely by Gulf and the Florida Public Service Commission for estimation of potential future Gulf losses to the reserve and the estimation of the performance of the reserve fund.

Table E-1

Gulf Power Company Transmission and Distribution Risk Profile

OWNER	**Gulf Power Company**	
ASSETS	Transmission and Distribution (T & D) System consisting of: Transmission towers, and conductors; Distribution poles, transformers, conductors, lighting and other miscellaneous assets	
LOCATION	All T & D assets located within State of Florida	
ASSET VALUE	Normal replacement value is approximately $ 2.2 billion, of which approximately 21% is transmission and 79% is distribution	
LOSS PERIL	Hurricane Windstorm (SSI 1 to 5)	
EXPECTED ANNUAL DAMAGE	$8.3 million	
10% AGGREGATE DAMAGE EXCEEDANCE VALUE	$22 million (one year)	
1% AGGREGATE DAMAGE EXCEEDANCE VALUE	$140 million (one year)	
	RESERVE PERFORMANCE	
Reserve Fund Initial Balance	**Expected Fund Balance at 5 years**	**Probability of negative balances within 5 years**
$27 million	$11 million	29%

1. Hurricane Loss Analysis

Gulf Power (Gulf) transmission and distribution (T & D) systems are exposed to and in the past have sustained damage from hurricanes. The exposure of these assets to hurricane damage is described and potential losses are quantified. Loss analyses were performed by EQECAT, using an advanced computer model simulation program WORLDCATenterprise USWIND ™ developed by EQECAT, an ABS Group Company. All results which are presented here have been calculated using USWIND, and Gulf provided T & D asset portfolio data.

The hurricane exposure is analyzed from a probabilistic approach, which considers the full range of potential hurricane characteristics and corresponding losses. Probabilistic analyses identify the probability of damage exceeding a specific dollar amount. WORLDCATenterprise USWIND™ is a probabilistic model designed to estimate damage and losses due to the occurrence of hurricanes. EQECAT proprietary computer software USWIND is one of only four models evaluated and determined acceptable by the Florida Commission on Hurricane Loss Projection Methodology (FCHLPM) for projecting hurricane loss costs and approved for use in insurance rating (Reference 1).

Probabilistic Annual Damage & Loss is computed using the results of thousands of random variable hurricanes. Annual damage and loss estimates are developed for each individual site and aggregated to overall portfolio damage and loss amounts. Damage is defined as the Operations and Maintenance (O&M) portion of the cost, exclusive of capital and nominal labor, associated with repair and/or replacement of T & D assets necessary to promptly restore service in a post hurricane environment. This cost is typically larger than the costs associated with scheduled repair and replacement programs.

Factors considered in the analysis include locations of Gulf's overhead T & D assets, the probability of hurricanes of different intensities and/or landfall points impacting those assets, the vulnerability of those assets to hurricane damage, and the costs to repair assets and restore electrical service.

Transmission and Distribution asset data are provided in the Tables 1-1 and 1-2 below. Distribution asset values are shown in Figure 1-1.

Table 1-1

Overhead Distribution Asset Replacement Values by County

County	Replacement Value ($1,000)
Escambia	410,976
Bay	221,048
Okaloosa	206,440
Santa Rosa	188,933
Washington	45,271
Walton	39,078
Holmes	14,624
Jackson	9,136
Total	**1,135,506**

Table 1-2

Overhead Transmission Asset Replacement Value

	Replacement Value ($1,000)
Total	**463,579**

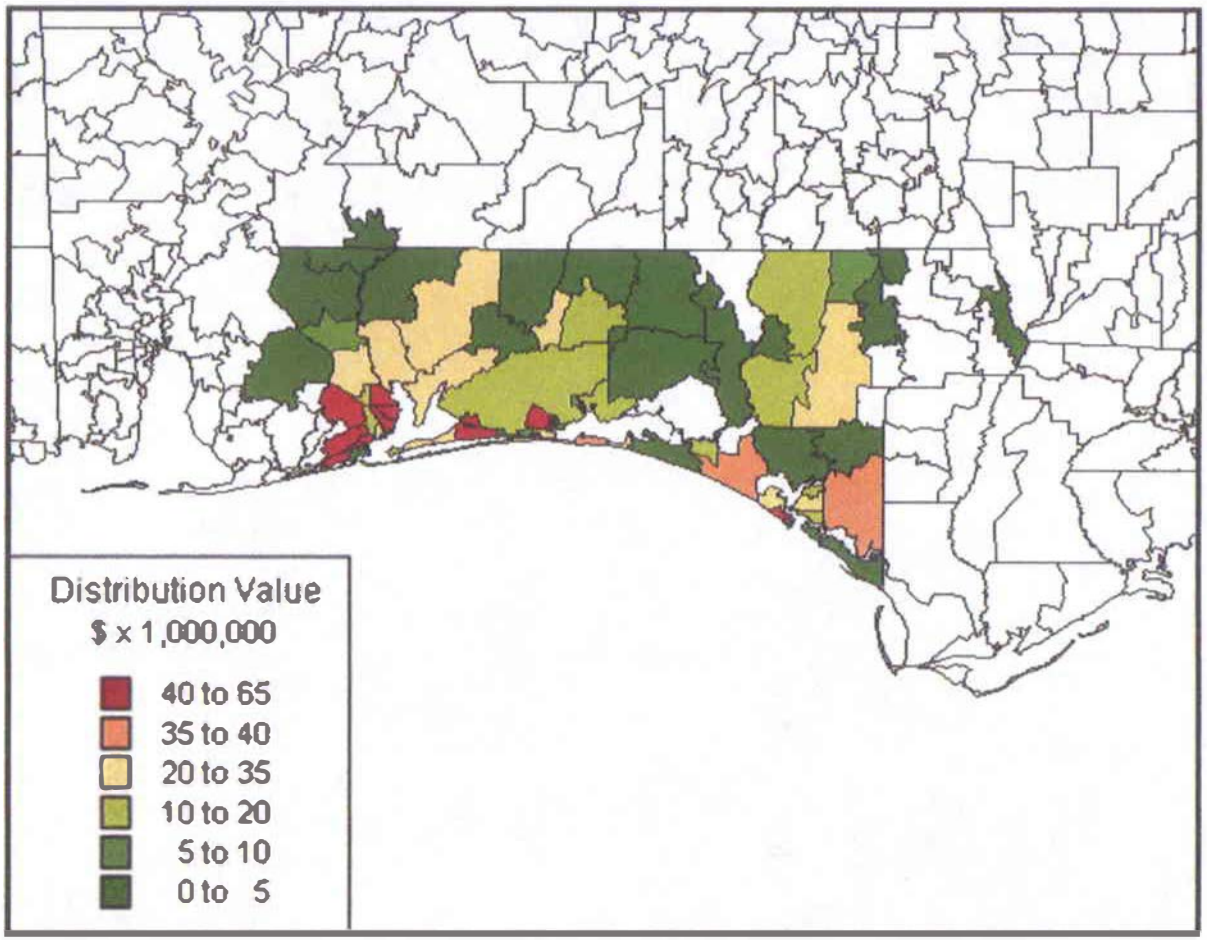

Figure 1-1: Overhead Distribution Asset Values by Zip Code

Transmission and Distribution Asset Vulnerabilities

The Gulf Power loss history from the 2004 Hurricane Ivan, 2005 Hurricane Dennis and Katrina were considered in the calibration of the hurricane loss model. These hurricanes provide data on recent hurricane recovery costs from moderate intensity events. The 2004-05 hurricane loss experience includes the effects of many factors including the post hurricane costs of labor, mutual aid and other factors associated with the hurricane restoration process utilized by Gulf Power. The 2004-05 loss history is believed to be most reflective of the current Gulf hurricane restoration practices and cost experience.

Loss Estimation Methodology

The basic components of the hurricane risk analysis include:

- **Assets at risk:** define and locate
- **Hurricane hazard**: apply probabilistic hurricane model for the region
- **Asset vulnerabilities:** severity (wind speed) versus damage
- **Portfolio Analysis:** probabilistic analysis -damage/ loss

2. Hurricane Hazard

Hurricane Exposure

The hurricane exposure is analyzed from a probabilistic approach, which considers the full range of potential hurricane characteristics and corresponding losses. Probabilistic analyses identify the probability of damage exceeding a specific dollar amount. WORLDCATenterprise USWIND™ is a probabilistic model designed to estimate damage and losses due to the occurrence of hurricanes. EQECAT, Inc. proprietary computer software USWIND is one of only four models evaluated and determined acceptable by the Florida Commission on Hurricane Loss Projection Methodology (FCHLPM) for projecting hurricane loss costs and approved for use in insurance rating.

The historical annual frequency of hurricanes has varied significantly over time. There are many causes for the temporal variability in hurricane formation. While stochastic variability is a significant factor, many scientists believe that the formation of hurricanes is also related to climate variability.

One of the primary climate cycles having a significant correlation with Hurricane activity is the Atlantic Multidecadal Oscillation (AMO). It has been suggested that the formation of hurricanes in the Atlantic Ocean off the coast of Africa is related to the amount of rainfall in the Western African Sahel region. Years in which rainfall is heavy have been associated with the formation of a greater number of hurricanes. The AMO cycle consists of a warm phase, during which the tropical and sub-tropical North Atlantic basins have warmer than average temperatures at the surface and in the upper portion relevant to hurricane activity, and a cool phase, during which these regions of the ocean have cooler than average temperatures. In the period 1900 through 2005, the AMO has gone through the following phases:

1900 through 1925	Cool	(Decreased Hurricane Activity)
1926 through 1969	Warm	(Increased Hurricane Activity)
1970 through 1994	Cool	(Decreased Hurricane Activity)
1995 through 2010	Warm	(Increased Hurricane Activity)

These AMO phases are illustrated by the plot of Sea Surface Temperature (SST) Anomalies (deviation from the mean) in the Atlantic Basin over the past 150 years in Figure 2-1.

The National Oceanic and Atmospheric Administration (NOAA) believes that we entered a warm phase of AMO around 1995 which can be expected to continue for at least several years; historically, each phase of AMO has lasted approximately 25 to 40 years.

Probabilistic Annual Damage & Loss is computed using the results of thousands of random variable hurricanes considering the long term 100 year hurricane hazard. Annual damage estimates are developed for each individual site and aggregated to overall portfolio damage amounts. Damage is defined as the total cost including the operations and maintenance (O&M) and capital components associated with repair and/or replacement of T & D assets necessary to promptly restore service in a post hurricane environment. This cost is typically larger than the costs associated with scheduled repair and replacement programs.

Primary factors considered in the analysis include the location of Gulf Power Company's overhead T & D assets, the probability of hurricanes of different intensities and/or landfall points impacting those assets, the vulnerability of those assets to hurricane damage, and the costs to repair assets and restore electrical service.

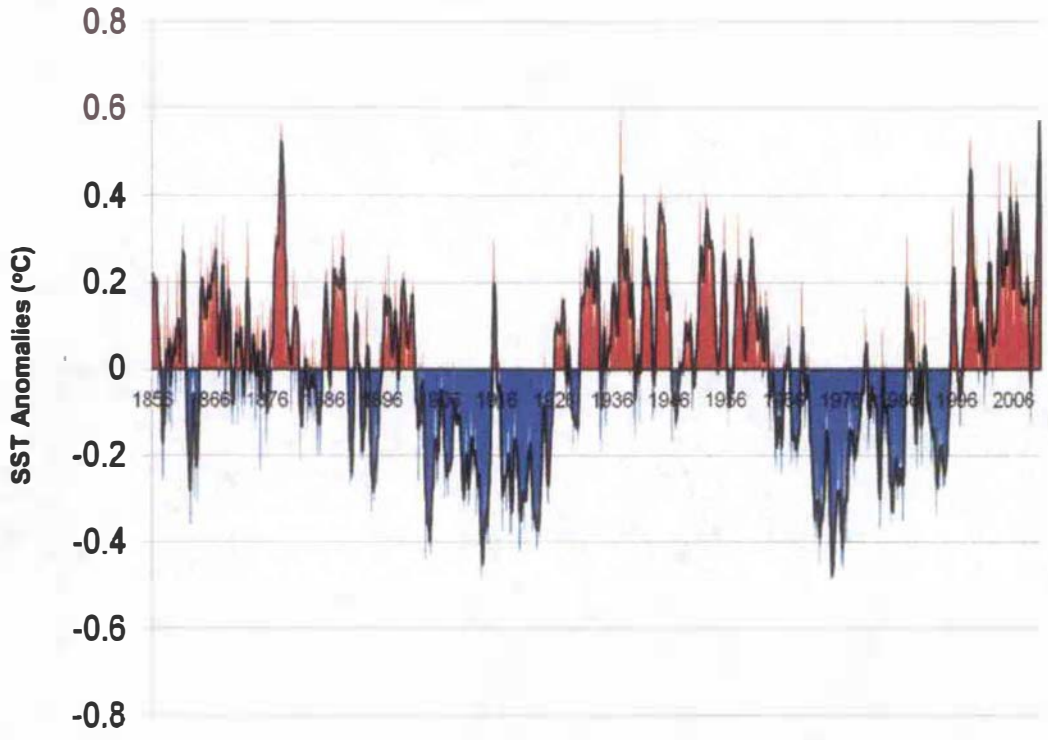

Figure 2-1: Atlantic Multidecadal Oscillation in Sea Surface Temperatures 1856-2010

3. Hurricane Landfall Analyses for SSI Ranges

In order to provide further insight into Gulf's risk profile, the full set of stochastic hurricane events were analyzed by landfall for four storm intensities, SSI 1 through 4. The landfall locations are at mile posts 780 through 1010. Figure 3-1 illustrates the landfall locations. These mile posts extend east from Pascagoula, MS to Apalachicola, FL at approximately 10 mile intervals.

The full set of stochastic storms within each SSI category was analyzed on Gulf's T&D portfolio. For each milepost and SSI category, the frequency-weighted average damage was computed from all stochastic storms making landfall within 10 nautical miles of a given milepost and within that SSI category. Figures 3-2 through 3-5 provide these results graphically.

Figure 3-1: Storm Landfall Mile Posts

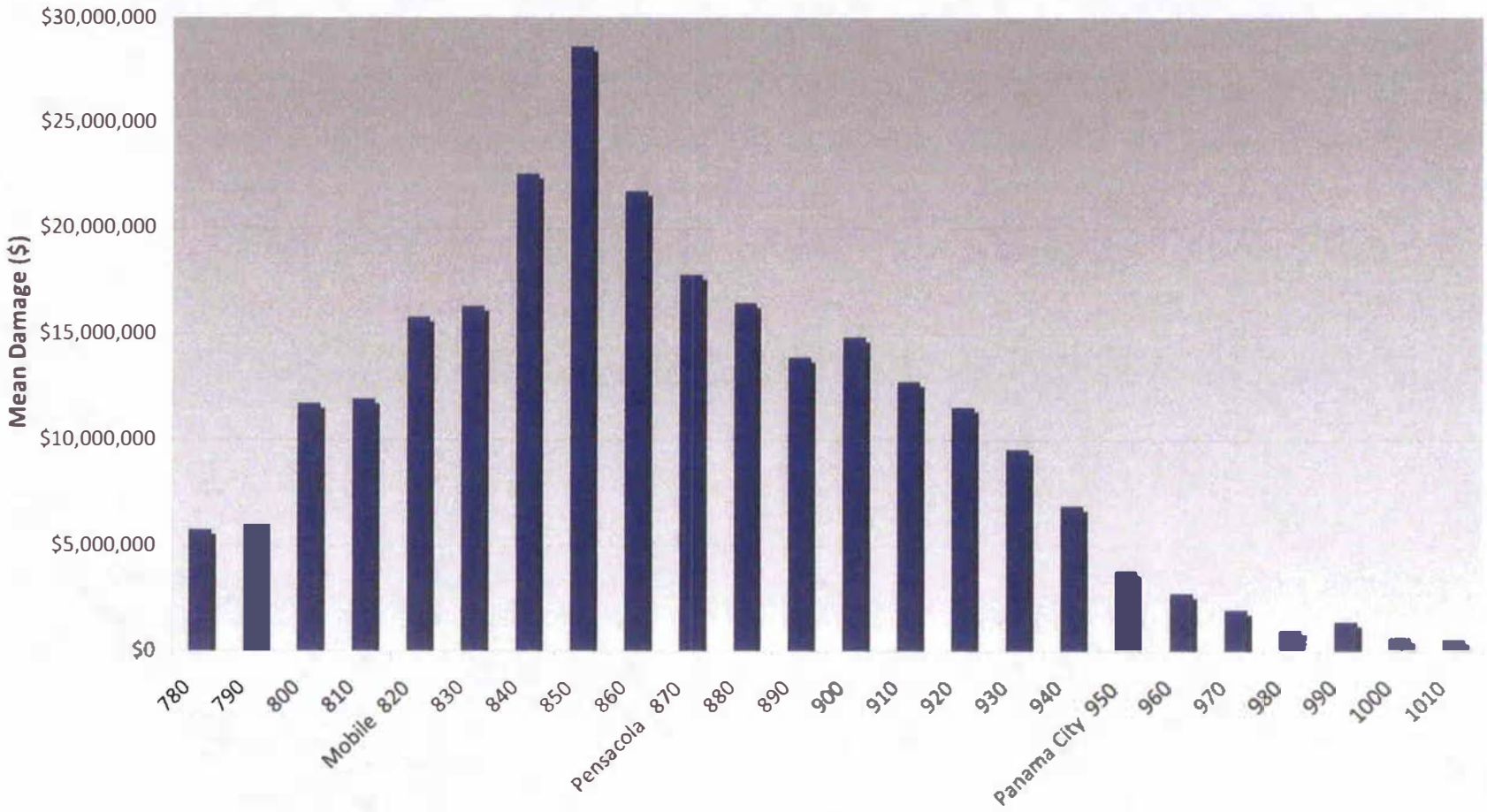

Figure 3-2: Frequency Weighted Average Transmission & Distribution Damage from SSI 1 Landfalls

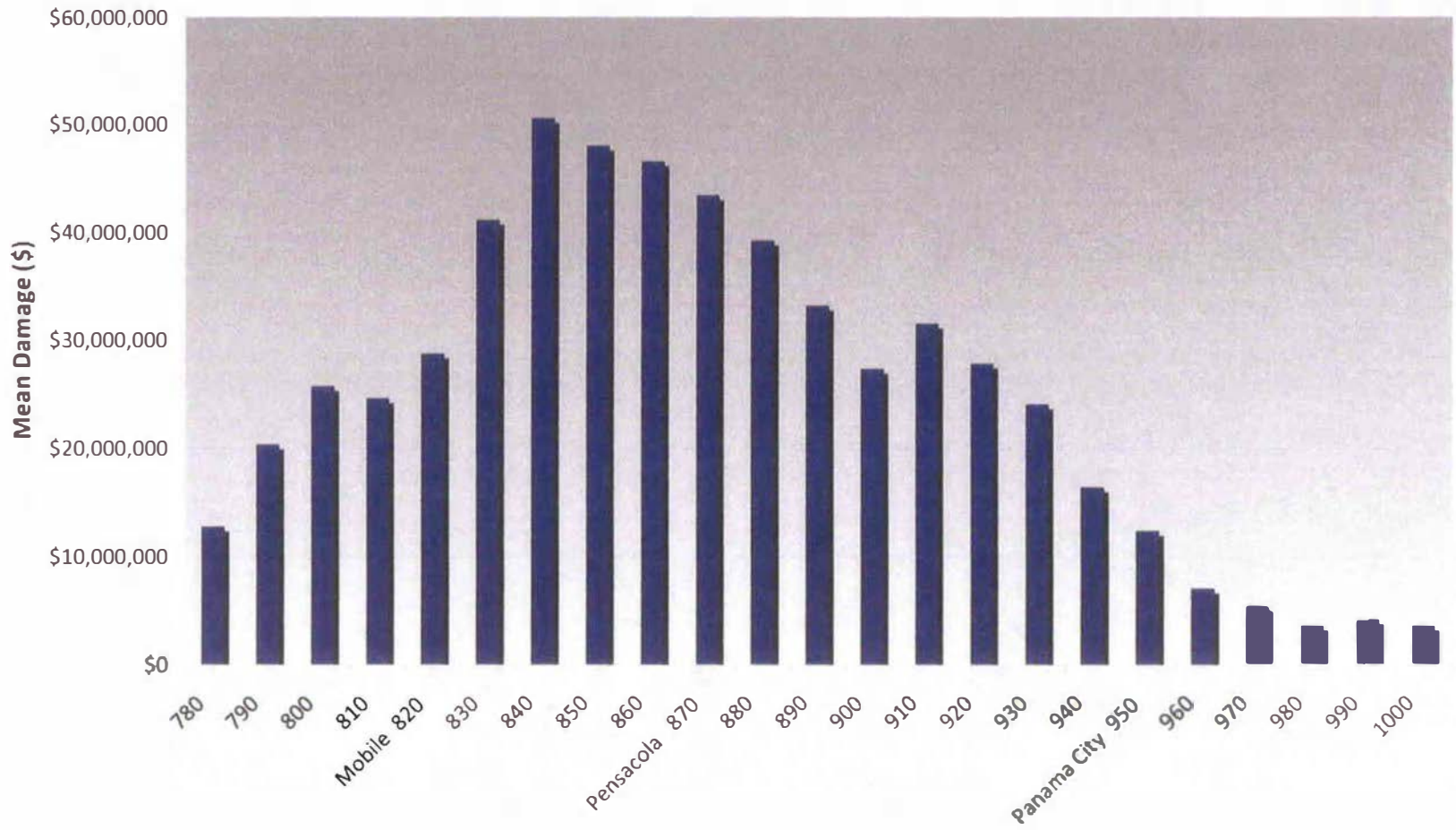

Figure 3-3: Frequency Weighted Average Transmission & Distribution Damage from SSI 2 Landfalls

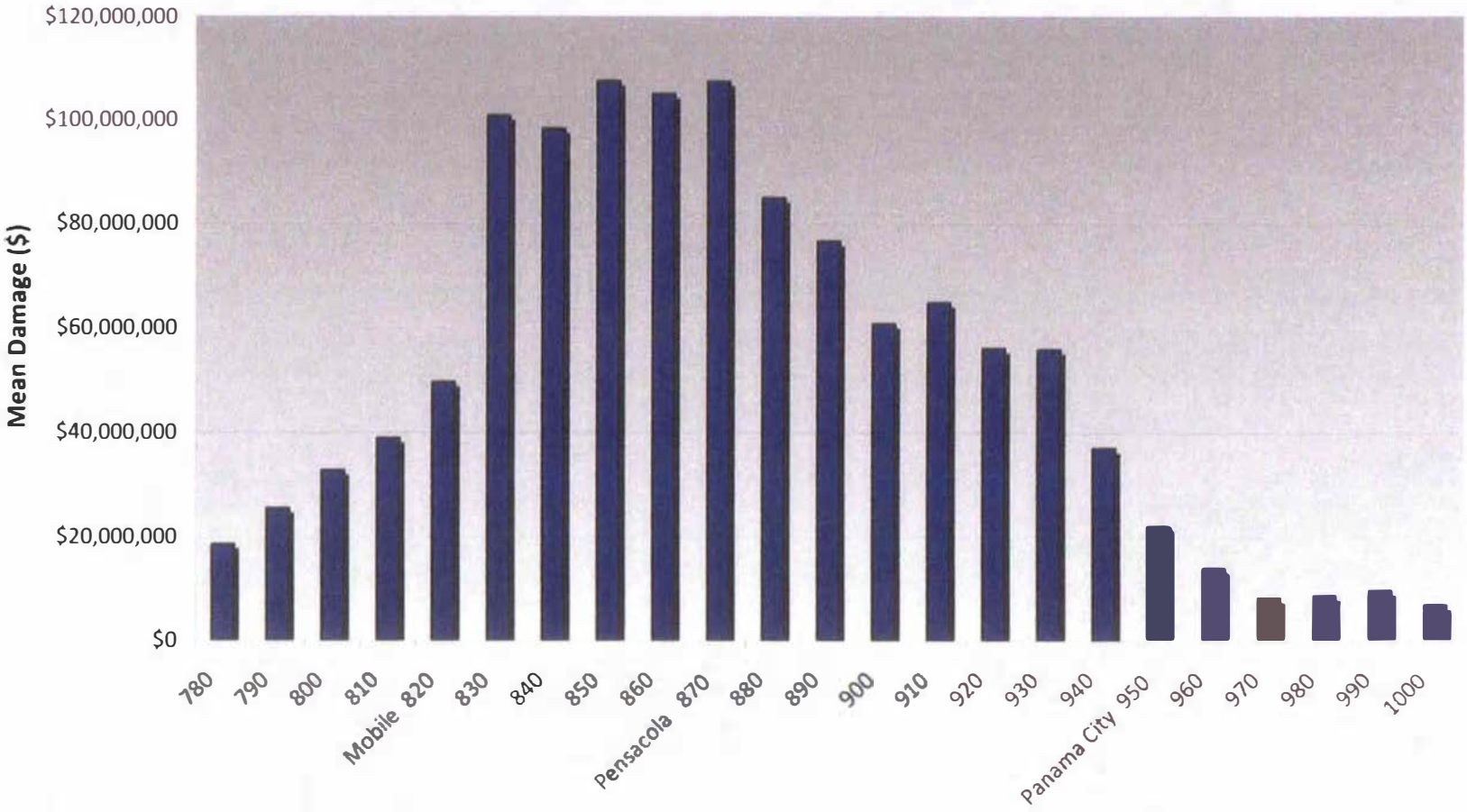

Figure 3-4: Frequency Weighted Average Transmission & Distribution Damage from SSI 3 Landfalls

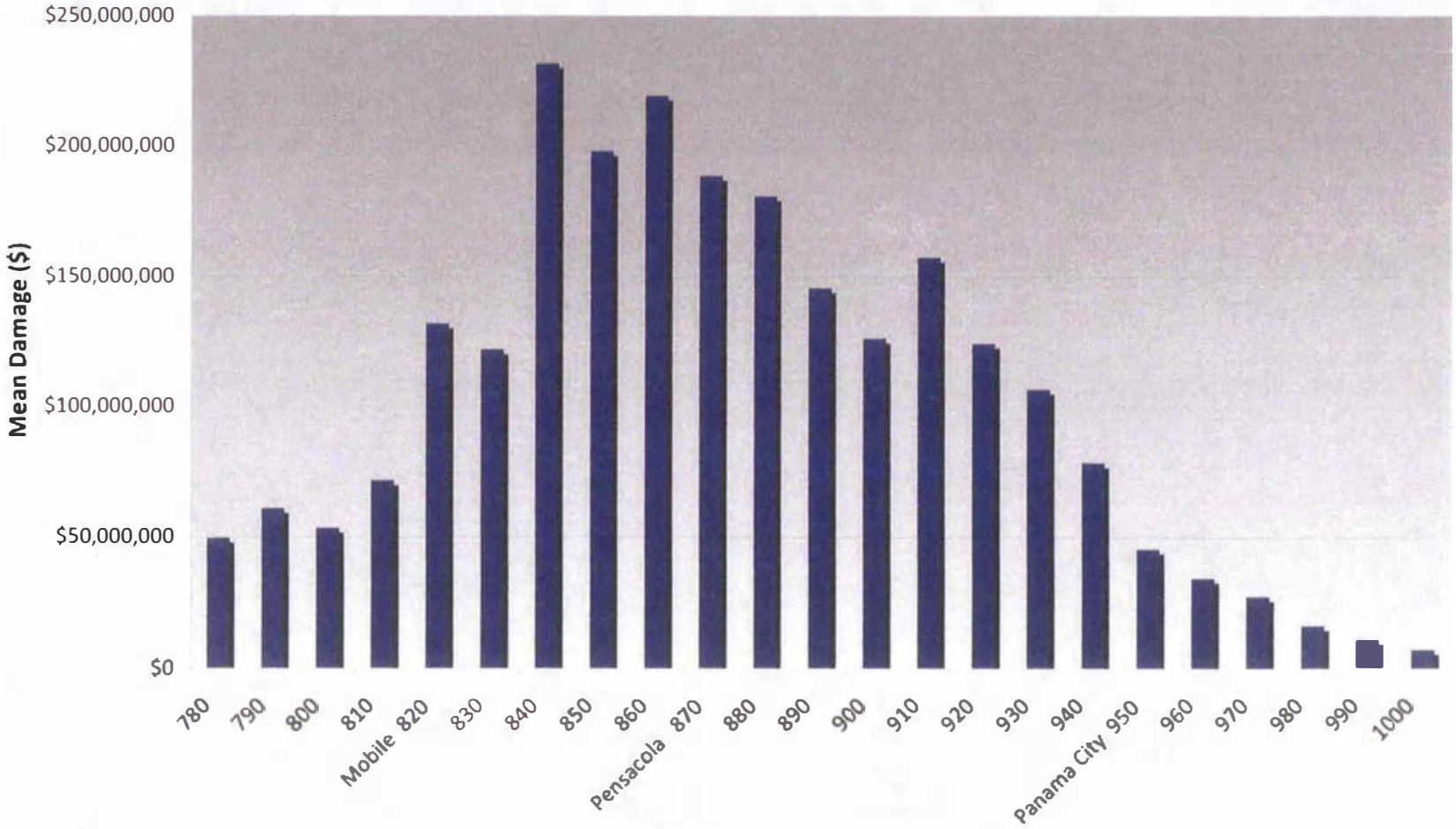

Figure 3-5: Frequency Weighted Average Transmission & Distribution Damage from SSI 4 Landfalls

4. Hurricane Loss Analysis Results

Aggregate Damage Exceedance and Expected Annual Damage

A probabilistic database of losses is developed using the hurricane hazard, assets at risk and their vulnerabilities. For each hurricane, the center, shape, geographical orientation, track and wind speeds were defined. The wind field for each hurricane is integrated with the asset vulnerability and the asset locations to compute the damage. The annual frequency and the portfolio damage for each simulated hurricane is determined. By querying this database of thousands of hurricane losses, various loss exceedance or non-exceedance distributions are generated. The frequencies and computed damage for all hurricanes are combined to calculate the expected annual loss and the annual aggregate exceedance relations.

Aggregate damage exceedance calculations are developed by keeping a running total of damage from ***all possible events*** in a given time period. At the end of each time period, the aggregate damage for all events is then determined by probabilistically summing the damage distribution from each event, taking into account the event frequency. The process considers the probability of having zero events, one event, two events, etc. during the time period. Each event within the EQECAT stochastic event set is unique, described by a frequency of occurrence, severity, azimuth of landfall, central track, radius to maximum winds, hurricane profile and other critical parameters.

A series of probabilistic analyses were performed, using the vulnerability curves derived for Gulf assets and the computer program USWIND™. A summary of the analysis is presented in Table 5-1, which shows the aggregate damage (i.e. deductible is "0") exceedance probability for damage layers between zero and over $250 million dollars.

For each damage layer shown, the probability of damage exceeding a specified value is shown. For example, the probability of damage exceeding $100 million in one year is 1.9%. The analysis calculates the probability of damage from all hurricanes and aggregates the total.

Table 4-1 provides the aggregate damage exceedance probabilities for the Gulf T & D assets analyzed for a series of layers. Each layer has a layer amount of $10 million, except for the final layer which represents all damage $250 million and greater. The value in the first column, labeled Damage Layer, is the attachment point for each layer, with the exception of the last layer, for which the attachment point is $250 million.

The second column of the table, labeled 1 year Exceedance Probability, provides the 1-year modeled probability of penetrating each layer, i.e. the probability that the total damage from all events in a 1 year period will exceed the attachment point of the layer.

The expected annual damage (EAD) and exposure to Gulf's Reserve from hurricanes is $8.3 million. This value represents the average damage from all simulated hurricanes over a long time horizon within the EQECAT stochastic event set. The EAD is not expected to occur each and every year. Some years will have no damage from hurricanes, some years will have small amounts of damage and a few years will have large amounts of damage.

Table 4-1

GULF POWER COMPANY T & D ASSETS
AGGREGATE DAMAGE EXCEEDANCE PROBABILITIES

Damage Layer ($millions)	1 Year Exceedance Probability
0 (>0.5)	24.5%
10	15.4%
20	10.8%
30	8.03%
40	6.23%
50	4.96%
60	4.02%
70	3.30%
80	2.74%
90	2.29%
100	1.93%
110	1.63%
120	1.39%
130	1.18%
140	1.01%
150	0.87%
160	0.75%
170	0.65%
180	0.57%
190	0.49%
200	0.43%
210	0.38%
220	0.34%
230	0.30%
240	0.26%
>250	0.23%

5. Reserve Performance Analysis

A probabilistic analysis of losses from hurricanes was performed for Gulf Power (Gulf) to determine their potential impact on the Reserve fund.

Analysis

The Reserve performance analysis consisted of performing 10,000 iterations of hurricane loss simulations within the Gulf service territory, each covering an 8-year period, to determine the effect of the charges for damage on the Gulf Reserve. Monte Carlo simulations were used to generate damage samples for the analysis. The analysis provides an estimate of the Reserve assets in each year of the simulation, accounting for the annual accrual, expenses, fund earnings when balances are positive, borrowing costs when fund balances are negative and hurricane damage using a dynamic financial model.

Assumptions

The analysis performed included the following assumptions:

- An initial Reserve balance of $27 million.
- Annual Reserve accruals of $3.5 million were assumed in the analysis.
- Hurricane losses are assumed to increase by 4% per year as replacement values of T&D increase due to inflation and system growth.
- Negative Reserve balances are assumed to be financed with an unlimited line of credit costing 3.8%.
- Positive Reserve balances are assumed to earn at an annual rate of 3. 6%.
- $6.8 million of the $8.3 million Expected Annual Loss, determined in the Loss Analysis, is assumed to be an obligation of the reserve annually.
- All results are shown in constant 2009 Reserve dollars.

The analysis results for the case analyzed are shown in Table 5-1 below. The results show the Annual Reserve Accrual amount, the mean (expected) Reserve fund balance as well as the probability that the Reserve fund balance will be negative in any one or more of the five years of the simulated time horizon.

Table 5-1
GULF POWER COMPANY T & D
RESERVE FUND ACCRUALS AND
PROBABILITY OF RESERVE FUND PERFORMANCE

Initial Reserve Balance	Annual Reserve Accrual	Expected Reserve Balance at end of 5 years	Probability of negative balance within 5 years
($ millions)	($ millions)	($ millions)	%
$27	$3.5	$11	29%

Figure 5-1 below shows the results of the Reserve fund performance analysis. These results show the mean (expected) Reserve fund balance as well as the 5th and 95th percentiles.

For example, given an initial Reserve balance of $27 million and an Annual Accrual of $3.5 million, Figure 5-1 illustrates the expected performance of the Reserve. The Reserve has a mean (expected) balance of $11 at the end of the five year period. The 5th percentile and 95th percentile 5 year ending Reserve balances are $51 million and negative $(111) million respectively. The Reserve fund has a 29% chance of having a negative balance in one or more years of the five year simulation.

The first year of each simulation begins with a $27 million Reserve balance. The first year's annual accrual will bring the reserve balance to $30.5 million. Table 5-1, shows that the likelihood of hurricane damage exceeding $30 million in a single year is about 8%.

The accrual of $3.5 million is less than the Reserve obligation of the Expected Annual Damage from hurricanes of $6.8 million. Therefore with each passing year, the Reserve ending balance has a decreasing likelihood of accumulating surpluses. The expected (mean) Reserve balance declines gradually over the five year simulation to $11 million at five years reflecting the annual accrual less than the expected annual damage. At the end of five years, the likelihood of annual hurricane damage in excess of $11 million is approximately 15%, about double the likelihood at the beginning of the simulation.

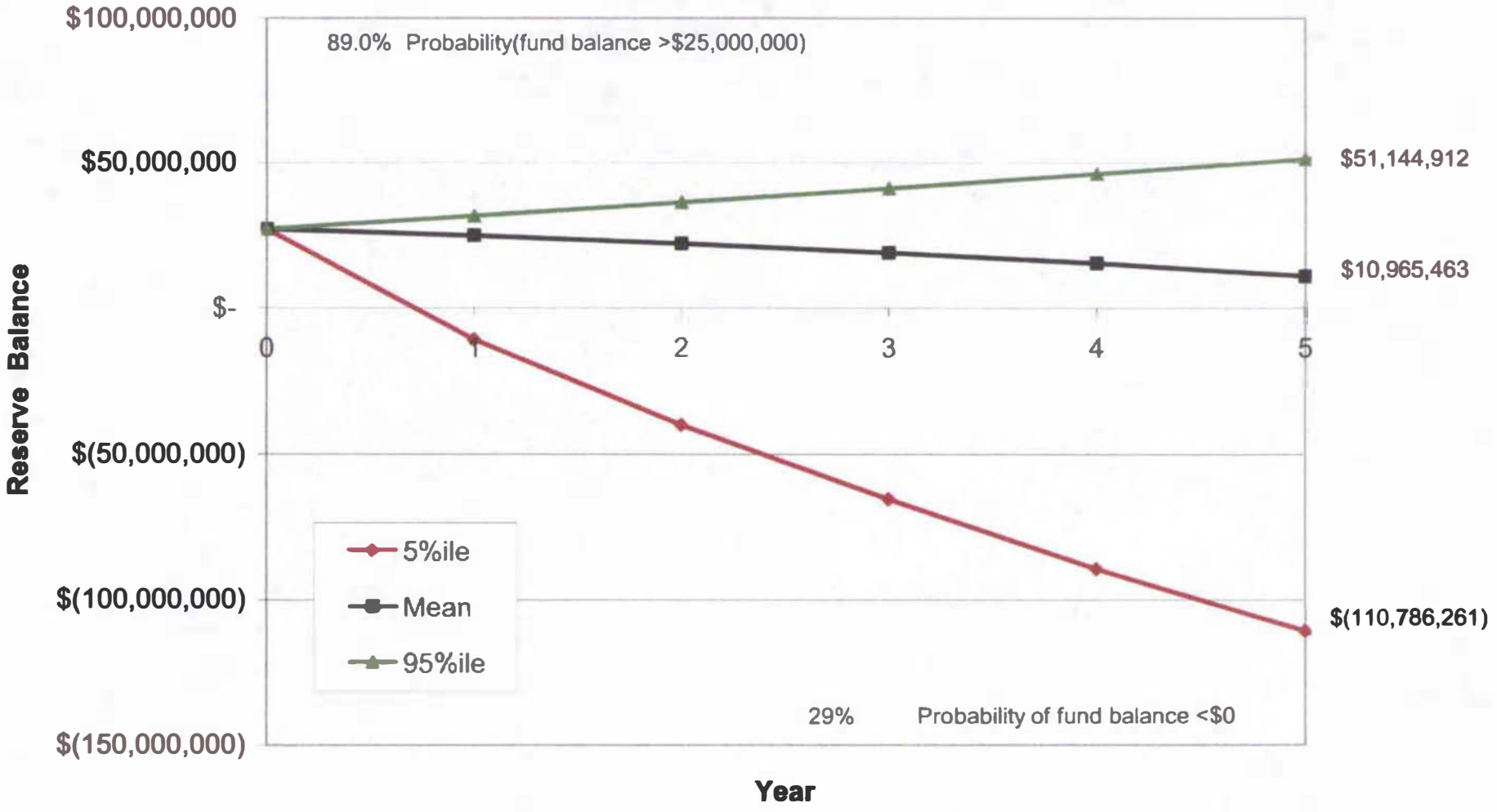

Figure 5-1: Reserve Performance Analysis Results: $27 million Initial Balance, $3.5 million Annual Accrual

6. References

1. "Florida Commission on Hurricane Loss Projection Methodology", EQECAT, an ABS Group Company, May 18, 2009.

EQECAT
An ABS Group Company

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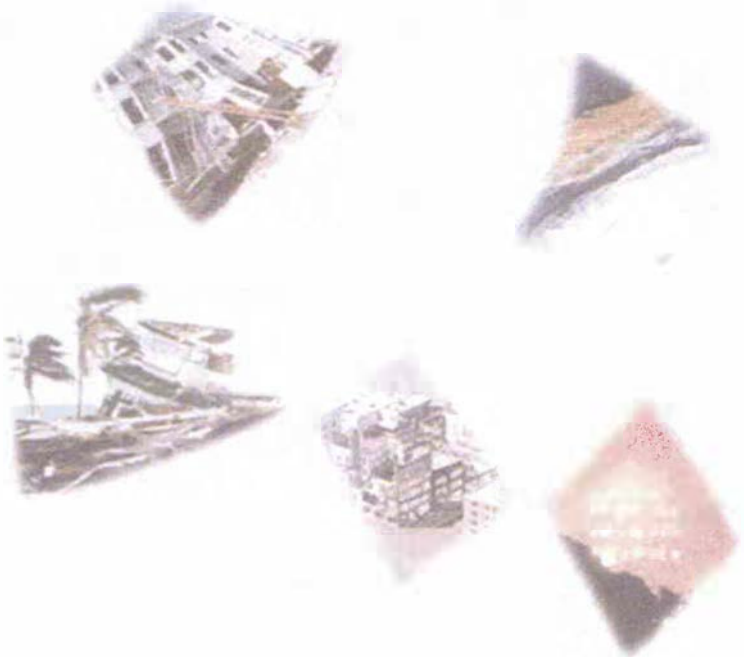

Gulf Power's 2013 Depreciation Study was filed on May 24, 2013 in Docket No. 130151 and is incorporated herein by reference. Gulf's 2013 Depreciation Study is identified in the Commission's records as Document Numbers 02867-13 and 02868-13.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130140-EI EXHIBIT 19
PARTY Gulf Power Company (Gulf) Direct
DESCRIPTION Peter S. Huck (PSH-1)
DATE

Responsibility for Minimum Filing Requirements

Schedule	Title
B-4	Two Year Historical Balance Sheet
B-21	Accumulated Provision Accounts – 228.1, 228.2 and 228.4
B-22	Total Accumulated Deferred Income Taxes
B-23	Investment Tax Credits – Annual Analysis
B-24	Leasing Arrangements
B-25	Accounting Policy Changes Affecting Rate Base
C-6	Budgeted Versus Actual Operating Revenues and Expenses
C-8	Detail of Changes in Expenses
C-9	Five Year Analysis – Change in Cost
C-10	Detail of Rate Case Expenses for Outside Consultants
C-12	Administrative Expenses
C-13	Miscellaneous General Expenses
C-15	Industry Association Dues
C-16	Outside Professional Services
C-17	Pension Cost
C-18	Lobbying Expenses, Other Political Expenses and Civic/Charitable Contributions
C-19	Amortization/Recovery Schedule – 12 Months
C-20	Taxes Other than Income Taxes
C-21	Revenue Taxes

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130140-EI EXHIBIT 20
PARTY Gulf Power Company (Gulf) Direct
DESCRIPTION Constance J. Erickson (CJE-1)
DATE

Responsibility for Minimum Filing Requirements

Schedule	Title
C-22	State and Federal Income Tax Calculation
C-25	Deferred Tax Adjustment
C-26	Income Tax Returns
C-27	Consolidated Tax Information
C-28	Miscellaneous Tax Information
C-29	Gains and Losses on Disposition of Plant or Property
C-30	Transactions with Affiliated Companies
C-31	Affiliated Company Relationships
C-41	O&M Benchmark Variance by Function
C-43	Security Costs
F-1	Annual and Quarterly Reports to Shareholders
F-2	SEC Reports
F-8	Assumptions

Florida Public Service Commission
Docket No. 130140-EI
GULF POWER COMPANY
Witness: Connie J. Erickson
Exhibit No. ____ (CJE-1)
Schedule 2
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A&G Budgeted Expenses
($000's)

FERC Account	Description	2013	2014	2015	2016	2017
920	Administrative and General Salaries	15,690	16,145	16,702	17,256	17,733
921	Office Supplies and Expenses	4,014	4,097	4,128	4,146	4,174
922	Administrative Expenses Transferred - Credit	(333)	(342)	(353)	(363)	(374)
923	Outside Services Employed	18,061	18,948	19,626	20,058	20,594
924	Property Insurance	7,487	13,467	13,629	13,706	13,706
925	Injuries and Damages	3,117	3,162	3,187	3,240	3,292
926	Employee Pensions & Benefits	23,539	24,485	24,544	24,784	24,184
928	Regulatory Commission Expenses	2,091	3,079	3,142	3,209	3,280
929	Duplicate Charges - Credit	(1,027)	(1,054)	(1,079)	(1,105)	(1,133)
930	General Advertising/Miscellaneous General Expenses	6,738	6,841	6,633	7,176	6,990
931	Rents	364	252	258	264	271
935	Maintenance of General Plant	724	687	717	720	724
	Total	**80,465**	**89,767**	**91,134**	**93,091**	**93,441**

The amounts for 2014-2017 include NOI adjustments discussed in Ms. Ritenour's testimony.

A&G - Benchmark Variance

	($000)
Test Year Adjusted Benchmark	78,744
Test Year Adjusted Request	89,767
System Benchmark Variance	11,023

Description	Variance
Pension Expense	5,871
Property Damage Accrual	5,249
Rate Case Expense	880
	12,000

Florida Public Service Commission
Docket No. 130140-EI
GULF POWER COMPANY
Witness: Connie J. Erickson
Exhibit No. ____ (CJE-1)
Schedule 4
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Function ($000's)		Total Adjusted Utility Depreciation and Dismantlement Base Rate Expense net of UPS	2014 Calculated Base Rate Expense Using Proposed Rates	2014 Company NOI Adjustment
Depreciation				
Steam	$	31,153	31,047	(106)
Other Production	$	7,229	10,764	3,535
Transmission	$	12,914	13,239	325
Distribution	$	41,189	39,879	(1,310)
General	$	5,711	5,466	(245)
Intangible	$	2,294	2,294	-
Total Depreciation	**$**	**100,490**	**102,689**	**2,199**
Dismantlement				
Steam	$	4,788	2,241	(2,547)
Other Production	$	301	352	51
Total Dismantlement	**$**	**5,089**	**2,593**	**(2,496)**
Total Depreciation and Dismantlement	**$**	**105,579**	**105,282** *	**(297)**

*Amount does not equal depreciation and amortization on MFR C-1 as it does not include amortization related to regulatory assets.

Gulf Power's 2013 Dismantling Study was filed on May 24, 2013 in Docket No. 130151 and is incorporated herein by reference. Gulf's 2013 Dismantling Study is identified in the Commission's records as Document Numbers 02869-13 and 02870-13.

Responsibility for Minimum Filing Requirements

Schedule	Title
C-6	Budgeted Versus Actual Operating Revenues and Expenses
C-7	Operation and Maintenance Expenses – Test Year
C-30	Transactions with Affiliated Companies
C-33	Performance Indices
C-35	Payroll and Fringe Benefit Increases Compared to CPI
C-36	Non-Fuel Operation and Maintenance Expense Compared to CPI
C-37	O&M Benchmark Comparison by Function
C-38	O&M Adjustments by Function
C-39	Benchmark Year Recoverable O&M Expenses by Function
C-40	O&M Compound Multiplier Calculation
C-41	O&M Benchmark Variance by Function
C-43	Security Costs

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130140-EI EXHIBIT 21
PARTY Gulf Power Company (Gulf) Direct
DESCRIPTION Richard M. McMillan (RJM-1)
DATE

OPERATION AND MAINTENANCE EXPENSES
BENCHMARK VARIANCE BY FUNCTION
2012 ALLOWED COMPARED TO TEST YEAR REQUEST EXPENSES

(1) Line No.	(2) Description	(3) 2012 Allowed	(4) Compound Multiplier	(5) Test Year Benchmark (3) X (4)	(6) Test Year Request	(7) Variance
1	Steam Production	95,311	1.05007	100,083	91,723	(8,360)
2	Other Production	7,312	1.05007	7,678	11,142	3,464
3	Other Power Supply	4,312	1.05007	4,528	3,871	(657)
4	Total Production	106,935	1.05007	112,289	106,736	(5,553)
5	Transmission	11,320	1.07161	12,131	13,733	1,602
6	Distribution	39,877	1.07161	42,733	42,070	(663)
7	Customer Accounts	24,532	1.07161	26,289	25,795	(494)
8	Customer Service & Information	18,861	1.07161	20,212	16,644	(3,568)
9	Sales	945	1.07161	1,013	1,171	158
10	Administrative & General	73,482	1.07161	78,744	89,767	11,023
11	2012 Allowed O&M Compared to Test Year O&M Request	275,952		293,411	295,916	2,505

Note: Total O&M less Fuel, Purchased Power, ECCR, ECRC and Other Regulatory Adjustments

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BENCHMARK YEAR RECOVERABLE O&M EXPENSES BY FUNCTION

(1) Line No.	(2) Function	(3) 2012 System Per Books	(4) Eliminate Recoverable Fuel and Purchased Power	(5) Eliminate Recoverable ECRC	(6) Eliminate Recoverable ECCR	(7) Other Regulatory O&M Adjustments	(8) Function Adjustments	(9) 2012 Adjusted System Amount
1	Production	882,030	(730,362)	(30,440)	0	(14,293)	0	106,935
2	Transmission	14,269	(2,657)	0	0	(292)	0	11,320
3	Distribution	43,781	0	(2,185)	0	(1,032)	(687)	39,877
4	Customer Accounts	24,723	0	0	0	(1,054)	863	24,532
5	Customer Service & Information	38,757	0	0	(18,070)	(465)	(1,361)	18,861
6	Sales Expense	1,097	0	0	0	(152)	0	945
7	Administrative & General	82,178	(300)	(706)	(1,241)	(7,634)	1,185	73,482
8	Total O&M Expenses by Function	1,086,835	(733,319)	(33,331)	(19,311)	(24,922)	0	275,952

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TEST YEAR O&M ADJUSTMENTS BY FUNCTION

(1) Line No.	(2) Function	(3) Test Year System Per Books	(4) Direct Fuel, Fuel-Related Expenses and Purchased Power	(5) ECCR	(6) ECRC	(7) Tallahassee Liaison Expenses	(8) Plant Scherer/ UPS	(9) Marketing Support Activities	(10) Management Financial Planning	(11) Economic Development
1	Production									
2	Steam Production	431,622	(303,538)		(24,672)		(10,072)			
3	Other Production	321,851	(310,241)		(51)					
4	Other Power Supply	92,144	(88,018)							
5	Total Production	845,617	(701,797)	0	(24,723)	0	(10,072)	0	0	0
6	Transmission	27,386	(13,624)		(9)		(4)			
7	Distribution	45,738			(3,576)					
8	Customer Accounts	25,850								
9	Customer Service & Information	38,602		(21,931)						
10	Sales Expenses	1,391						(156)		(62)
11	Administrative & General	88,996	(100)	(1,589)	(769)	(306)	(2,616)		(41)	(1)
12	Total Adjustments	1,073,580	(715,521)	(23,520)	(29,077)	(306)	(12,692)	(156)	(41)	(63)

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TEST YEAR O&M ADJUSTMENTS BY FUNCTION

(1) Line No.	(2) Function	(3) Wholesale Sales Expense	(4) Advertising	(5) Rate Case Expenses	(6) Property Insurance Reserve	(7) Hiring Lag	(8) Perdido Unit 3	(9) Plant Scholz	(10) Subtotal Adjustments	(11) Total Adjusted O&M
1	Production									
2	Steam Production					(142)		(1,475)	(339,899)	91,723
3	Other Production					(17)	(400)		(310,709)	11,142
4	Other Power Supply	(255)							(88,273)	3,871
5	Total Production	0	0	0	0	(159)	(400)	(1,475)	(738,881)	106,736
6	Transmission					(16)			(13,653)	13,733
7	Distribution					(92)			(3,668)	42,070
8	Customer Accounts					(55)			(55)	25,795
9	Customer Service & Information					(27)			(21,958)	16,644
10	Sales Expenses					(2)			(220)	1,171
11	Administrative & General		(30)	930	5,500	(207)			771	89,767
12	Total Adjustments	(255)	(30)	930	5,500	(558)	(400)	(1,475)	(777,664)	295,916

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HIRING LAG

	Average Turnover	Average # of Days to Hire	Average Salary	Average Hiring Lag
Covered	20	45	$ 27,402	$ 67,567
Exempt	26	59	$ 86,696	$ 364,361
Non-Exempt	13	60	$ 40,835	$ 87,264
				$ 519,191

Average Hiring Lag	$ 519,191
O&M Percentage	72.00%
Average Hiring Lag - O&M	$ 373,818
Benefits - 33.74%	$ 126,126
Variable Compensation - 15.46%	$ 57,792
Average Hiring Lag, incl. Benefits and Var. Comp.	$ 557,736

Average Turnover and Average Days to Hire details are shown below.
Average Salary - based on average salaries for 2012.
Fringe Benefits and Variable Compensation rates calculated using MFR C-35.

Employee Turnover *

Year	Covered	Exempt	Non-Exempt NC	Total
2009	12	20	9	41
2010	25	42	12	79
2011	19	21	11	51
2012	24	19	18	61
Avg	20	26	13	58

** Includes voluntary and involuntary terminations, retirements and transfers within the Southern Company.*

Average # of Days to Hire

Year	Covered	Exempt	Non-Exempt NC	Total
2009	53	45	62	55
2010	37	57	52	46
2011	50	65	63	60
2012	42	68	62	53
Avg	45	59	60	53

Responsibility for Minimum Filing Requirements

Schedule	Title
A-1	Full Revenue Requirements Increase Requested
A-4	Interim Revenue Requirements Increase Requested
B-1	Adjusted Rate Base
B-2	Rate Base Adjustments
B-3	13 Month Average Balance Sheet - System Basis
B-5	Detail Of Changes In Rate Base
B-7	Plant Balances By Account And Sub-Account
B-8	Monthly Plant Balances Test Year - 13 Months
B-9	Depreciation Reserve Balances By Account And Sub-Account
B-10	Monthly Reserve Balances Test Year - 13 Months
B-11	Capital Additions And Retirements
B-12	Production Plant Additions
B-13	Construction Work In Progress
B-14	Earnings Test
B-15	Property Held For Future Use - 13 Month Average
B-17	Working Capital - 13 Month Average
B-18	Fuel Inventory By Plant
B-19	Miscellaneous Deferred Debits
B-20	Other Deferred Credits
B-25	Accounting Policy Changes Affecting Rate Base
C-1	Adjusted Jurisdictional Net Operating Income

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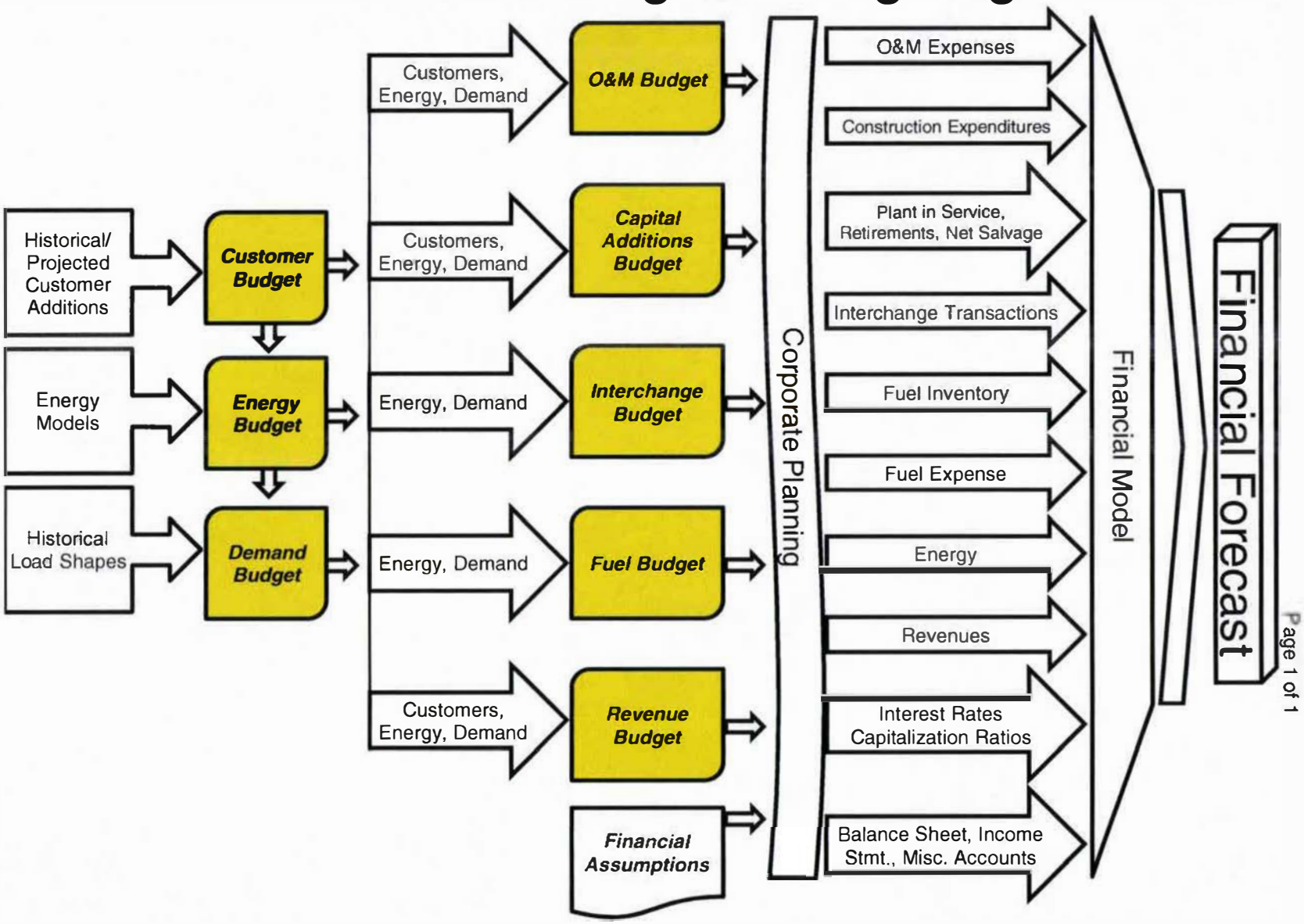
PARTY Gulf Power Company (Gulf) Direct
DESCRIPTION Susan R. Ritenour (SDR-1)
DATE

C-2	Net Operating Income Adjustments
C-3	Jurisdictional Net Operating Income Adjustments
C-5	Operating Revenues Detail
C-6	Budgeted Versus Actual Operating Revenues And Expenses
C-19	Amortization/Recovery Schedule - 12 Months
C-23	Interest In Tax Expense Calculation
C-29	Gains And Losses On Disposition Of Plant Or Property
C-32	Non-Utility Operations Utilizing Utility Assets
C-44	Revenue Expansion Factor
D-1a	Cost Of Capital - 13 Month Average
D-1b	Cost Of Capital - Adjustments
D-2	Cost Of Capital - 5 Year History
D-3	Short-Term Debt
D-4a	Long-Term Debt Outstanding
D-4b	Reacquired Bonds
D-5	Preferred Stock Outstanding
D-6	Customer Deposits
D-7	Common Stock Data
D-8	Financial Plans - Stocks And Bond Issues
D-9	Financial Indicators - Summary
F-5	Forecasting Models
F-8	Assumptions

Gulf Power Planning and Budgeting Process



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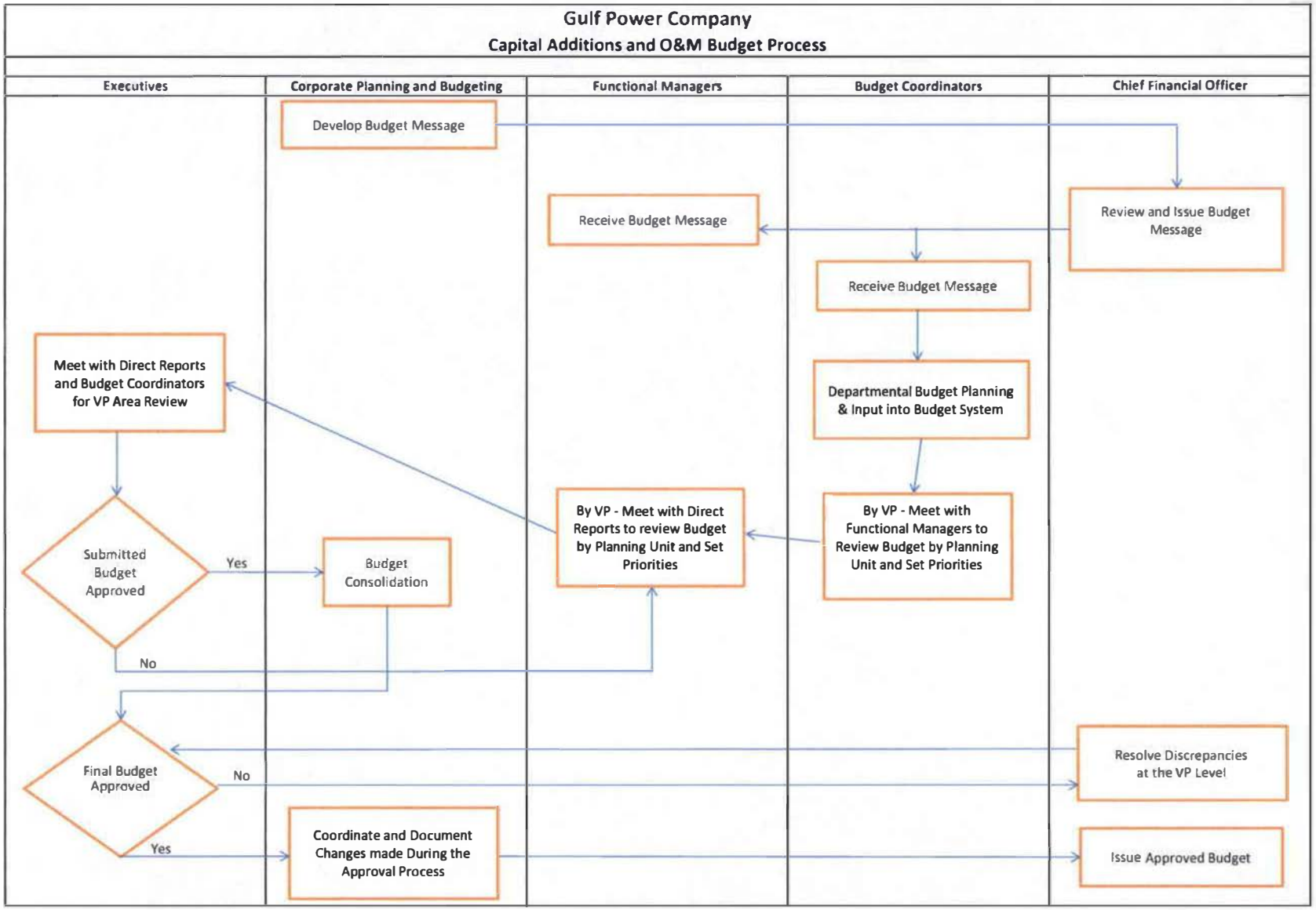
Gulf Power Company
Capital Additions and O&M Budget Process



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GULF POWER COMPANY

2014 Test Year Capital Additions Budget
By Function
($ 000's)

Function	Test Year System Per Books	Test Year Total Adjusted	*	Witness
Production	302,424	38,384		Grove
Transmission	114,936	114,936		Caldwell
Distribution	52,174	45,348	**	McQuagge
General	8,448	8,289		Ritenour
TOTAL	**477,982**	**206,957**		

*Amounts exclude capital expenditures for wholesale, clauses, and non-utility
**Amount reflects reduction in New Business Distribution capital expenditures

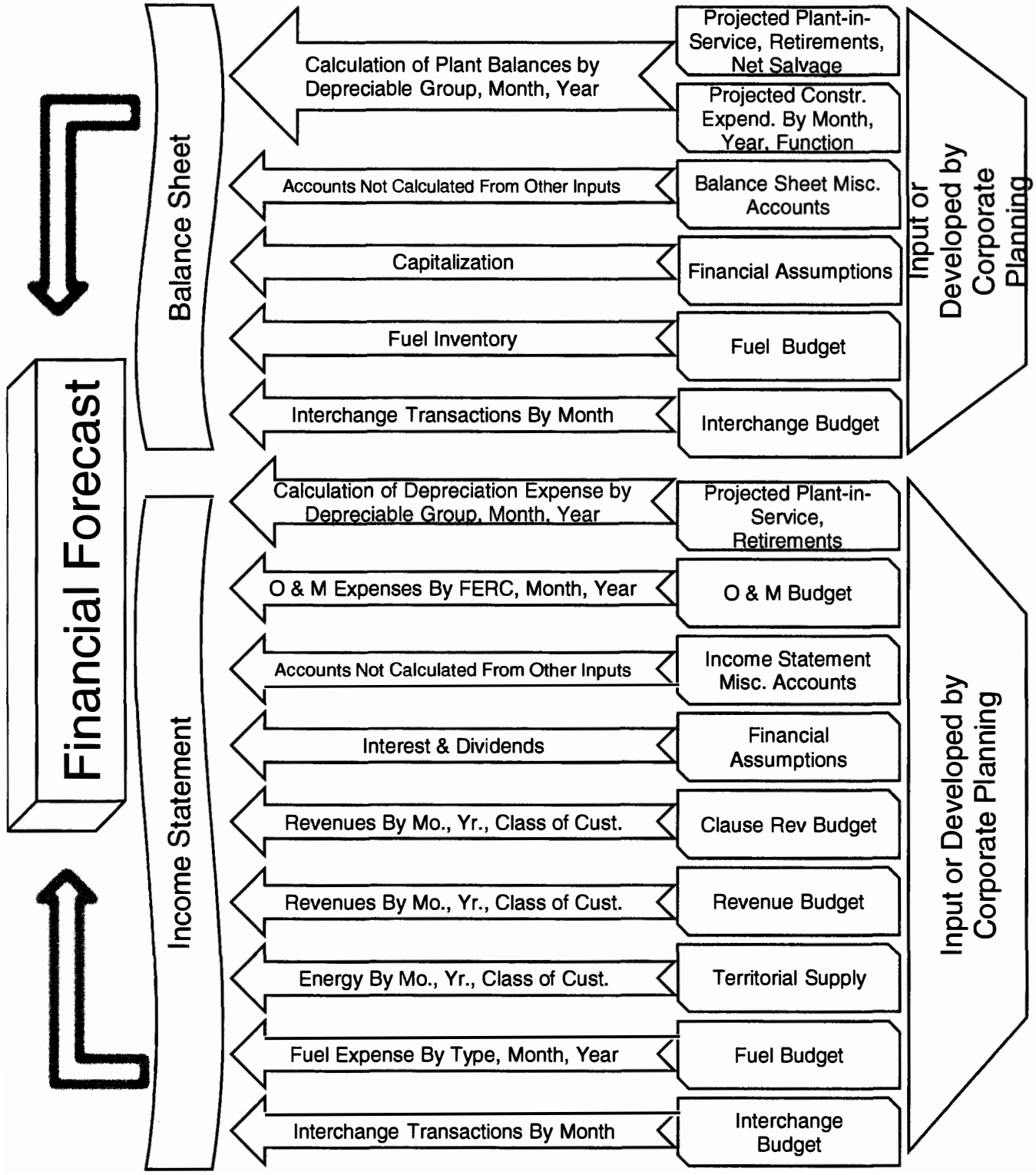
GULF POWER COMPANY

2014 Test Year Operation and Maintenance Expense
By Function
($ 000's)

Function	Test Year System Per Books	Test Year Total Adjusted *	Witness
Production	845,617	106,736	Grove
Transmission	27,386	13,733	Caldwell
Distribution	45,738	42,070	McQuagge
Customer Accounts	25,850	25,795	Neyman
Customer Service & Information	38,602	16,644	Strickland
Sales Expenses	1,391	1,171	Strickland
Administrative & General	88,996	89,767	Erickson, Garvie
Total Operation and Maintenance	**1,073,580**	**295,916**	

* As reflected on exhibit RJM-1, Schedule 4 of Mr. McMillan's testimony.

Gulf Power Financial Model Flowchart



GULF POWER COMPANY
BALANCE SHEET
For the Period December 2013 through December 2014
($000)

	2013 DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	2014 DEC
ASSETS:													
Utility Plant													
Electric Plant in Service	4,689,271	4,725,430	4,762,846	4,805,250	4,844,262	4,876,026	4,908,734	4,940,789	4,972,708	5,010,318	5,054,074	5,101,166	5,145,368
Accum Prov & Amort	1,485,261	1,495,382	1,503,891	1,514,150	1,525,321	1,537,277	1,549,055	1,560,514	1,572,245	1,583,764	1,595,333	1,606,459	1,615,470
Net Elec & Plant In Service	**3,204,010**	**3,230,048**	**3,258,955**	**3,291,100**	**3,318,941**	**3,338,749**	**3,359,679**	**3,380,275**	**3,400,463**	**3,426,554**	**3,458,741**	**3,494,707**	**3,529,898**
Other Property & Investments													
Other Special Funds	101,452	102,543	101,786	101,029	100,278	99,528	98,777	98,034	97,292	96,549	95,813	95,077	94,341
Non-Utility Property-Net	13,055	13,051	13,047	13,043	13,038	13,034	13,030	13,025	13,021	13,016	13,011	13,007	13,002
Other Property & Investments	2,588	2,589	2,590	2,592	2,593	2,595	2,597	2,598	2,600	2,603	2,606	2,609	2,612
Total Other Property & Invest	**117,095**	**118,183**	**117,423**	**116,664**	**115,909**	**115,157**	**114,404**	**113,657**	**112,913**	**112,168**	**111,430**	**110,693**	**109,955**
Current Assets													
Cash & Cash Equivalents	6,011	6,011	6,011	6,011	6,011	6,011	6,011	6,011	6,011	6,011	6,011	6,011	6,011
Special Deposits	18	18	18	18	18	18	18	18	18	18	18	18	18
Working Funds	378	378	379	379	378	378	378	379	378	378	379	379	379
Temporary Cash Investments	0	0	0	0	0	0	0	0	0	0	0	0	0
Accounts & Notes Receivable:													
Customer Accounts Receivable	68,099	76,272	75,591	62,318	62,731	63,521	79,831	90,322	88,194	97,255	83,301	68,472	72,615
Accrued Unbilled Revenues	54,079	52,567	43,950	44,696	44,641	59,262	64,950	67,807	68,224	58,458	47,235	49,618	54,870
Other Accts\Notes Receivable	11,859	13,148	13,003	12,857	12,712	12,567	12,422	12,588	12,442	12,296	12,151	12,005	11,859
Accum Prov for Uncoll Accts	1,799	2,242	2,220	1,708	1,510	1,440	1,426	1,593	1,588	1,933	1,768	1,478	1,910
Rec. From Assoc. Companies	15,684	14,742	13,006	11,306	10,640	8,542	12,263	17,544	20,586	16,009	10,299	12,289	10,946
Interest & Dividends Receivable	9	15	16	16	23	23	23	30	31	31	37	37	37
Materials & Supplies:													
Fuel Stock	110,709	105,275	104,992	103,413	101,588	100,584	95,837	88,022	81,593	76,908	73,083	74,747	77,277
In-Transit Coal	12,770	10,562	12,855	12,579	12,855	11,020	11,020	10,561	10,562	11,020	11,020	10,562	10,562
Plt Materials & Supplies	60,820	60,653	60,506	60,345	60,179	60,007	60,262	60,805	60,610	60,418	60,240	60,084	59,954
Prepayments	13,506	13,919	14,201	14,483	14,764	16,132	16,411	16,689	17,062	17,341	17,619	22,575	22,838
Misc Current & Accrued Assets	4,357	4,357	4,357	4,357	4,357	4,357	4,357	4,360	4,357	4,357	4,357	4,357	4,357
Total Current Assets	**356,500**	**355,675**	**346,665**	**331,070**	**329,387**	**340,982**	**362,357**	**373,543**	**368,480**	**358,567**	**323,982**	**319,676**	**329,813**
Deferred Debits													
Unamortized Debt Expense	7,721	7,677	7,632	7,588	7,543	7,499	7,454	7,410	7,365	7,321	7,278	7,235	7,192
Accum Deferred Income Tax	74,155	74,565	74,975	75,385	75,795	76,205	76,615	77,025	77,435	77,845	78,255	78,665	79,075
Regulatory Tax Asset	49,216	49,750	50,283	50,817	51,350	51,884	52,417	52,951	53,485	54,018	54,552	55,085	55,619
Unamortized Loss Reacq Debt	15,048	14,937	14,827	14,717	14,607	14,497	14,386	14,276	14,166	14,056	13,946	13,836	13,732
Other Deferred Debits	467,838	469,813	471,565	472,872	474,750	474,351	471,936	470,090	468,019	465,605	463,759	461,689	459,563
Total Deferred Debits	**613,978**	**616,742**	**619,282**	**621,379**	**624,045**	**624,436**	**622,808**	**621,752**	**620,470**	**618,845**	**617,790**	**616,510**	**615,181**
Total Assets	**4,291,583**	**4,320,648**	**4,342,325**	**4,360,213**	**4,388,282**	**4,419,324**	**4,459,248**	**4,489,227**	**4,502,326**	**4,516,134**	**4,511,943**	**4,541,586**	**4,584,847**

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GULF POWER COMPANY
Witness: Susan D. Ritenour
Exhibit No. _____ (SDR-1)
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GULF POWER COMPANY
BALANCE SHEET
For the Period December 2013 through December 2014
($000)

	2013 DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	2014 DEC
CAPITALIZATION & LIABILITIES:													
Common Equity													
Common Stock	393,060	393,060	393,060	393,060	393,060	393,060	393,060	393,060	393,060	393,060	393,060	393,060	393,060
Other Paid-In Capital	596,782	717,681	717,931	720,072	720,210	720,353	721,813	721,952	722,090	723,545	723,680	723,761	725,213
Capital Stock Expense	0	0	0	0	0	0	0	0	0	0	0	0	0
Retained Earnings	244,364	223,890	227,819	232,528	206,210	215,250	229,230	216,327	233,142	245,931	220,489	224,274	231,360
Total Common Equity	**1,234,206**	**1,334,631**	**1,338,810**	**1,345,660**	**1,319,480**	**1,328,663**	**1,344,103**	**1,331,339**	**1,348,292**	**1,362,536**	**1,337,229**	**1,341,095**	**1,349,633**
Preference Stock													
Preference Stock	147,998	147,998	147,998	147,998	147,998	147,998	147,998	147,998	147,998	147,998	147,998	147,998	147,998
Trust Preferred Stock	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Preferred Stock	**147,998**	**147,998**	**147,998**	**147,998**	**147,998**	**147,998**	**147,998**	**147,998**	**147,998**	**147,998**	**147,998**	**147,998**	**147,998**
Debt													
Pollution Control Bonds	308,955	308,955	308,955	308,955	308,955	308,955	308,955	308,955	308,955	308,955	308,955	308,955	308,955
Long-Term Notes	940,000	940,000	940,000	940,000	1,010,000	1,010,000	1,010,000	1,010,000	1,010,000	1,010,000	1,075,000	1,075,000	1,075,000
Unamortized Premiums & Disc	(7,498)	(7,451)	(7,404)	(7,356)	(7,309)	(7,262)	(7,215)	(7,167)	(7,120)	(7,073)	(7,030)	(6,987)	(6,944)
Total Debt	**1,241,457**	**1,241,504**	**1,241,551**	**1,241,599**	**1,311,646**	**1,311,693**	**1,311,740**	**1,311,788**	**1,311,835**	**1,311,882**	**1,376,925**	**1,376,968**	**1,377,011**
Total Capitalization	**2,623,661**	**2,724,133**	**2,728,359**	**2,735,257**	**2,779,124**	**2,788,354**	**2,803,841**	**2,791,125**	**2,808,125**	**2,822,416**	**2,862,152**	**2,866,061**	**2,874,642**
Current Liabilities													
Short-Term Notes Payable	119,499	3,321	17,213	61,364	19,848	21,280	73,858	62,364	44,240	82,705	3,467	38,293	124,165
Accounts Payable:													
Construction Related Accts Payable	7,110	12,507	13,177	14,484	13,068	10,363	10,676	10,427	10,207	11,432	13,665	15,215	13,095
Other Accounts Payable	59,900	63,965	58,897	59,292	59,493	59,500	59,510	59,469	60,590	59,451	65,490	64,246	60,035
Payables to Assoc. Companies	42,841	37,132	31,721	31,752	30,293	36,222	38,356	47,485	42,139	40,502	36,221	38,333	41,155
Total Accounts Payable	**109,851**	**113,604**	**103,795**	**105,528**	**102,854**	**106,085**	**108,542**	**117,381**	**112,936**	**111,385**	**115,376**	**117,794**	**114,285**
Customer Deposits	35,075	35,136	35,191	35,239	35,286	35,334	35,396	35,441	35,476	35,477	35,482	35,498	35,519
Taxes Accrued	2,478	7,102	8,086	9,522	3,314	7,394	7,504	16,674	25,552	17,288	18,487	19,069	2,478
Interest Accrued	9,290	12,603	16,404	13,555	11,870	16,258	9,912	12,571	16,801	14,247	12,007	16,741	11,650
Dividends Declared	2,196	30,856	31,596	2,196	30,856	31,596	2,196	30,856	31,596	2,196	30,856	31,596	2,196
Accrued Vacations	9,651	9,651	9,651	9,651	9,651	9,651	9,651	9,651	9,651	9,651	9,651	9,651	9,941
Tax Collections Payable	7,862	4,594	6,639	8,236	10,087	12,369	15,979	18,652	21,620	24,330	26,361	6,952	8,457
Other Current Liabilities	42,575	44,168	45,302	35,207	36,379	36,883	37,904	38,921	39,938	39,663	40,587	41,607	42,891
Total Current Liabilities	**338,477**	**261,035**	**273,877**	**280,498**	**260,145**	**276,850**	**300,942**	**342,511**	**337,810**	**336,942**	**292,274**	**317,201**	**351,582**
Deferred Credits													
Unamortized ITC	4,106	4,002	3,900	3,798	3,696	3,594	3,492	3,390	3,288	3,186	3,084	2,982	2,880
Other Deferred Credits	273,428	276,650	278,463	280,035	281,788	284,094	281,635	279,951	277,943	275,501	273,425	271,417	268,890
Total Deferred Credits	**277,534**	**280,652**	**282,363**	**283,833**	**285,484**	**287,688**	**285,127**	**283,341**	**281,231**	**278,687**	**276,509**	**274,399**	**271,770**

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GULF POWER COMPANY
Witness: Susan D. Ritenour
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GULF POWER COMPANY
BALANCE SHEET
For the Period December 2013 through December 2014
($000)

	2013 DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	2014 DEC
Operating Reserves													
Property Insurance Reserve	35,094	35,363	35,635	35,906	36,183	36,461	36,739	37,025	37,310	37,596	37,888	38,180	38,473
Injuries & Damages Reserve	3,256	3,272	3,288	3,304	3,321	3,337	3,353	3,369	3,386	3,402	3,418	3,434	3,451
Accum Prov for Rate Refunds	0	0	0	0	0	0	0	0	0	0	0	0	0
Empl Pension & Insurance Reserve	224,240	224,400	224,537	224,676	224,813	224,950	225,089	225,226	225,362	225,516	225,654	225,791	225,929
Asset Retirement Reserve	16,055	16,055	16,055	16,055	16,055	16,055	16,055	16,055	16,055	16,055	16,055	16,055	16,055
Total Operating Reserves	**278,645**	**279,090**	**279,515**	**279,941**	**280,372**	**280,803**	**281,236**	**281,675**	**282,113**	**282,569**	**283,015**	**283,460**	**283,908**
Deferred Tax Related Items													
ADIT Accts 281, 282, 283	768,139	770,713	773,287	775,861	778,435	781,009	783,583	786,157	788,731	791,305	793,879	796,453	799,034
Regulatory Tax Liability	5,127	5,025	4,924	4,823	4,722	4,620	4,519	4,418	4,316	4,215	4,114	4,012	3,911
Total Deferred Taxes	**773,266**	**775,738**	**778,211**	**780,684**	**783,157**	**785,629**	**788,102**	**790,575**	**793,047**	**795,520**	**797,993**	**800,465**	**802,945**
Total Capital & Liabilities	**4,291,583**	**4,320,648**	**4,342,325**	**4,360,213**	**4,388,282**	**4,419,324**	**4,459,248**	**4,489,227**	**4,502,326**	**4,516,134**	**4,511,943**	**4,541,586**	**4,584,847**

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GULF POWER COMPANY
Witness: Susan D. Ritenour
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GULF POWER COMPANY
INCOME STATEMENT
For the Twelve Months Ended December 31, 2014
($000)

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	12 MONTHS ENDED DEC 2014
OPERATING REVENUES:													
Residential													
Base	25,724	21,257	20,640	19,622	25,391	29,679	32,379	31,588	27,418	22,165	20,116	23,835	**299,814**
Fuel	22,448	16,942	16,008	15,687	21,503	25,630	27,815	27,156	22,675	17,915	15,793	19,822	**249,394**
Conservation	911	900	997	939	1,025	1,311	1,148	1,134	1,201	923	904	1,030	**12,423**
Capacity	1,497	1,497	1,444	1,444	1,761	3,715	3,130	3,915	3,687	3,923	3,816	3,866	**33,695**
Environmental	5,609	5,807	6,249	5,632	5,832	6,049	5,806	5,932	5,905	5,710	5,752	6,055	**70,338**
Total Residential Revenues	**56,189**	**46,403**	**45,338**	**43,324**	**55,512**	**66,384**	**70,278**	**69,725**	**60,886**	**50,636**	**46,381**	**54,608**	**665,664**
Commercial													
Base	12,450	11,244	12,012	12,004	13,721	14,233	15,032	15,077	14,147	13,370	11,955	12,168	**157,413**
Fuel	15,161	12,816	14,222	15,053	17,704	18,373	19,222	19,271	17,503	16,467	13,905	14,391	**194,088**
Conservation	615	681	886	901	844	939	794	804	927	848	796	747	**9,782**
Capacity	811	811	783	783	954	2,013	1,697	2,122	1,998	2,126	2,068	2,095	**18,261**
Environmental	3,466	3,587	3,859	3,473	3,597	3,733	3,584	3,660	3,639	3,519	3,531	3,718	**43,366**
Total Commercial Revenues	**32,503**	**29,139**	**31,762**	**32,214**	**36,820**	**39,291**	**40,329**	**40,934**	**38,214**	**36,330**	**32,255**	**33,119**	**422,910**
Industrial													
Base	2,478	2,192	2,509	2,567	2,798	4,051	4,591	4,681	4,557	2,817	2,435	2,465	**38,141**
Fuel	6,355	5,271	6,249	6,603	7,496	7,180	7,850	8,021	7,132	7,274	6,326	6,164	**81,921**
Conservation	258	279	389	395	357	367	325	335	378	375	362	320	**4,140**
Capacity	366	366	353	353	430	908	765	957	901	959	933	945	**8,236**
Environmental	2,741	2,838	3,054	2,745	2,841	2,952	2,834	2,894	2,875	2,779	2,780	2,926	**34,259**
Total Industrial Revenues	**12,198**	**10,946**	**12,554**	**12,663**	**13,922**	**15,458**	**16,365**	**16,888**	**15,843**	**14,204**	**12,836**	**12,820**	**166,697**
Street Lighting													
Base	260	260	260	260	260	260	260	260	260	260	260	261	**3,121**
Fuel	106	100	101	103	103	100	98	98	98	103	101	102	**1,213**
Conservation	4	5	6	6	5	5	4	4	5	5	6	5	**60**
Capacity	2	2	2	2	3	5	4	6	5	6	5	5	**47**
Environmental	108	113	121	108	112	117	111	114	113	109	109	114	**1,349**
Total Street Lighting Revenues	**480**	**480**	**490**	**479**	**483**	**487**	**477**	**482**	**481**	**483**	**481**	**487**	**5,790**
Additional Gross Receipts Tax	2,640	2,453	2,294	2,277	2,364	2,975	3,197	3,275	3,212	2,896	2,298	2,460	**32,341**
Tot Base Revenues (incl Gross Recpts)	43,552	37,406	37,715	36,730	44,534	51,198	55,459	54,881	49,594	41,508	37,064	41,189	**530,830**
Tot Fuel Revenues	44,070	35,129	36,580	37,446	46,806	51,283	54,985	54,546	47,408	41,759	36,125	40,479	**526,616**
Total Conservation	1,788	1,865	2,278	2,241	2,231	2,622	2,271	2,277	2,511	2,151	2,068	2,102	**26,405**
Total Capacity	2,676	2,676	2,582	2,582	3,148	6,641	5,596	7,000	6,591	7,014	6,822	6,911	**60,239**
Total Environmental	11,924	12,345	13,283	11,958	12,382	12,851	12,335	12,600	12,532	12,117	12,172	12,813	**149,312**
Total Retail Revenues	**104,010**	**89,421**	**92,438**	**90,957**	**109,101**	**124,595**	**130,646**	**131,304**	**118,636**	**104,549**	**94,251**	**103,494**	**1,293,402**

Florida Public Service Commission
Docket No. 130140-EI
GULF POWER COMPANY
Witness: Susan D. Ritenour
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GULF POWER COMPANY
INCOME STATEMENT
For the Twelve Months Ended December 31, 2014
($000)

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	12 MONTHS ENDED DEC 2014
Sales for Resale - Territorial													
Total Sales For Resale - Territorial	2,790	2,498	2,471	2,439	2,770	2,962	3,137	3,163	2,889	2,630	2,531	2,797	33,077
Total Territorial Revenues	106,800	91,919	94,909	93,396	111,871	127,557	133,783	134,467	121,525	107,179	96,782	106,291	1,326,479
Non-Territorial Sales													
Total Assoc. Co. Revenues	7,282	5,838	5,378	3,774	2,721	5,723	10,215	12,726	8,014	4,180	8,051	6,459	**80,361**
Total Non-Assoc Co. Revenues	8,583	8,193	8,521	8,371	8,628	8,552	8,712	8,760	8,572	8,700	4,594	6,248	**96,434**
Total Non-Territorial Revenues	15,865	14,031	13,899	12,145	11,349	14,275	18,927	21,486	16,586	12,880	12,645	12,707	176,795
Other Operating Revenue	6,116	5,687	5,236	5,127	5,335	6,211	6,518	6,329	6,232	5,660	5,255	5,465	**69,171**
Total Electric Revenues	128,781	111,637	114,044	110,668	128,555	148,043	159,228	162,282	144,343	125,719	114,682	124,463	1,572,445
ELECTRIC O&M:													
Stesm Power Generation Fuel Cost													
Coal	27,327	17,916	20,822	22,722	23,247	28,310	32,563	36,345	27,456	25,261	17,357	19,434	**298,760**
Gas	289	245	200	237	278	238	280	281	239	283	286	249	**3,105**
Oil	160	128	143	118	157	153	156	156	152	155	107	88	**1,673**
Total Steam Fuel Cost	27,776	18,289	21,165	23,077	23,682	28,701	32,999	36,782	27,847	25,699	17,750	19,771	303,538
Fuel Handling	528	524	557	522	627	526	504	531	527	631	537	530	**6,544**
Steam O&M	7,980	13,067	11,763	10,026	9,513	8,945	8,142	8,617	8,964	12,308	10,648	10,896	**120,869**
Emissions	73	20	40	37	57	62	86	83	63	50	54	45	**670**
Total Steam Power Generation	36,357	31,900	33,525	33,662	33,879	38,234	41,731	46,013	37,401	38,688	28,989	31,242	431,621
Other Power Generation													
Fuel Cost: Gas & Oil	25,408	24,323	21,495	20,113	22,530	29,253	32,574	32,503	29,513	21,261	25,017	26,251	**310,241**
Other Pwr Generation Fuel Cost	25,408	24,323	21,495	20,113	22,530	29,253	32,574	32,503	29,513	21,261	25,017	26,251	**310,241**
Other Power Gen O&M	670	725	908	1,766	1,083	781	787	783	769	821	1,763	754	**11,610**
Total Other Power Generation	26,078	25,048	22,403	21,879	23,613	30,034	33,361	33,286	30,282	22,082	26,780	27,005	321,851
Purchased Power													
Total So. Pool Purchases	1,293	1,206	2,786	1,710	7,565	2,223	1,593	1,126	827	2,849	637	842	**24,657**
Non Associated Purchases	2,680	2,476	2,117	1,939	2,633	7,400	7,586	7,594	7,460	6,804	7,228	7,445	**63,362**
Total Purchased Power	3,973	3,682	4,903	3,649	10,198	9,623	9,179	8,720	8,287	9,653	7,865	8,287	88,019
Other Power Supply Expense	262	327	371	328	461	316	292	319	339	451	336	324	**4,126**
Total Other Power Supply Expenses	262	327	371	328	461	316	292	319	339	451	336	324	4,126
Total Power Production Expense	66,670	60,957	61,202	59,518	68,151	78,207	84,563	88,338	76,309	70,874	63,970	66,858	845,617
Total Prod Non-Fuel O&M	9,440	14,643	13,599	12,642	11,684	10,568	9,725	10,250	10,599	14,211	13,284	12,504	143,149

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GULF POWER COMPANY
Witness: Susan D. Ritenour
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GULF POWER COMPANY
INCOME STATEMENT
For the Twelve Months Ended December 31, 2014
($000)

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	12 MONTHS ENDED DEC 2014
Transmission O&M	2,259	2,393	2,483	2,520	2,603	2,188	2,152	2,250	2,186	2,298	2,073	1,981	**27,386**
Distribution O&M	4,264	3,609	3,868	3,857	3,482	4,075	3,768	3,750	3,889	3,828	3,588	3,760	**45,738**
Cust Accts, Serv, and Sales	5,586	4,859	4,960	5,269	5,867	5,907	5,378	5,280	5,606	5,297	5,576	6,258	**65,843**
Admin & General Expense	7,003	6,935	7,806	7,209	7,544	7,380	7,214	7,139	7,505	8,159	7,432	7,670	**88,996**
Total Non-Production O&M	**19,112**	**17,796**	**19,117**	**18,855**	**19,496**	**19,550**	**18,512**	**18,419**	**19,186**	**19,582**	**18,669**	**19,669**	**227,963**
Total Non-Fuel O&M	**28,552**	**32,439**	**32,716**	**31,497**	**31,180**	**30,118**	**28,237**	**28,669**	**29,785**	**33,793**	**31,953**	**32,173**	**371,112**
Total O&M	**85,782**	**78,753**	**80,319**	**78,373**	**87,647**	**97,757**	**103,075**	**106,757**	**95,495**	**90,456**	**82,639**	**86,527**	**1,073,580**
Depreciation Expense	12,328	12,342	12,367	12,402	12,426	12,447	12,479	12,498	12,517	12,536	12,553	12,574	**149,469**
Amort ITC	(102)	(102)	(102)	(102)	(102)	(102)	(102)	(102)	(102)	(102)	(102)	(102)	**(1,224)**
Amort of Property	595	591	570	570	570	570	570	570	570	570	570	568	**6,884**
Electric Income Taxes	6,208	2,610	3,063	2,439	5,672	8,757	10,760	10,468	7,932	2,830	2,185	4,244	**67,168**
Taxes Other	9,464	8,794	8,405	8,272	8,492	9,886	10,487	10,631	10,553	9,758	8,283	8,748	**111,773**
Total Depr, Amort & Taxes	**28,493**	**24,235**	**24,303**	**23,581**	**27,058**	**31,558**	**34,194**	**34,065**	**31,470**	**25,592**	**23,489**	**26,032**	**334,070**
Total Utility Operating Income	**14,506**	**8,649**	**9,422**	**8,714**	**13,850**	**18,728**	**21,959**	**21,460**	**17,378**	**9,671**	**8,554**	**11,904**	**164,795**
Other Income & Deductions													
AFUDC - Equity	734	794	854	921	976	1,020	1,065	1,110	1,159	1,220	1,290	1,324	**12,467**
Earnings on Temporary Cash	0	0	0	0	0	0	0	0	0	0	0	0	**0**
Other Income	81	82	81	80	79	77	73	73	78	81	81	83	**949**
Other Income Deductions	288	399	400	336	309	334	297	299	362	413	338	364	**4,139**
Taxes Other Than Income Taxes	0	0	0	0	0	0	0	0	0	0	0	0	**0**
Income Taxes	(54)	(96)	(97)	(73)	(63)	(74)	(61)	(61)	(84)	(102)	(74)	(82)	**(921)**
Total Other Income	**581**	**573**	**632**	**738**	**809**	**837**	**902**	**945**	**959**	**990**	**1,107**	**1,125**	**10,198**
Income Before Interest	**15,087**	**9,222**	**10,054**	**9,452**	**14,659**	**19,565**	**22,861**	**22,405**	**18,337**	**10,661**	**9,661**	**13,029**	**174,993**
Interest Charges													
Interest On Long-Term Debt	4,771	4,698	4,771	5,091	5,115	5,091	5,130	5,130	5,105	5,556	5,531	5,553	**61,542**
Interest on Short-Term Debt	31	5	20	22	11	26	51	40	48	48	23	91	**416**
Amort DD&P Gains/Losses	202	202	202	202	202	202	202	202	202	196	196	190	**2,400**
Other Interest Expense	67	67	68	68	68	68	68	68	68	68	68	68	**814**
AFUDC - Debt	(390)	(421)	(453)	(489)	(518)	(541)	(565)	(589)	(615)	(647)	(684)	(703)	**(6,615)**
Total Interest	**4,681**	**4,551**	**4,608**	**4,894**	**4,878**	**4,846**	**4,886**	**4,851**	**4,808**	**5,221**	**5,134**	**5,199**	**58,557**
Income Before Dividends	**10,406**	**4,671**	**5,446**	**4,558**	**9,781**	**14,719**	**17,975**	**17,554**	**13,529**	**5,440**	**4,527**	**7,830**	**116,436**
Dividends on Preferred Stock	740	740	740	740	740	740	740	740	740	740	740	740	**8,880**
Net Income	**9,666**	**3,931**	**4,706**	**3,818**	**9,041**	**13,979**	**17,235**	**16,814**	**12,789**	**4,700**	**3,787**	**7,090**	**107,556**

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GULF POWER COMPANY
Witness: Susan D. Ritenour
Exhibit No. _____ (SDR-1)
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GULF POWER COMPANY
UTILITY PLANT BALANCES
For the Period Ended December 2013 through December 2014
($000)

	2013 DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	2014 DEC
CAPITAL SUPPLEMENTAL SCHEDULE													
Non Depreciable:													
Beginning Balance	27,950	27,950	27,950	27,950	27,950	27,950	27,973	27,973	27,973	27,973	27,973	27,997	27,997
Placed in Service	0	0	0	0	0	23	0	0	0	0	23	0	0
Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-
Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	-
Balance End of Period	27,950	27,950	27,950	27,950	27,950	27,973	27,973	27,973	27,973	27,973	27,997	27,997	27,997
Depreciable:													
Beginning Balance	4,352,806	4,398,768	4,401,519	4,409,353	4,421,553	4,429,506	4,436,794	4,448,179	4,456,118	4,462,516	4,469,668	4,476,030	4,484,028
Placed in Service	49,554	5,221	11,183	14,524	9,579	8,168	12,357	9,236	7,529	8,376	7,467	9,227	111,543
Retirements	3,591	2,470	3,349	2,325	1,625	881	972	1,297	1,130	1,223	1,106	1,229	3,864
Balance End of Period	4,398,768	4,401,519	4,409,353	4,421,553	4,429,506	4,436,794	4,448,179	4,456,118	4,462,516	4,469,668	4,476,030	4,484,028	4,591,706
Plant Held for Future Use:													
Beginning Balance	18,456	18,456	18,456	18,456	18,456	18,456	18,456	18,456	18,456	18,456	18,456	18,456	18,456
Adjustments & Transfers	-	-	-	-	-	-	-	-	-	-	-	-	-
Balance End of Period	18,456	18,456	18,456	18,456	18,456	18,456	18,456	18,456	18,456	18,456	18,456	18,456	18,456
Construction Work in Progress:													
Beginning Balance	265,144	242,066	275,495	305,098	335,324	366,405	390,879	412,222	436,360	461,902	492,381	529,773	568,889
Expenditures	26,475	38,650	40,786	44,750	40,659	32,666	33,701	33,373	33,071	38,854	44,883	48,343	48,087
Placed in Service	49,554	5,221	11,183	14,524	9,579	8,192	12,357	9,236	7,529	8,376	7,491	9,227	111,543
Balance End of Period	242,066	275,495	305,098	335,324	366,405	390,879	412,222	436,360	461,902	492,381	529,773	568,889	505,433
Plant Acquisition Adjustment:													
Beginning Balance	2,052	2,031	2,010	1,988	1,967	1,946	1,925	1,903	1,882	1,861	1,839	1,818	1,797
Adjustments & Transfers	(21)	(21)	(21)	(21)	(21)	(21)	(21)	(21)	(21)	(21)	(21)	(21)	(21)
Balance End of Period	2,031	2,010	1,988	1,967	1,946	1,925	1,903	1,882	1,861	1,839	1,818	1,797	1,776
Total Utility Plant:													
Beginning Balance	4,666,408	4,689,271	4,725,430	4,762,846	4,805,250	4,844,262	4,876,026	4,908,734	4,940,789	4,972,708	5,010,318	5,054,074	5,101,166
Expenditures	26,475	38,650	40,786	44,750	40,659	32,666	33,701	33,373	33,071	38,854	44,883	48,343	48,087
Retirements	3,591	2,470	3,349	2,325	1,625	881	972	1,297	1,130	1,223	1,106	1,229	3,864
Adjustments & Transfers	(21)	(21)	(21)	(21)	(21)	(21)	(21)	(21)	(21)	(21)	(21)	(21)	(21)
Balance End of Period	4,689,271	4,725,430	4,762,846	4,805,250	4,844,262	4,876,026	4,908,734	4,940,789	4,972,708	5,010,318	5,054,074	5,101,166	5,145,368
Accumulated Provision:													
Beginning Balance	1,476,365	1,485,261	1,495,382	1,503,891	1,514,150	1,525,321	1,537,277	1,549,055	1,560,514	1,572,245	1,583,764	1,595,333	1,606,459
Provision for Depreciation	12,408	12,537	12,551	12,576	12,612	12,636	12,657	12,689	12,710	12,731	12,752	12,772	12,794
Provision for Amortization	509	512	510	487	487	487	487	487	487	487	487	487	485
Retirements	3,591	2,470	3,349	2,325	1,625	881	972	1,297	1,130	1,223	1,106	1,229	3,864
Removal	496	542	1,289	567	382	344	492	519	453	586	667	1,008	474
Salvage	(67)	(83)	(86)	(87)	(79)	(59)	(97)	(100)	(118)	(112)	(103)	(105)	(70)
Adjustments & Transfers	-	-	-	-	-	-	-	-	-	-	-	-	-
Balance End of Period	1,485,261	1,495,382	1,503,891	1,514,150	1,525,321	1,537,277	1,549,055	1,560,514	1,572,245	1,583,764	1,595,333	1,606,459	1,615,470

Totals may not add due to rounding.

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Gulf Power Company
13-Month Average Rate Base
for the Period Ended December 31, 2014
(Thousands of Dollars)

Description	(1) Total System	(2) Regulatory Adjustments *	Adj #	(3) UPS Amounts	(4) Total System Adjusted	(5) Jurisdictional Factor **	(6) Jurisdictional Adjusted Rate Base
Plant-in-Service	4,480,719	(1,089,643)	(1-5)	(391,179)	2,999,897	0.9814230	2,944,168
Accumulated Depreciation and Amortization	1,549,548	(151,504)	(6-11)	(129,995)	1,268,049	0.9804976	1,243,319
Net Plant-in-Service	2,931,171	(938,139)		(261,184)	1,731,848	0.9821006	1,700,849
Plant Held for Future Use	18,456	(13,021)	(12)		5,435	0.9707452	5,276
Construction Work-in-Progress	409,402	(375,555)	(13-14)	(6,557)	27,290	0.9767680	26,656
Plant Acquisition Adjustment	1,903			(1,903)	-		
Net Utility Plant	3,360,932	(1,326,715)		(269,644)	1,764,573	0.9819832	1,732,781
Working Capital Allowance (Per Schedule 11)	157,498	6,122	(15)	(8,424)	155,196	0.9737364	151,120
Total Rate Base	3,518,430	(1,320,593)		(278,068)	1,919,769		1,883,901

* See Page 2
** See O'Sheasy Exhibit MTO-2

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Gulf Power Company
Schedule of Adjustments to Test Year 13-Month Average Rate Base for the Period Ended December 31, 2014 (Thousands of Dollars)

Description of Adjustments	(1) Total System Adjustment	(2) Jurisdictional Allocation Factor	(3) Total Jurisdictional Adjustment	(4) Jurisdictional Revenue Effect
(1) Plant-in-Service - Environmental Cost Recovery Clause	(1,060,314)	0.9702233	(1,028,741)	(96,747)
(2) Plant-in-Service - Conservation Cost Recovery Clause	(14,764)	1.0000000	(14,764)	(1,388)
(3) Plant-in-Service - Asset Retirement Obligations	(8,037)	0.9706671	(7,801)	(734)
(4) Plant-in-Service - Perdido Unit 3	(4,460)	0.9701832	(4,327)	(407)
(5) Plant-in-Service - Distribution New Business	(2,068)	0.9999470	(2,068)	(194)
(6) Accumulated Depreciation - Environmental Cost Recovery Clause	166,377	0.9702219	161,423	15,181
(7) Accumulated Depreciation - Conservation Cost Recovery Clause	(3,586)	1.0000000	(3,586)	(337)
(8) Accumulated Depreciation - Asset Retirement Obligations	(11,479)	0.9699795	(11,134)	(1,047)
(9) Accumulated Depreciation - Perdido Unit 3	127	0.9701838	123	12
(10) Accumulated Depreciation - Distribution New Business	22	0.9999456	22	2
(11) Accumulated Depreciation - 2013 Depr & Dismantlement Studies	43	Various	62	6
(12) Plant Held for Future Use - North Escambia	(13,021)	0.9702652	(12,634)	(1,188)
(13) CWIP - Interest Bearing	(312,857)	0.9767680	(305,589)	(28,739)
(14) CWIP - Non Interest Bearing - Environmental Cost Recovery Clause	(62,698)	0.9701895	(60,829)	(5,721)
(15) Working Capital Adjustments (See Schedule 11)	6,122	0.9737364	5,961	561
Total Adjustments	(1,320,593)		(1,283,882)	(120,740)

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Gulf Power Company
13-Month Average Working Capital
For the Period Ended December 31, 2014
(Thousands of Dollars)

Description	Other Prop & Investments	Current Assets	Deferred Debits	Operating Reserves	Current Liabilities	Deferred Credits	Total
Total Company Working Capital Less Non - Utility	101,252	345,902	468,604	(281,257)	(199,833)	(277,170)	157,498
Less Regulatory Adjustments for:							
Items Earning or Paying a Return							
Funded Property Insurance Reserve	22,726			(22,726)			-
Funded Portion of Def Comp Assets	2,598					(2,598)	-
Loans To Employees & Retirees		38					38
Interest & Dividends Receivable		25					25
Recovery Clause Items							
Energy Select Inventory (ECCR)		2,466					2,466
Environmental Allowances (ECRC)		6,783	624				7,407
Environmental Allowance & Deferred Gain (ECRC)						(204)	(204)
Other Regulatory Items							
Minimum Pension Funding (FAS 158)	2,455		154,167	(154,167)		(2,455)	-
PPA Deferred Assets and Liabilities			191,514			(191,514)	-
Hedge Assets and Liabilities			27,112		(27,112)		-
Increase in Property Damage Reserve Accrual				2,750			2,750
Asset Retirement Obligation (FAS 143)			5,382	(16,055)		(14,326)	(24,999)
North Escambia Site Costs			5,149				5,149
Unamort. 2011 Rate Case Expenses			1,246				1,246
Total Regulatory Adjustments	27,779	9,312	385,194	(190,198)	(27,112)	(211,097)	(6,122)
TOTAL ADJUSTED WORKING CAPITAL	73,473	336,590	83,410	(91,059)	(172,721)	(66,073)	163,620
Less: UPS Working Capital	0	13,761	1,881	(1,471)	(4,157)	(1,590)	8,424
TOTAL SYSTEM ADJUSTED ON SCHEDULE 10	73,473	322,829	81,529	(89,588)	(168,564)	(64,483)	155,196

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Gulf Power Company
Net Operating Income
For the Twelve Months Ended December 31, 2014
(Thousands of Dollars)

Description	(1) Total System	(2) Regulatory Adjustments *	Adjust No.	(3) UPS Amounts	(4) System Adjusted	(5) Jurisdictional Factor **	(6) Jurisdictional Adjusted NOI
Operating Revenues:							
Sales of Electricity	1,503,274	(926,938)	(1,2,3,4,6)	(58,261)	518,075	0.9759591	505,620
Other Operating Revenues	69,171	(42,247)	(5)	-	26,924	0.8554078	23,031
Total Operating Revenues	1,572,445	(969,185)		(58,261)	544,999	0.9700036	528,651
Operating Expenses:							
Operation & Maintenance Expense							
Recoverable Fuel	650,274	(650,274)	(7-10)				
Recoverable Capacity	65,247	(65,247)	(11-12)				
Recoverable Conservation	23,520	(23,520)	(13)				
Recoverable Environmental	29,077	(29,077)	(14)				
Other Operation & Maintenance	305,462	3,146	(15-24, 26)	(12,692)	295,916	0.9806803	290,199
Depreciation & Amortization	156,353	(41,951)	(25, 27-30)	(7,975)	106,427	0.9819407	104,505
Amortization of Investment Tax Credit	(1,224)			330	(894)	0.9821029	(878)
Taxes Other Than Income Taxes	111,773	(78,032)	(31-37)	(1,119)	32,622	0.9783888	31,917
Income Taxes:							
Federal	46,880	(21,921)	(38-39)	(8,526)	16,433	0.9038265	14,852
State	1,934	(3,646)	(38-39)	(354)	(2,066)	0.9038265	(1,867)
Deferred Income Taxes - Net							
Federal	10,764			(1,958)	8,806	0.9038265	7,959
State	7,590			(1,389)	6,201	0.9038265	5,605
Total Operating Expenses	1,407,650	(910,522)		(33,683)	463,445		452,292
Net Operating Income	164,795	(58,663)		(24,578)	81,554		76,359

* See Pages 2 and 3
** See O'Sheasy Exhibit MTO-2

Gulf Power Company
Schedule of Adjustments to NOI
For the Twelve Months Ended December 31, 2014
Revenues
(Thousands of Dollars)

		(1)	(2)	(3)	(4)	(5)
Description of Adjustment	Schedule Reference	System Amount	Allocation Factor	Jurisdictional Amount	NOI Effect	Revenue Effect
(1) Fuel Clause Revenues	Schedule 13	(651,123)	Direct	(597,603)	(367,078)	599,795
(2) PPCC Recovery Clause Revenues	Schedule 14	(63,154)	Direct	(63,054)	(38,731)	63,285
(3) ECCR Clause Revenues	Schedule 15	(26,405)	Direct	(26,405)	(16,219)	26,501
(4) ECRC Clause Revenues	Schedule 16	(153,917)	Direct	(149,312)	(91,715)	149,860
(5) Franchise Fee Revenues		(42,247)	1.0000000	(42,247)	(25,950)	42,402
(6) Gross Receipts Tax Revenues		(32,339)	1.0000000	(32,339)	(19,864)	32,457
Total Revenue Adjustments		(969,185)		(910,960)	(559,557)	914,300

Abbreviations:
PPCC - Purchased Power Capacity Cost
ECCR - Energy Conservation Cost Recovery
ECRC - Environmental Cost Recovery Clause

Gulf Power Company
Schedule of Adjustments to NOI
For the Twelve Months Ended December 31, 2014
Expenses
(Thousands of Dollars)

Adj No.	Description of Adjustment	Schedule Reference	(1) System Amount	(2) Allocation Factor	(3) Jurisdictional Amount	(4) NOI Effect	(5) Revenue Effect
(7)	Total Fuel Expense	Sch. 13	(613,779)	0.9206164	(565,055)	347,085	(567,127)
(8)	Interchange Energy-Fuel Portion	Sch. 13	(35,992)	0.8805846	(31,694)	19,468	(31,810)
(9)	Purchase Power Transm Recov Through Fuel	Sch. 13	(403)	0.9702233	(391)	240	(392)
(10)	Peabody Litigation Fees	Sch. 13	(100)	0.9700000	(97)	60	(98)
(11)	PPCC Production Expenses Included in O&M	Sch. 14	(52,026)	0.9657346	(50,243)	30,862	(50,428)
(12)	PPCC Transmission Expenses Included in O&M	Sch. 14	(13,221)	0.9657346	(12,768)	7,843	(12,815)
(13)	ECCR Expense in O&M	Sch. 15	(23,520)	1.0000000	(23,520)	14,447	(23,606)
(14)	ECRC Expense in O&M	Sch. 16	(29,077)	0.9698043	(28,199)	17,321	(28,302)
(15)	Marketing Support Activities		(156)	1.0000000	(156)	96	(157)
(16)	Wholesale Sales Exp		(255)	1.0000000	(255)	157	(257)
(17)	Institutional Advertising		(30)	0.9835526	(30)	18	(29)
(18)	Economic Development Expenses		(63)	0.9997389	(63)	39	(64)
(19)	Management Financial Planning		(41)	0.9835526	(40)	25	(41)
(20)	Increase in Property Damage Reserve Accrual		5,500	0.9845096	5,415	(3,326)	5,435
(21)	Tallahassee Liaison Expenses - O&M		(306)	0.9835526	(301)	185	(302)
(22)	Amortization of Rate Case Expenses	Sch. 17	930	1.0000000	930	(571)	933
(23)	Hiring Lag Adjustment to O&M		(558)	0.9836779	(549)	337	(551)
(24)	Perdido Unit 3 Adjustment - Production O&M		(400)	0.9705189	(388)	238	(389)
(25)	Perdido Unit 3 Adjustment - Depreciation		(254)	0.9701809	(246)	151	(247)
(26)	Scholz O&M		(1,475)	0.9705159	(1,432)	880	(1,438)
(27)	ECRC Expense in Depreciation	Sch. 16	(40,922)	0.9705293	(39,716)	24,396	(39,862)
(28)	ECCR Expense in Depreciation	Sch. 15	(411)	1.0000000	(411)	252	(412)
(29)	Distribution New Business Depreciation		(67)	0.9999468	(67)	41	(67)
(30)	Change in Depreciation & Dismantlement: 2013 Studies		(297)	Various	(332)	204	(333)
(31)	Perdido Unit 3 Adjustment - Property Tax		(58)	0.9701749	(56)	34	(56)
(32)	ECCR Expense in Other Taxes	Sch. 15	(691)	1.0000000	(691)	424	(693)
(33)	Franchise Fee Expense		(41,160)	1.0000000	(41,160)	25,283	(41,312)
(34)	Tallahassee Liaison Expenses - Payroll Taxes		(20)	0.9830180	(20)	12	(20)
(35)	ECRC Expense in Property Taxes	Sch. 16	(2,153)	0.9702740	(2,089)	1,283	(2,096)
(36)	Gross Receipts Tax		(33,371)	1.0000000	(33,371)	20,498	(33,493)
(37)	FPSC Assessment Fee	Sch. 18	(579)	1.0000000	(579)	356	(582)
	Subtotal		(884,955)		(827,574)	508,338	(830,611)
(38)	Tax Effect of Adjustments - Federal	Sch. 19	(27,859)	n/a	(27,580)	-	-
	- State		(4,633)	n/a	(4,586)	-	-
(39)	Tax Effect of Interest Synchronization	Sch. 20					
	- Federal		5,938	0.9841698	5,844	(5,844)	9,549
	- State		987	0.9848024	972	(972)	1,588
	Total Expense Adjustments		(910,522)		(852,924)	501,522	(819,474)

Abbreviations:
PPCC - Purchased Power Capacity Cost
ECCR - Energy Conservation Cost Recovery
ECRC - Environmental Cost Recovery Clause

Gulf Power Company
Fuel Revenues and Expenses
For the Twelve Months Ended December 31, 2014
(Thousands of Dollars)

		System Amount	Jurisdictional Amount
Fuel Revenues:			
Retail Fuel Clause Revenues		526,616	526,616
Territorial Wholesale Fuel Revenues		16,232	-
Non-Territorial Fuel Revenues			
Associated Companies Sales		70,254	67,956
Unit Power Sales		34,899	-
Opportunity Sales		3,122	3,031
Total Fuel Revenues	Adj. 1	651,123	597,603
Fuel Expenses:			
Fuel Expense per the Income Statement	Adj. 7	613,779	565,055
Interchange Energy-Fuel Portion	Adj. 8	35,992	31,694
Purchase Power Transm Recov Through Fuel	Adj. 9	403	391
Peabody Litigation Fees	Adj. 10	100	97
Total Fuel Expenses		650,274	597,237
Revenue Taxes @ 0.072% (All Retail)	Adj. 37	379	379
Total Fuel-Related Costs		650,653	597,616
Net Over (Under) Recovery of Fuel Expenses		470	(13)

Gulf Power Company
Purchase Power Capacity Cost (PPCC) Recovery Clause Revenues and Expenses
For the Twelve Months Ended December 31, 2014
(Thousands of Dollars)

		System Amount	Jurisdictional Amount
PPCC Revenues:			
Retail PPCC Revenues		60,239	60,239
Associated Companies Production Capacity Sales		2,584	2,495
Transmission Revenues Credited to Retail Customers in Capacity Clause		331	320
Total PPCC Recovery Clause Revenues	Adj. 2	63,154	63,054
PPCC Recovery Clause Expenses:			
PPCC Production Expense Included in O&M	Adj. 11	52,026	50,243
PPCC Transmission Expense Included in O&M	Adj. 12	13,221	12,768
Revenue Taxes @ 0.072% (All Retail)	Adj. 37	43	43
Total PPCC Recovery Clause Expenses		65,290	63,054
Net Over (Under) Recovery of PPCC Recovery Clause Expenses		(2,136)	-

Gulf Power Company
Energy Conservation Cost Recovery (ECCR) Clause Revenues and Expenses
For the Twelve Months Ended December 31, 2014
(Thousands of Dollars)

		System Amount	Jurisdictional Amount
ECCR Clause Revenues	Adj. 3	26,405	26,405
ECCR Clause Expenses:			
ECCR O&M Expense			
Customer Service & Info.		21,931	21,931
Administrative & General		1,589	1,589
Total ECCR O&M Expense	Adj. 13	23,520	23,520
ECCR Clause Depreciation Expense	Adj. 28	411	411
ECCR Clause Expenses in Other Taxes			
Property Taxes		322	322
Payroll Taxes		369	369
Total ECCR Clause Expenses in Other Taxes	Adj. 32	691	691
Revenue Taxes @ 0.072%	Adj. 37	19	19
Carrying Costs of ECCR Clause Investment		1,764	1,764
Total ECCR Clause Expenses		26,405	26,405
Net Over (Under) Recovery of ECCR Clause Expenses		-	-

Gulf Power Company
Environmental Cost Recovery Clause (ECRC) Revenues and Expenses
For the Twelve Months Ended December 31, 2014
(Thousands of Dollars)

		System Amount	Jurisdictional Amount
ECRC Revenues			
Retail Environmental Clause Revenues		149,312	149,312
Wholesale Environmental Clause Revenues		4,605	-
Total Environmental Clause Revenues	Adj. 4	153,917	149,312
ECRC Expenses			
ECRC Expense in O&M			
Production O&M		24,723	23,991
Transmission O&M		9	9
Distribution O&M		3,576	3,453
Admin. & General O&M		769	746
Total ECRC Expense in O&M	Adj. 14	29,077	28,199
Depreciation	Adj. 27	40,922	39,716
Taxes Other Than Income Taxes			
Revenue Taxes (All Retail)	Adj. 37	108	108
Property and Payroll Taxes	Adj. 35	2,153	2,089
Carrying Costs on ECRC Investment		81,606	79,195
Total ECRC Expenses		153,866	149,307
Net Over (Under) Recovery of ECRC Expenses		51	5

Gulf Power Company

Calculation of 2013 Rate Case Amortization NOI Adjustment
For the Twelve Months Ended December 31, 2014
(Thousands of Dollars)

		Amount
2013 Rate Case Expense Estimate		4,922
Projected Balance of Unamortized 2011 Rate Case Expenses at 12/31/2013		1,596
Total		6,518
Amortization Period		4 years
Annual Amortization		1,630
Amortization of 2011 Rate Case Expenses Included in 2014 O&M Budget		700
2014 NOI Adjustment for Rate Case Expenses	Adj. 22	**930**

Gulf Power Company
FPSC Assessment Fees
For the Twelve Months Ended December 31, 2014
(Thousands of Dollars)

		Retail Revenue Amount	FPSC Assessment Fee at .072%
Revenue Adjustments:			
Retail Fuel Clause Revenues (Sch. 13)	Adj. 1	526,616	379
PPCC Recovery Clause Revenues (Sch. 14)	Adj. 2	60,239	43
ECCR Clause Revenues (Sch. 15)	Adj. 3	26,405	19
ECRC Revenues (Sch. 16)	Adj. 4	149,312	108
Franchise Fee Revenues (Sch. 12, p. 2 of 3)	Adj. 5	42,247	30
Total FPSC Assessment Fee	Adj. 37		579

Gulf Power Company
Income Taxes Adjustments
For the Twelve Months Ended December 31, 2014
(Thousands of Dollars)

		System Amount
Adjustment Due to Revenue and Expense Adjustments		
Revenue Adjustments (Schedule 12, p.2 of 3)	Adjs. 1 - 6	(969,185)
Expense Adjustments (Schedule 12, p. 3 of 3)	Adjs. 7 - 37	(884,955)
Net Decrease to Taxable Income		(84,230)
Federal Income Tax @ 33.075%	Adj. 38	(27,859)
State Income Tax @ 5.5%	Adj. 38	(4,633)
Total	Adj. 38	(32,492)

Gulf Power Company
Interest Synchronization Adjustment
For the Twelve Months Ended December 31, 2014
(Thousands of Dollars)

Interest Synchronization

	Amount	Cost Rate	Expense
Total Company			
Long Term Debt	801,987	4.96%	39,779
Short-Term Debt	32,323	0.82%	265
Customer Deposits	22,117	2.30%	509
ITC-Debt Component	1,014	4.96%	50
Total Synchronized Interest			40,603
Total Company Interest Expense			58,557
Difference			(17,954)
Federal Income Tax @ 33.075%		Adj. 39	5,938
State Income Tax @ 5.5%		Adj. 39	987
Total			6,925
Jurisdictional			
Long Term Debt	685,025	4.96%	33,977
Short-Term Debt	27,615	0.82%	226
Customer Deposits	20,943	2.30%	482
ITC-Debt Component	839	4.96%	42
Total Synchronized Interest			34,727
Total Company Interest Expense		58,557	
Less: Unit Power Sales Interest		5,163	
		53,394	
Jurisdictional Factor		0.9813165	52,396
Difference			(17,669)
Federal Income Tax @ 33.075%		Adj. 39	5,844
State Income Tax @ 5.5%		Adj. 39	972
Total			6,816

Gulf Power Company
13-Month Average Jurisdictional Cost of Capital
For the Period Ended December 31, 2014
(Thousands of Dollars)

Item Description	(A) Jurisdictional Capital Structure (000's)	(B) Ratio %	(C) Cost Rate %	(D) Weighted Cost Rate %
Long-Term Debt	685,025	36.36	4.96	1.80
Short-Term Debt	27,615	1.47	0.82	0.01
Preference Stock	79,085	4.20	6.00	0.25
Common Equity	715,221	37.96	11.50	4.37
Customer Deposits	20,943	1.11	2.30	0.03
Deferred Taxes	379,918	20.17	0.00	0.00
FASB 109 Deferred Taxes	(25,718)	-1.37	0.00	0.00
Investment Credit - Weighted Cost	1,812	0.10	8.18	0.01
Total	1,883,901	100.00		6.47

GULF POWER COMPANY
13-Month Average Capital Structure
December 31, 2014
(Thousands of Dollars)

Description	(1) Total Company	(2) Less: Common Dividends Declared	(3) Less: Unamort. Prem., Disc., Issuance Exp. & Loss On Reacquired Debt	(4) Less: Non-Utility Adjs.	(5) Less: Unamort. Loss or Gain on Hedge	(6) Subtotal	(7) Less: Unit Power Sales Investment	(8) Subtotal	(9) Ratio	(10) Other Rate Base Adjs.	(11) Total Adjusted Capital Structure Net of UPS	(12) Juris. Factor	(13) Juris. Capital Structure
Long-Term Debt	1,312,417		29,059		1,502	1,281,856	103,347	1,178,509	0.36369671	480,295	698,214	0.9811104	685,025
Short-Term Debt	51,663					51,663	4,154	47,509	0.01466163	19,362	28,147	0.9811104	27,615
Preference Stock	147,998					147,998	11,941	136,057	0.04198821	55,449	80,608	0.9811104	79,085
Common Equity	1,331,975	(18,548)		13,029	(923)	1,338,417	107,959	1,230,458	0.37972856	501,467	728,991	0.9811104	715,221
Customer Deposits	35,350					35,350		35,350	0.01090927	14,407	20,943	1.0000000	20,943
Deferred Taxes	706,974				(579)	707,553	53,944	653,609	0.20170864	266,376	387,233	0.9811104	379,918
FASB 109 Deferred Taxes	(47,899)					(47,899)	(3,652)	(44,247)	(0.01365496)	(18,033)	(26,214)	0.9811104	(25,718)
Investment Credit - Weighted Costs	3,492					3,492	375	3,117	0.00096193	1,270	1,847	0.9811104	1,812
Total	3,541,970	(18,548)	29,059	13,029	-	3,518,430	278,068	3,240,362	1.00000000	1,320,593	1,919,769		1,883,901

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GULF POWER COMPANY
13-Month Average Cost of Long-Term Debt
at December 31, 2014

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
Issue	Issue Date	Maturity Date	Principal	Unamortized Prem.,Disc., Issuing Exp. & Loss on Reacquired Debt	Unamortized Loss/(Gain) on Hedge	Net (4) - (5) - (6)	Amortization Prem.,Disc., Issuing Exp. & Loss on Reacquired Debt	Amort Loss/(Gain) on Hedge	Interest (1) x (4)	Annual Total Cost (8) + (9) + (10)
Senior Notes and Other Long-Term Debt										
5.75% Senior Note	5/18/2011	6/1/2051	125,000	3,812	0	121,188	101	0	7,188	7,289
3.10% Senior Note	5/18/2012	5/15/2022	100,000	730	0	99,270	92	0	3,100	3,192
4.75% Senior Note	6/1/2013	5/1/2043	55,000	0	0	55,000	0	0	2,613	2,613
4.90% Senior Note	9/22/2004	10/1/2014	57,692	20	0	57,672	71	0	2,827	2,898
5.10% Senior Note	9/17/2010	10/1/2040	125,000	1,116	0	123,884	43	0	6,375	6,418
5.25% Senior Note	7/22/2003	7/15/2033	30,000	992	0	29,008	52	0	1,575	1,627
5.65% Senior Note	8/30/2005	9/1/2035	60,000	692	0	59,308	33	0	3,390	3,423
5.85% Senior Note	4/1/2014	3/1/2044	48,462	0	0	48,462	0	0	2,835	2,835
6.25% Senior Note	10/1/2014	9/1/2044	32,308	0	0	32,308	0	0	2,019	2,019
4.75% Senior Note	4/13/2010	4/15/2020	175,000	772	(883)	175,111	134	(153)	8,313	8,294
5.30% Senior Note	12/6/2006	12/1/2016	110,000	239	1,312	108,449	99	540	5,830	6,469
5.90% Senior Note	6/12/2007	6/15/2017	85,000	237	(890)	85,653	80	(303)	5,015	4,792
Pollution Control Bonds										
4.725% PCB	11/20/2012	11/1/2042	13,000	676	0	12,324	7	0	614	621
5.25% PCB	9/26/2002	9/1/2037	42,000	1,355	0	40,645	58	0	2,205	2,263
5.625% PCB	10/9/2002	7/1/2022	37,000	514	0	36,486	64	0	2,081	2,145
6.0% PCB	4/15/2003	2/1/2026	29,075	863	0	28,212	74	0	1,745	1,819
VAR% PCB	7/1/1997	7/1/2022	3,930	17	0	3,913	2	0	34	36
VAR% PCB	3/31/2009	4/1/2039	65,400	1,091	0	64,309	44	0	573	617
1.55% PCB	4/15/2003	6/1/2023	32,550	671	0	31,879	75	0	505	580
1.35% PCB	3/31/2009	4/1/2039	65,000	519	0	64,481	21	0	878	899
4.275% PCB	6/3/2010	6/1/2049	21,000	356	0	20,644	14	0	898	912

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GULF POWER COMPANY
13-Month Average Cost of Long-Term Debt
at December 31, 2014

(1) Issue	(2) Issue Date	(3) Maturity Date	(4) Principal	(5) Unamortized Prem.,Disc., Issuing Exp. & Loss on Reacquired Debt	(6) Unamortized Loss/(Gain) on Hedge	(7) Net (4) - (5) - (6)	(8) Amortization Prem.,Disc., Issuing Exp. & Loss on Reacquired Debt	(9) Amort Loss/(Gain) on Hedge	(10) Interest (1) x (4)	(11) Annual Total Cost (8) + (9) + (10)
Reacquired Debt										
GULF - FMB, 10 1/8% SERIES DUE 2016	2/19/1986	2/1/2016	0	268	0	(268)	169	0	0	169
GULF - FMB, 6 7/8% SERIES DUE 2026	1/1/1996	1/1/2026	0	1133	0	(1,133)	98	0	0	98
GULF - FMB, 8 3/4% SERIES DUE 2021	12/4/1991	12/1/2021	0	1124	0	(1,124)	152	0	0	152
GULF - PCB, $39M Var Rate PCB Esc Cnty	7/1/1997	7/1/2022	0	348	0	(348)	43	0	0	43
GULF - PCB, 10 1/2% SERIES DUE 2014	12/1/1984	12/1/2014	0	31	0	(31)	67	0	0	67
GULF - PCB, 10% SERIES DUE 2013	8/1/1983	8/1/2013	0	0	0	0	0	0	0	0
GULF - PCB, 12 3/5% SERIES DUE 2012	8/1/1982	8/1/2012	0	0	0	0	0	0	0	0
GULF - PCB, 5 1/2% SERIES DUE 2026	2/1/1996	2/1/2026	0	214	0	(214)	0	0	0	0
GULF - PCB, 5.7% SERIES DUE 2023	11/1/1993	11/1/2023	0	100	0	(100)	18	0	0	18
GULF - PCB, 5.8% SERIES DUE 2023	6/1/1993	6/1/2023	0	226	0	(226)	11	0	0	11
GULF - PCB, 6 3/4% SERIES DUE 2022	3/1/1992	3/1/2022	0	154	0	(154)	25	0	0	25
GULF - PCB, 6.2% SERIES DUE 2023	4/1/1993	4/1/2023	0	131	0	(131)	20	0	0	20
GULF - PCB, 6.3% SERIES DUE 2024	8/15/1994	9/1/2024	0	199	0	(199)	15	0	0	15
GULF - PCB, 6.7% SR INSUR QRTLY DUE 2038	7/1/2008	7/1/2038	0	977	0	(977)	20	0	0	20
GULF - PCB, 7.125% SERIES DUE 2021	4/1/1991	4/1/2021	0	251	0	(251)	41	0	0	41
GULF - PCB, 8 1/4% SERIES DUE 2017	6/1/1987	6/1/2017	0	191	0	(191)	37	0	0	37
GULF - PCB, VAR RATE SERIES DUE 2024	9/1/1994	9/1/2024	0	89	0	(89)	65	0	0	65
GULF - SNR - 5.25%, 60M, 2033	7/22/2003	7/15/2033	0	994	0	(994)	9	0	0	9
GULF - SNR - 5.60%, 65M, 2033	3/26/2003	4/1/2033	0	1999	0	(1,999)	52	0	0	52
GULF - SNR - 5.875%, 35M, 2044	4/13/2004	4/1/2044	0	926	0	(926)	107	0	0	107
GULF - SNR, 5.75%, 40M, 2033	6/16/2003	9/15/2033	0	1380	0	(1,380)	31	0	0	31
GULF - SNR, 6.0% SR NOTE SERIES E DUE 2012	1/30/2002	1/30/2012	0	0	0	0	72	0	0	72
GULF - SNR, 6.10% SR INS SERIES DUE 2016	10/18/2001	9/30/2016	0	282	0	(282)	0	0	0	0
GULF - SNR, 7.50% SERIES DUE 2037	8/1/1997	6/30/2037	0	426	0	(426)	125	0	0	125
GULF - Trust, AMORT LOSS 7% CAPITAL TRUST II	1/20/1998	12/31/2037	0	926	0	(926)	19	0	0	19
GULF - Trust, Cap Trust 1 Due 2037 7.625	1/31/1997	12/31/2036	0	830	0	(830)	40	0	0	40
GULF - Trust, Capital Trust IV Due 11/30/2042	12/13/2002	11/30/2042	0	414	0	(414)	35	0	0	35
GULF - Trust, Capital Trust III	11/16/2001	9/30/2041	0	774	0	(774)	29	0	0	29
GULF - VAR % Bank Note	6/9/2008	7/1/2011	0	0	1,963	(1,963)	15	522	0	537
Total Long-Term Debt			1,312,417	29,059	1,502	1,281,856	2,379	606	60,613	63,598
Embedded Cost of Long-Term Debt										**4.96%**
Less: Adjustment for Unit Power Sales			103,347	0	0	103,347	0	0	5,127	5,127
Long-Term Debt net of UPS			1,209,070	29,059	1,502	1,178,509	2,379	606	55,486	58,471
Embedded Cost of Long-Term Debt net of UPS										**4.96%**

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GULF POWER COMPANY

13-Month Average Cost of Preference Stock

at December 31, 2014

Issue	(1) After-Tax Cost Rates	(2) Issue Date	(3) Call Provisions or Special Restrictions	(4) Principal Amount Sold	(5) Issue Expense	(6) Net Proceeds (4)-(5)	(7) Dividends Declared and Paid (1)x(4)	(8) Cost of Money (7) / (6)
Preference Stock								
6.00%	6.00%	11-15-05	Note 1	55,000	1,114	53,886	3,300	6.12%
6.45%	6.45%	10-19-07	Note 2	45,000	888	44,112	2,903	6.58%
5.36%	5.36%	4-01-13		50,000	-	50,000	2,680	5.36%
Total Preference Stock				150,000	2,002	147,998	8,883	6.00%
Less: Adjustment for Unit Power Sales				11,941		11,941	716	
Preference Stock net of UPS				138,059		136,057	8,167	6.00%

Note 1: The Company shall have the right to redeem Preference Stock, without premium, from time to time, on or after November 15, 2010, upon notice, at a redemption price equal to $100.00 per share plus accrued and unpaid dividends.

Note 2: The Company shall have the right to redeem the Preference Stock, from time to time, per the calculation outlined in the prospectus dated November 20, 2006.

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Gulf Power Company
FPSC Adjusted Achieved Rate of Return and Return on Common Equity
For the Test Year Ended 12/31/2014
(Thousands of Dollars)

	Schedule Reference	Amount
Jurisdictional Adjusted NOI Achieved	12	76,359
Divide by Jurisdictional Adjusted Rate Base	10	1,883,901
Achieved Rate of Return		4.05
Less: Retail Weighted Cost Rates (6.47% - 4.37%)	21	2.10
Return Available for Common Equity		1.95
Divide by Jurisdictional Adjusted Common Equity Ratio	21	37.96
Achieved Jurisdictional Return on Common Equity		5.14%

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Gulf Power Company
Calculation of Revenue Deficiency
For the Test Year Ended 12/31/2014
(Thousands of Dollars)

	Schedule Reference	Amount
Jurisdictional Adjusted Rate Base	10	1,883,901
Requested Jurisdictional Rate of Return	21	6.47%
Jurisdictional NOI Required		121,888
Less: Achieved Jurisdictional Adjusted NOI	12	76,359
Return Requirement (After Taxes)		45,529
Net Operating Income Multiplier	24	1.633971
Revenue Deficiency		74,393

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Gulf Power Company

Revenue Expansion Factor & NOI Multiplier
For the Test Year Ended
12/31/2014

Line No.	Description	Percent	Percent
1	Revenue Requirement		100.0000
2	Regulatory Assessment Rate		0.0720
3	Bad Debt Rate		0.2934
4	Net Before Income Taxes (1) - (2) - (3)		99.6346
5	State Income Tax Rate	5.5	5.5000
6	State Income Tax (4) x (5)		5.4799
7	Net Before Federal Income Tax (4) - (6)		94.1547
8	Federal Income Tax Rate	35.0	35.0000
9	Federal Income Tax (7) x (8)		32.9541
10	Revenue Expansion Factor (7) - (9)		61.2006
11	Net Operating Income Multiplier (100% / Line 10)		1.633971

Gulf Power Company
General Plant Capital Additions
For the Prior Year Ended 12/31/2013 and Test Year Ended 12/31/2014
(Thousands of Dollars)

	2013	2014
Office Furniture & Mechanical Equipment	140	233
Misc. Buildings, Land and Equipment	356	1,027
Security	133	180
Automobiles, Trucks and Equipment	3,002	3,340
Audio/Video Equipment/Print Services	36	65
Communications/Print Shop	36	65
Crestview Line Service Additions/Renovations	526	0
General Warehouse Shed Roof	257	0
Panama City Line Service Air Handler Unit 3-5	250	0
Pine Forest Parking Lot Resurface	361	0
Telecommunications Wireless & Scada	25	200
Power Delivery Technology Improvements	924	765
Voice & Data Converged Network	980	600
Telecommunications Transport & Facilities	670	800
Field Computing	75	151
T&D Warehouse Equipment Replacement	150	150
Pine Forest Building/New Office Space	8,062	0
Accounting, Supply Chain, & Work Order Management Systems	416	219
Tools And Test Equipment - Distribution	513	394
Tools And Test Equipment - Transmission	200	100
General Plant Capital Additions Total	**17,112**	**8,289**

Gulf Power Company
Compliance-Related Transmission (CRT) Investment and Expenses
Included in the Test Year Ended 12/31/2014
(Thousands of Dollars)

	(1) Total System	(2) Jurisdictional
Rate Base (13-Month Average for the Period Ended 12/31/14)		
Plant-in-Service	2,378	2,318
Accumulated Depreciation	(11)	(10)
Net Plant-in-Service	2,367	2,308
CWIP - Non Interest Bearing	4,225	4,110
Net Utility Plant	6,592	6,418
Net Operating Income (12 Months Ended 12/31/14)		
Depreciation Expense	35	34
Property Tax Expense	-	-
Income Tax Impact of Depreciation & Property Tax	(14)	(13)
Income Tax Impact of Interest Synchronization (p. 2)	(47)	(46)
Operating Expenses	(26)	(25)
Net Operating Income	26	25
Jurisdictional Revenue Requirement		
Rate Base		6,418
Jurisdictional Rate of Return		6.47%
Jurisdictional Return on Rate Base Included in 2014 Test Year		415
Less: Net Operating Income Included in 2014 Test Year		(25)
Subtotal		390
Times: NOI Multiplier		1.633971
Revenue Requirement Impact Included in 2014 Test Year		637

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130140-EI EXHIBIT 23
PARTY Gulf Power Company (Gulf) Direct
DESCRIPTION Susan D. Ritenour (SDR-2)
DATE

Gulf Power Company
Interest Synchronization Adjustment
Compliance-Related Transmission Investment and Expenses
Included in the Test Year Ended 12/31/2014
(Thousands of Dollars)

Total Company

Financing Source	Rate Base	Ratio (%)	Cost Rate (%)	Expense
Long-Term Debt	6,592	36.36	4.96	119
Short-Term Debt	6,592	1.47	0.82	1
Customer Deposits	6,592	1.11	2.30	2
ITC-Debt Component	6,592	0.05	4.96	-
Total Company Synchronized Interest				122
Federal Income Tax at 33.075%				40
State Income Tax at 5.5%				7
Total Company Income Tax				47

Jurisdictional

Financing Source	Rate Base	Ratio (%)	Cost Rate (%)	Expense
Long-Term Debt	6,418	36.36	4.96	116
Short-Term Debt	6,418	1.47	0.82	1
Customer Deposits	6,418	1.11	2.30	2
ITC-Debt Component	6,418	0.05	4.96	-
Total Jurisdictional Synchronized Interest				119
Federal Income Tax at 33.075%				39
State Income Tax at 5.5%				7
Total Jurisdictional Income Tax				46

Gulf Power Company
Calculation of Step Increase Effective July 1, 2015
For Compliance-Related Transmission (CRT) Costs
For the Period Ended June 30, 2016
(Thousnds of Dollars)

	(1) Total System	(2) Jurisdictional
Rate Base (13-Month Average for the Period Ended 6/30/16)		
Plant-in-Service	128,945	125,489
Accumulated Depreciation	(2,540)	(2,472)
Net Plant-in-Service	126,405	123,017
CWIP - Non Interest Bearing	-	-
Working Capital - Regulatory Asset (Schedule 3)	1,713	1,713
Net Utility Plant	128,118	124,730
Net Operating Income (12 Months Ended 6/30/16)		
Depreciation Expense	4,003	3,893
Amortization of Regulatory Asset	490	490
Property Tax Expense	914	889
Income Tax Impact of Depr., Amort. & Property Tax	(2,086)	(2,034)
Income Tax Impact of Interest Synchronization (p. 2)	(911)	(886)
Operating Expenses	2,410	2,352
Net Operating Income	(2,410)	(2,352)
Jurisdictional Revenue Requirement		
Rate Base		124,730
Jurisdictional Rate of Return		6.47%
Jurisdictional Return on Rate Base		8,070
Net Operating Income Required		2,352
Subtotal		10,422
Times: NOI Multiplier		1.633971
Total Revenue Required Associated With CRT Costs		17,029
Less: Revenue Requirement Included in 2014 Test Year (Schedule 1)		(637)
Revenue Requirement Required - 7/1/15 Step Increase		16,392

Gulf Power Company
Interest Synchronization Adjustment
Compliance-Related Transmission Investment and Expenses
For the Twelve Months Ended June 30, 2016
(Thousands of Dollars)

Total Company

Financing Source	Rate Base	Ratio (%)	Cost Rate (%)	Expense
Long-Term Debt	128,118	36.36	4.96	2,311
Short-Term Debt	128,118	1.47	0.82	15
Customer Deposits	128,118	1.11	2.30	33
ITC-Debt Component	128,118	0.05	4.96	3
Total Company Synchronized Interest				2,362
Federal Income Tax at 33.075%				781
State Income Tax at 5.5%				130
Total Company Income Tax				911

Jurisdictional

Financing Source	Rate Base	Ratio (%)	Cost Rate (%)	Expense
Long-Term Debt	124,730	36.36	4.96	2,249
Short-Term Debt	124,730	1.47	0.82	15
Customer Deposits	124,730	1.11	2.30	32
ITC-Debt Component	124,730	0.05	4.96	3
Total Jurisdictional Synchronized Interest				2,299
Federal Income Tax at 33.075%				760
State Income Tax at 5.5%				126
Total Jurisdictional Income Tax				886

Gulf Power Company
Compliance-Related Transmission (CRT) - Deferred Return / Regulatory Asset
(Thousands of Dollars)

	(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Beginning Bal	Bearing Ending Bal	Average Bal	Expense on CRT Plant-in-	CRT Investment (A)	Carrying Costs/ (B)	Asset Balance (C)
Dec 2014							-
Jan 2015	30,538	32,685	31,612	41	172	53	160
Feb 2015	32,685	34,102	33,394	41	183	53	331
Mar 2015	34,102	35,520	34,811	41	191	53	510
Apr 2015	35,520	53,150	44,335	41	244	53	742
May 2015	53,150	91,891	72,521	105	399	53	1,193
June 2015	91,891	124,963	108,427	221	597	53	1,958

Notes:

(A) The deferred return is calculated using Gulf's last approved AFUDC rate with an ROE of 11.5% as requested in this rate case. The calculation of the return is as follows:

	Average Balance of CRT Net Plant and CWIP
plus	Average of: [Beginning Balance of Regulatory Asset] and [Ending Balance of Regulatory Asset prior to inclusion of the current month Return***]
equals	Total
times	Monthly AFUDC rate
equals	**Monthly Return on Net CRT Investment and Regulatory Asset (Column 5)**

*** Ending Balance of Regulatory Asset prior to inclusion of the current month Return = Beginning Balance + current month Depreciation Expense (Col 4) - current month Carrying

(B) Exhibit SDR-2, Schedule 1: Revenue Requirement Impact/12

(C) Column 7 for the prior month + Columns 4 through 6

Gulf Power Company
Compliance-Related Transmission (CRT) - Regulatory Asset / Annual Amortization
(Thousands of Dollars)

Calculation of Amortization of Regulatory Asset:

Projected June 30, 2015 Regulatory Asset (p. 1)	1,958
Divided by: 4 years	4
Annual Amortization	490
13 Month Average Regulatory Asset - Period Ending 6/30/16	1,713

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Witness: Michael T. O'Sheasy
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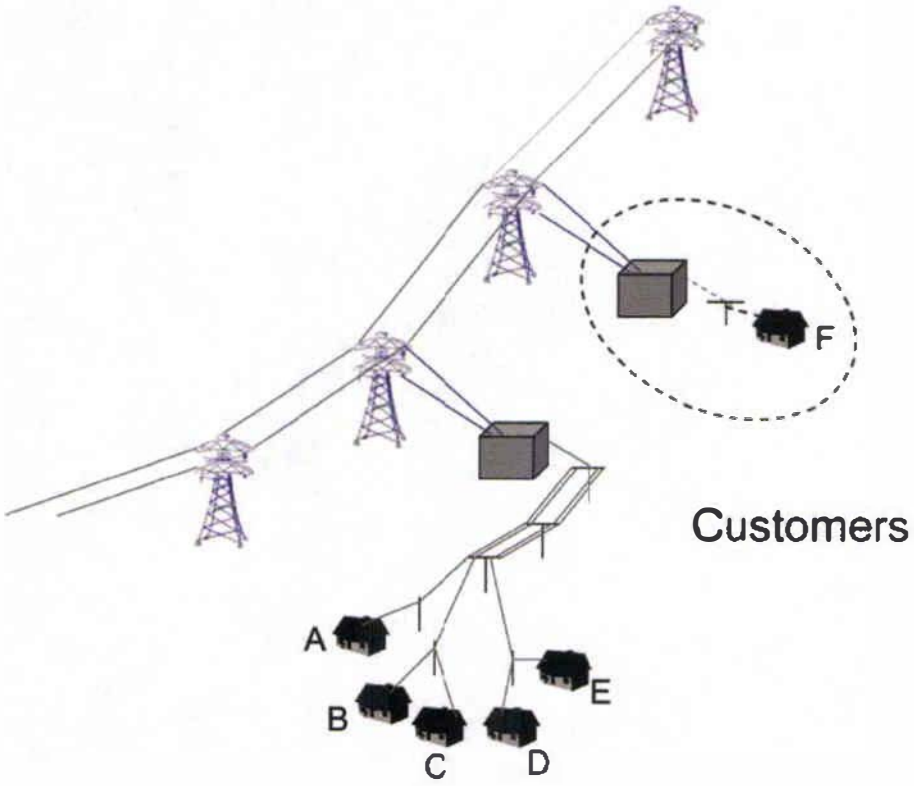
Responsibility for Minimum Filing Requirements

Schedule	Title
B-6	Jurisdictional Separation Factors – Rate Base
C-4	Jurisdictional Separation Factors – Net Operating Income
E-1	Cost of Service Studies
E-2	Explanation of Variations from Cost of Service Study Approved in Company's Last Rate Case
E-3a	Cost of Service Study – Allocation of Rate Base Components to Rate Schedule
E-3b	Cost of Service Study – Allocation of Expense Components to Rate Schedule
E-4a	Cost of Service Study – Functionalization and Classification of Rate Base
E-4b	Cost of Service Study – Functionalization and Classification of Expenses
E-5	Source and Amount of Revenues – At Present and Proposed Rates
E-6a	Cost of Service Study – Unit Costs, Present Rates
E-6b	Cost of Service Study – Unit Costs, Proposed Rates
E-9	Cost of Service – Load Data
E-10	Cost of Service Study – Development of Allocation Factors
E-11	Development of Coincident and Non-Coincident Demands for Cost Study
E-16	Customers by Voltage Level
E-19a	Demand and Energy Losses
E-19b	Energy Losses
E-19c	Demand Losses

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130140-EI EXHIBIT 24
PARTY Gulf Power Company (Gulf) Direct
DESCRIPTION Michael T. O'Sheasy (MTO-1)
DATE

Illustration of Simple Distribution Network



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FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130140-EI EXHIBIT 25
PARTY Gulf Power Company (Gulf) Direct
DESCRIPTION Michael T. O'Sheasy (MTO-2)
DATE

GULF POWER COMPANY
12 MONTHS ENDING DECEMBER 31, 2014
12/13 DEMAND ALLOCATION - WITH MDS METHODOLOGY
SCHEDULE 1.00 - PRESENT RATE SUMMARY
($000'S)

LINE NO. (1)	DESCRIPTION (2)	TOTAL ELECTRIC SYSTEM (3)	RATE CLASS RESIDENTIAL (4)	RATE CLASS GS (5)	RATE CLASS GSD/GSDT (6)	RATE CLASS LP/LPT (7)	RATE CLASS MAJOR ACCTS (8)	RATE CLASS OS (9)	TOTAL RETAIL SERVICE (10)	WHOLESALE (11)	UNIT POWER SALES (12)
	INVESTMENT										
1	ELECTRIC GROSS PLANT	3,391,076	1,720,955	99,776	580,715	225,760	227,889	89,073	2,944,168	55,729	391,179
2	ACCUMULATED DEPRECIATION	1,398,044	725,208	41,095	240,957	94,574	98,249	43,236	1,243,319	24,730	129,995
3	NET PLANT	1,993,032	995,747	58,681	339,758	131,186	129,640	45,837	1,700,849	30,999	261,184
4	MATERIALS AND SUPPLIES	154,358	70,673	3,801	33,712	14,556	15,953	2,316	141,011	3,814	9,533
5	OTHER WORKING CAPITAL	12,616	7,802	490	2,508	1,122	1,140	249	13,311	316	(1,011)
6	CONST. WORK IN PROGRESS	0	0	0	0	0	0	0	0	0	0
7	CWIP - NOT BEARING INTEREST	33,647	15,090	799	5,543	2,255	2,479	490	26,656	634	6,557
8	PLANT HELD FOR FUTURE USE	5,435	2,883	144	1,146	487	588	28	5,276	159	0
9	UNAMORT. PLANT ACQ. ADJUST.	1,903	0	0	0	0	0	0	0	0	1,903
10	INJURIES AND DAMAGES RESERVE	(3,354)	(2,027)	(163)	(555)	(194)	(204)	(59)	(3,202)	(54)	(98)
11	TOTAL ELECTRIC INVESTMENT	2,197,837	1,090,168	63,752	382,112	149,412	149,596	48,861	1,883,901	35,868	278,068
	REVENUES										
12	REVENUE FROM SALES	510,734	296,890	20,537	102,785	33,933	29,452	14,896	498,493	12,241	0
13	OTHER OPERATING REVENUES	69,171	37,651	2,359	11,161	9,377	3,320	1,401	65,278	3,893	0
14	REVENUE-NONASSOCIATED SALES	65,602	3,389	186	1,760	784	907	99	7,127	214	58,261
15	ADJUSTMENTS TO REVENUE	(42,247)	(25,162)	(1,740)	(8,711)	(2,676)	(2,496)	(1,262)	(42,247)	(0)	0
16	TOTAL ADJUSTED REVENUE	603,260	312,768	21,353	108,995	41,218	31,183	15,134	528,651	16,348	58,261
	EXPENSE										
17	OPERATIONS & MAINTENANCE	308,608	175,167	12,649	51,582	24,872	20,427	5,622	290,199	5,717	12,692
18	DEPRECIATION	114,402	61,471	3,747	20,152	7,658	7,716	3,761	104,505	1,922	7,975
19	AMORT. OF INV. TAX CREDIT	(1,224)	(517)	(31)	(169)	(64)	(65)	(32)	(878)	(16)	(330)
20	OTHER AMORTIZATION	0	0	0	0	0	0	0	0	0	0
21	REAL & PERSONAL PROP. TAX	26,010	13,696	758	5,040	2,083	2,245	495	24,515	580	915
22	PAYROLL TAX	6,917	4,108	332	1,180	415	437	127	6,599	114	204
23	REVENUE TAX	402	239	17	83	27	24	12	402	0	0
24	OTHER TAXES	41,572	24,744	1,709	8,569	2,835	2,471	1,233	41,561	11	0
25	ADJUSTMENT TO OTHER TAXES	(41,160)	(24,514)	(1,696)	(8,487)	(2,802)	(2,431)	(1,230)	(41,160)	0	0
26	EXPENSES EXCL. INC. TAX	455,527	254,594	17,393	77,930	35,024	30,824	9,988	425,743	8,328	21,456
27	OPERATING INCOME	147,733	58,174	3,970	29,065	6,194	359	5,146	102,908	8,020	36,805
28	STATE & FEDERAL INCOME TAX	34,676	10,889	856	7,163	806	(1,446)	1,467	19,735	2,714	12,227
29	INTEREST SYNCHRONIZATION	6,925	3,943	231	1,382	540	541	177	6,814	111	0
30	TOTAL INCOME TAXES	41,601	14,832	1,087	8,545	1,346	(905)	1,644	26,549	2,825	12,227
31	NET OPERATING INCOME	106,132	43,342	2,883	20,520	4,848	1,264	3,502	76,359	5,195	24,578
32	RATE OF RETURN	4.83%	3.98%	4.52%	5.37%	3.24%	0.84%	7.17%	4.05%		
33	RATE OF RETURN INDEX		98.09%	111.57%	132.49%	80.05%	20.85%	176.83%	100.00%		

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GULF POWER COMPANY
12 MONTHS ENDED DECEMBER 31, 2014
12/13 DEMAND ALLOCATION - WITH MDS METHODOLOGY
PRESENT RATE SUMMARY

Line No.	Ftnt Label	Description
1	(A)	From "Analysis of Gross Plant"
2	(B)	From "Analysis of Accumulated Depreciation Reserve"
4	(C)	From "Analysis of Materials and Supplies"
5	(D)	From "Analysis of Other Working Capital"
6	(E)	From "Analysis of Other Rate Base Items"
7	(E)	
8	(E)	
9	(E)	
10	(E)	
12	(F)	From "Analysis of Revenues"
13	(F)	
14	(F)	
15	(F)	
17	(G)	From "Analysis of Operations and Maintenance Expense"
18	(H)	From "Analysis of Depreciation Expense"
19	(I)	Allocated per Depreciation Expense; UPS directly assigned
20	(J)	Allocated per Total Production Gross Plant excluding UPS
21	(K)	From "Analysis of Taxes Other Than Income Taxes"
22	(K)	
23	(K)	
24	(K)	
25	(K)	
28	(L)	Income Taxes allocated per formula t = Rc - KI : where t = Total Income Taxes, R = Operating Income, c = Combined Effective Tax Rate of 0.38575, I = Total Electric Investment, and K = Income Tax Deduction factor of 0.0105957953; UPS directly assigned.
29	(M)	Retail portion allocated per Retail Rate Base; Total All Other and UPS directly assigned.
32	(N)	Rate of Return equals Net Operating Income Divided by Total Electric Investment.
33	(O)	Each Rate Class Rate of Return divided by Total Retail Service Rate of Return

GULF POWER COMPANY
12 MONTHS ENDING DECEMBER 31, 2014
12/13 DEMAND ALLOCATION - WITH MDS METHODOLOGY
SCHEDULE 1.01 - EQUAL RATE OF RETURN SUMMARY - PRESENT RATES
($000'S)

LINE NO. (1)	DESCRIPTION (2)	TOTAL RETAIL SERVICE (3)	RATE CLASS RESIDENTIAL (4)	RATE CLASS GS (5)	RATE CLASS GSD/GSDT (6)	RATE CLASS LP/LPT (7)	RATE CLASS MAJOR ACCTS (8)	RATE CLASS OS (9)
1	EQUAL RATE OF RETURN	4.05%	4.05%	4.05%	4.05%	4.05%	4.05%	4.05%
2	PRESENT SYSTEM OPERATING INCOME	76,359	44,188	2,584	15,488	6,056	6,063	1,980
3	CURRENT OPERATING INCOME	76,359	43,342	2,883	20,520	4,848	1,264	3,502
4	CHANGE IN OPERATING INCOME	(0)	846	(299)	(5,032)	1,208	4,799	(1,522)
5	CHANGE IN INCOME TAXES	0	531	(188)	(3,160)	759	3,014	(956)
6	CURRENT INCOME TAXES	26,549	14,832	1,087	8,545	1,346	(905)	1,644
7	CHANGE IN EXPENSES	0	4	(2)	(30)	7	30	(9)
8	CURRENT EXPENSES	425,743	254,594	17,383	77,930	35,024	30,824	9,988
9	REV REQ - EQUAL SYSTEM ROR - PRESENT RATES	528,651	314,149	20,864	98,773	43,192	39,026	12,647
10	PRESENT REVENUE REQUIREMENTS	528,651	312,768	21,353	106,995	41,218	31,183	15,134
11	REVENUE EXCESS / DEFICIENCY	(0)	1,381	(489)	(8,222)	1,974	7,843	(2,487)
12	REV REQ INDEX - EQUAL SYSTEM ROR - PRES. RATES	100.00%	99.56%	102.34%	108.32%	95.43%	79.90%	119.66%

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GULF POWER COMPANY
12 MONTHS ENDING DECEMBER 31, 2014
12/13 DEMAND ALLOCATION - WITH MDS METHODOLOGY
SCHEDULE 1.10 - PROPOSED RATE SUMMARY
($000'S)

LINE NO. (1)	DESCRIPTION (2)	TOTAL ELECTRIC SYSTEM (3)	RATE CLASS RESIDENTIAL (4)	RATE CLASS GS (5)	RATE CLASS GSD/GSDT (6)	RATE CLASS LP/LPT (7)	RATE CLASS MAJOR ACCTS (8)	RATE CLASS OS (9)	TOTAL RETAIL SERVICE (10)	WHOLESALE (11)	UNIT POWER SALES (12)
1	TOTAL ELECTRIC INVESTMENT	2,197,837	1,090,168	63,752	392,112	149,412	149,596	48,861	1,893,901	35,868	278,068
	REVENUE										
2	PRESENT REVENUE	603,260	312,768	21,353	108,995	41,218	31,183	15,134	528,651	16,348	58,261
3	PROPOSED REVENUE	74,393	44,303	2,372	13,194	7,104	8,570	850	74,393	0	0
4	TOTAL REVENUE	677,653	357,071	23,725	120,189	48,322	37,753	15,984	603,044	16,348	58,261
	EXPENSE										
5	PRESENT OPERATING EXPENSES	455,627	254,594	17,383	77,930	35,024	30,824	9,988	425,743	8,328	21,456
6	PROPOSED EXPENSE INCREASE	272	162	9	48	26	24	3	272	0	0
7	TOTAL EXPENSES	455,799	254,756	17,392	77,978	35,050	30,848	9,991	426,015	8,328	21,456
8	OPERATING INCOME	221,854	102,315	6,333	42,211	13,272	6,905	5,993	177,029	8,020	36,805
	INCOME TAXES										
9	PRESENT INCOME TAXES	41,601	14,832	1,087	8,545	1,346	(905)	1,644	28,549	2,825	12,227
10	PROPOSED INC. TAX INCREASE	28,592	17,027	912	5,071	2,730	2,525	327	28,592	0	0
11	TOTAL INCOME TAXES	70,193	31,859	1,999	13,616	4,076	1,620	1,971	55,141	2,825	12,227
12	NET OPERATING INCOME	151,661	70,456	4,334	28,595	9,196	5,285	4,022	121,888	5,195	24,578
13	RATE OF RETURN	6.90%	6.46%	6.80%	7.48%	6.15%	3.53%	8.23%	6.47%		
14	RATE OF RETURN INDEX		99.89%	105.07%	115.66%	95.13%	54.60%	127.23%	100.00%		

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GULF POWER COMPANY
12 MONTHS ENDED DECEMBER 31, 2014
12/13 DEMAND ALLOCATION - WITH MDS METHODOLOGY
PROPOSED RATE SUMMARY

Line No.	Ftnt Label	Description
1	(A)	From "Present Rate Summary"
2	(A)	
3	(B)	Provided by Pricing, Costing & Load Research, Gulf Power Company.
5	(A)	
6	(C)	Calculated by multiplying Proposed Revenues times the appropriate Proposed Expense Factor
8	(D)	Operating Income equals Total Revenue minus Total Expenses.
9	(A)	
10	(E)	Proposed Income Tax Increase calculated by multiplying Proposed Revenue minus Proposed Expense Increase times Effective Tax Rate of 0.38575.
12	(F)	Net Operating Income equals Operating Income less Total Income Taxes.
13	(G)	Rate of Return equals Net Operating Income Divided by Total Electric Investment.
14	(H)	Each Rate Class Rate of Return divided by Total Retail Service Rate of Return

GULF POWER COMPANY
12 MONTHS ENDING DECEMBER 31, 2014
12/13 DEMAND ALLOCATION - WITH MDS METHODOLOGY
SCHEDULE 1.11 - EQUAL RATE OF RETURN SUMMARY - PROPOSED RATES
($000'S)

LINE NO. (1)	DESCRIPTION (2)	TOTAL RETAIL SERVICE (3)	RATE CLASS RESIDENTIAL (4)	RATE CLASS GS (5)	RATE CLASS GSD/GSDT (6)	RATE CLASS LP/LPT (7)	RATE CLASS MAJOR ACCTS (8)	RATE CLASS OS (9)
1	EQUAL RATE OF RETURN	6.47%	6.47%	6.47%	6.47%	6.47%	6.47%	6.47%
2	PROPOSED OPERATING INCOME	121,888	70,534	4,125	24,723	9,667	9,679	3,161
3	CURRENT OPERATING INCOME	76,359	43,342	2,883	20,520	4,848	1,264	3,502
4	CHANGE IN OPERATING INCOME	45,530	27,192	1,242	4,203	4,819	8,415	(341)
5	CHANGE IN INCOME TAXES	28,592	17,076	780	2,639	3,026	5,285	(214)
6	PRESENT INCOME TAXES	26,549	14,832	1,087	8,545	1,348	(905)	1,644
7	CHANGE IN EXPENSES	273	162	7	25	29	51	(2)
8	PRESENT EXPENSES	425,743	254,594	17,383	77,930	35,024	30,824	9,988
9	REV REQ - EQUAL SYSTEM ROR - PROPOSED RATES	603,045	357,198	23,382	113,861	49,092	44,934	14,577
10	PRESENT REVENUE REQUIREMENTS	528,651	312,768	21,353	106,995	41,218	31,183	15,134
11	REVENUE EXCESS / DEFICIENCY	74,393	44,430	2,029	6,866	7,874	13,751	(557)
12	REV REQ INDEX - EQUAL SYSTEM ROR - PROP. RATES	87.66%	87.56%	91.32%	93.97%	83.96%	69.40%	103.82%

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GULF POWER COMPANY
12 MONTHS ENDED DECEMBER 31, 2014
12/13 DEMAND ALLOCATION - WITH MDS METHODOLOGY
EQUAL RATE OF RETURN SUMMARY - PROPOSED RATES

Line No.	Ftnt Label	Description
1	(A)	From "Proposed Rate Summary", Total Retail Service Rate of Return
2	(B)	Line 1 times Total Rate Base - "Proposed Rate Summary"
3	(C)	From "Present Rate Summary"
4	(D)	Line 2 minus Line 3
5	(E)	Line 4 times the combined effective tax rate divided by 1 minus the combined effective tax rate
6	(C)	
7	(F)	Line 4 plus Line 5 times the Proposed Expense Factor divided by 1 minus the Proposed Expense Factor
8	(C)	
9	(G)	Line 2 plus Lines 5 - 8.
10	(C)	
11	(H)	Line 9 minus Line 10
12	(I)	Line 10 divided by Line 9

GULF POWER COMPANY
12 MONTHS ENDING DECEMBER 31, 2014
12/13 DEMAND ALLOCATION - WITH MDS METHODOLOGY
SCHEDULE 2.10 - ANALYSIS OF GROSS PLANT
($000'S)

LINE NO. (1)	DESCRIPTION (2)	TOTAL ELECTRIC SYSTEM (3)	RATE CLASS RESIDENTIAL (4)	RATE CLASS GS (5)	RATE CLASS GSD/GSDT (6)	RATE CLASS LP/LPT (7)	RATE CLASS MAJOR ACCTS (8)	RATE CLASS OS (9)	TOTAL RETAIL SERVICE (10)	WHOLESALE (11)	UNIT POWER SALES (12)
1	TOTAL PRODUCTION PLANT	1,571,047	627,458	30,656	252,627	107,929	130,774	5,721	1,155,365	35,508	380,174
	RETAIL JURISDICTION										
2	DEMAND		585,178	28,617	230,676	98,157	119,476	4,467	1,066,491		
3	ENERGY		42,280	2,339	21,951	9,772	11,298	1,234	88,874		
	TRANSMISSION PLANT										
	350-LAND & LAND RIGHTS										
1	SUBSTATIONS										
4	LEVEL 2 COMMON	1,541	821	40	323	138	167	6	1,495	46	0
5	LEVEL 3 COMMON	591	351	17	138	51	31	3	591	0	0
6	TOTAL SUBSTATION LAND	2,132	1,172	57	461	189	198	9	2,086	46	0
	LINES										
7	LEVEL 2 COMMON	18,183	9,678	472	3,816	1,624	1,977	74	17,641	542	0
8	TOTAL ACCOUNT 350	20,315	10,850	529	4,277	1,813	2,175	83	19,727	588	0
	352-STRUCTURES										
9	LEVEL 2 CUSTOMER SUB	2	0	0	0	0	2	0	2	0	0
10	LEVEL 2 COMMON	9,550	5,083	248	2,004	853	1,038	39	9,265	285	0
11	LEVEL 3 COMMON	1,439	853	42	337	125	75	7	1,439	0	0
12	TOTAL ACCOUNT 352	10,991	5,936	290	2,341	978	1,115	46	10,706	285	0
	353-STATION EQUIPMENT										
13	LEVEL 2 CUSTOMER SUB	140	0	0	0	0	140	0	140	0	0
14	LEVEL 2 COMMON	125,698	63,534	3,096	25,045	10,657	12,971	487	115,790	3,559	6,347
15	LEVEL 3 COMMON	38,170	22,657	1,104	8,931	3,305	1,999	174	38,170	0	0
16	TOTAL ACCOUNT 353	164,008	86,191	4,200	33,976	13,962	15,110	661	154,100	3,559	6,347
	354-TOWERS AND FIXTURES										
17	LEVEL 2 COMMON	42,804	22,787	1,110	8,982	3,822	4,652	175	41,528	1,276	0
	355-POLES AND FIXTURES										
18	LEVEL 2 COMMON	148,976	79,305	3,865	31,262	13,302	16,192	608	144,534	4,442	0
	356-OVERHEAD CONDUCTORS										
19	LEVEL 2 COMMON	85,526	45,529	2,219	17,947	7,637	9,295	349	82,976	2,550	0
	358-UNDERGROUND CONDUCTORS										
20	LEVEL 2 COMMON	14,095	7,502	366	2,958	1,259	1,532	58	13,675	420	0
	359-ROADS AND TRAILS										
21	LEVEL 2 COMMON	236	126	6	50	21	25	1	229	7	0
22	TOTAL TRANS. PLANT	486,949	258,226	12,585	101,793	42,794	50,086	1,981	467,475	13,127	6,347

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GULF POWER COMPANY
12 MONTHS ENDING DECEMBER 31, 2014
12/13 DEMAND ALLOCATION - WITH MDS METHODOLOGY
SCHEDULE 2.10 - ANALYSIS OF GROSS PLANT
($000'S)

LINE NO. (1)	DESCRIPTION (2)	TOTAL ELECTRIC SYSTEM (3)	RATE CLASS RESIDENTIAL (4)	RATE CLASS GS (5)	RATE CLASS GSD/GSDT (6)	RATE CLASS LP/LPT (7)	RATE CLASS MAJOR ACCTS (8)	RATE CLASS OS (9)	TOTAL RETAIL SERVICE (10)	WHOLESALE (11)	UNIT POWER SALES (12)
	DISTRIBUTION PLANT										
	360-SUBSTATION LAND										
23	LEVEL 3 CUST. SUB	74	0	0	0	0	11	0	11	62	0
24	LEVEL 3 COMMON	4,584	2,720	133	1,073	397	240	21	4,584	0	0
25	LEVEL 4 COMMON	12	6	0	3	1	0	0	12	0	0
26	TOTAL ACCOUNT 360	4,670	2,728	133	1,076	398	251	21	4,607	62	0
	361-STRUCTURES										
27	LEVEL 3 CUST. SUB	2,007	0	0	0	617	963	0	1,581	426	0
28	LEVEL 3 COMMON	21,220	12,596	614	4,965	1,837	1,111	97	21,220	0	0
29	LEVEL 4 COMMON	0	0	0	0	0	0	0	0	0	0
30	TOTAL ACCOUNT 361	23,227	12,596	614	4,965	2,454	2,074	97	22,801	426	0
	362-STATION EQUIPMENT										
31	LEVEL 3 CUST. SUB	20,433	0	0	0	4,195	12,566	0	16,761	3,672	0
32	LEVEL 3 COMMON	205,570	122,021	5,946	48,100	17,799	10,768	936	205,570	0	0
33	LEVEL 4 COMMON	23	13	1	6	2	1	0	23	0	0
34	TOTAL ACCOUNT 362	226,026	122,034	5,947	48,106	21,996	23,335	936	222,354	3,672	0
	364-POLES AND FIXTURES										
35	LEVEL 4 COMMON	35,454	20,686	1,116	6,647	3,138	1,334	531	35,454	0	0
36	LEVEL 4 CUSTOMER	68,500	59,649	4,505	2,703	43	7	1,593	68,500	0	0
37	LEVEL 5 COMMON	10,168	5,310	341	2,621	715	19	162	10,168	0	0
38	LEVEL 5 CUSTOMER	19,667	17,128	1,294	775	11	1	458	19,667	0	0
39	TOTAL ACCOUNT 364	133,789	103,773	7,258	14,746	3,907	1,361	2,744	133,789	0	0
	365-OVERHEAD CONDUCTORS										
40	LEVEL 4 COMMON	89,998	52,507	2,838	21,951	7,987	3,367	1,348	89,998	0	0
41	LEVEL 4 CUSTOMER	17,614	15,339	1,158	695	11	2	410	17,614	0	0
42	LEVEL 5 COMMON	25,183	16,627	844	6,491	1,772	48	401	25,183	0	0
43	LEVEL 5 CUSTOMER	4,616	4,194	317	190	3	0	112	4,616	0	0
44	TOTAL ACCOUNT 365	137,611	87,666	5,157	29,327	9,753	3,437	2,271	137,611	0	0
	366-UNDERGROUND CONDUIT										
45	LEVEL 4 COMMON	664	397	21	162	59	25	10	664	0	0
46	LEVEL 4 CUSTOMER	33	29	2	1	0	0	1	33	0	0
47	LEVEL 5 COMMON	450	279	15	116	32	1	7	450	0	0
48	LEVEL 5 CUSTOMER	14	12	1	1	0	0	0	14	0	0
49	TOTAL ACCOUNT 366	1,161	707	39	280	91	26	18	1,161	0	0
	367-UNDERGROUND COND. & DEV.										
50	LEVEL 4 COMMON	99,396	57,991	3,134	24,243	8,799	3,740	1,489	99,396	0	0
51	LEVEL 4 CUSTOMER	4,645	4,216	319	191	3	1	113	4,645	0	0
52	LEVEL 5 COMMON	40,669	25,235	1,364	10,483	2,881	78	648	40,669	0	0
53	LEVEL 5 CUSTOMER	1,908	1,663	125	75	1	0	44	1,908	0	0
54	TOTAL ACCOUNT 367	146,616	89,107	4,942	34,992	11,664	3,819	2,294	146,616	0	0

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GULF POWER COMPANY
12 MONTHS ENDING DECEMBER 31, 2014
12/13 DEMAND ALLOCATION - WITH MDS METHODOLOGY
SCHEDULE 2.10 - ANALYSIS OF GROSS PLANT
($000'S)

LINE NO. (1)	DESCRIPTION (2)	TOTAL ELECTRIC SYSTEM (3)	RATE CLASS RESIDENTIAL (4)	RATE CLASS GS (5)	RATE CLASS GSD/GSDT (6)	RATE CLASS LP/LPT (7)	RATE CLASS MAJOR ACCTS (8)	RATE CLASS OS (9)	TOTAL RETAIL SERVICE (10)	WHOLESALE (11)	UNIT POWER SALES (12)
	368-LINE TRANSFORMERS										
55	LEVEL 4 COMMON	35,271	20,579	1,112	8,603	3,122	1,327	528	35,271	0	0
56	LEVEL 4 CUSTOMER	4,314	3,757	284	170	3	0	100	4,314	0	0
57	LEVEL 5 COMMON	154,026	95,575	5,165	39,703	10,835	294	2,454	154,026	0	0
58	LEVEL 5 CUSTOMER	60,139	52,376	3,956	2,370	34	4	1,399	60,139	0	0
59	TOTAL ACCOUNT 368	253,750	172,287	10,517	50,846	13,994	1,625	4,481	253,750	0	0
	369-SERVICES										
60	HOUSE POWER BOXES	0	0	0	0	0	0	0	0	0	0
61	OTHER SERVICES	99,675	88,877	6,712	4,021	57	8	0	99,675	0	0
62	TOTAL ACCOUNT 369	99,675	88,877	6,712	4,021	57	8	0	99,675	0	0
63	370-METERS	65,096	48,578	6,437	8,768	494	266	138	64,981	115	0
64	373-STREET LIGHTING	65,351	0	0	0	0	0	65,351	65,351	0	0
65	TOTAL DIST. PLANT	1,157,174	728,653	47,756	197,127	64,809	35,203	78,351	1,152,898	4,276	0
66	DEMAND	745,202	432,534	22,646	177,167	64,148	35,914	8,632	741,041	4,161	0
67	CUSTOMER	411,972	296,119	25,110	19,960	660	289	69,719	411,857	115	0
	GENERAL PLANT										
68	ELECTRIC	175,908	108,618	8,579	29,168	10,228	10,817	3,020	168,430	2,818	4,658
69	DEMAND	108,101	55,114	2,737	21,951	8,928	9,487	597	98,814	2,629	4,658
70	CUSTOMER	63,809	48,660	5,695	5,736	642	567	2,340	63,620	189	0
71	ENERGY	5,998	2,854	157	1,481	658	763	83	5,996	0	0
72	TOTAL GENERAL PLANT	175,908	108,618	8,579	29,168	10,228	10,817	3,020	168,430	2,818	4,658
73	TOTAL ELEC. GROSS PLANT	3,391,076	1,720,955	99,776	580,715	225,760	227,889	89,073	2,944,168	55,729	391,179
74	DEMAND	2,620,424	1,331,052	66,485	531,587	214,026	214,972	15,697	2,373,821	55,425	391,179
75	CUSTOMER	475,781	344,769	30,795	25,696	1,302	856	72,059	475,477	304	0
76	ENERGY	94,870	45,134	2,496	23,432	10,430	12,061	1,317	94,870	0	0

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12/13 DEMAND ALLOCATION - WITH MDS METHODOLOGY
ANALYSIS OF GROSS PLANT

Line No.	Ftnt Label	Description
1	(A)	Retail jurisdiction sum of Lines 2 and 3; Wholesale allocated per Level 1 Demand Allocator; UPS directly assigned.
2	(B)	Allocated per corresponding Level 1 Demand Allocator.
3	(C)	Allocated per corresponding Level 1 Energy Allocator.
4	(D)	Allocated per Level 2 Demand Allocator; UPS directly assigned.
5	(E)	Allocated per Level 3 Demand Allocator.
7	(D)	
9	(F)	Specific Assignment
10	(D)	
11	(E)	
13	(F)	
14	(D)	
15	(E)	
17	(D)	
18	(D)	
19	(D)	
20	(D)	
21	(D)	
23	(F)	
24	(E)	
25	(G)	Allocated per Level 4 NCP Demand Allocator
27	(F)	
28	(E)	
29	(G)	
31	(F)	
32	(E)	
33	(G)	
35	(G)	
36	(H)	Allocated per Average Number of Customers at Level 4 and Level 5.
37	(I)	Allocated per Level 5 NCP Demand Allocator
38	(J)	Allocated per Average Number of Customers at Level 5.

GULF POWER COMPANY
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12/13 DEMAND ALLOCATION - WITH MDS METHODOLOGY
ANALYSIS OF GROSS PLANT

Line No.	Ftnt Label	Description
40	(G)	
41	(H)	
42	(I)	
43	(J)	
45	(G)	
46	(H)	
47	(I)	
48	(J)	
50	(G)	
51	(H)	
52	(I)	
53	(J)	
55	(G)	
56	(H)	
57	(I)	
58	(J)	
60	(F)	
61	(K)	Allocated per Average Number of Customers at Level 5 excluding Rate OS.
63	(L)	Provided by Gulf Power Company
64	(F)	
68	(M)	Allocated per corresponding Salaries and Wages; UPS directly assigned.
69	(M)	
70	(M)	
71	(M)	

GULF POWER COMPANY
12 MONTHS ENDING DECEMBER 31, 2014
12/13 DEMAND ALLOCATION - WITH MDS METHODOLOGY
SCHEDULE 2.20 - ANALYSIS OF ACCUMULATED DEPRECIATION RESERVE
($000'S)

LINE NO. (1)	DESCRIPTION (2)	TOTAL ELECTRIC SYSTEM (3)	RATE CLASS RESIDENTIAL (4)	RATE CLASS GS (5)	RATE CLASS GSD/GSDT (6)	RATE CLASS LP/LPT (7)	RATE CLASS MAJOR ACCTS (8)	RATE CLASS OS (9)	TOTAL RETAIL SERVICE (10)	WHOLESALE (11)	UNIT POWER SALES (12)
1	TOTAL PRODUCTION	759,866	334,127	16,432	134,526	57,474	69,638	3,046	615,243	18,909	125,715
	RETAIL JURISDICTION										
2	DEMAND		311,613	15,186	122,637	52,270	63,622	2,389	567,917		
3	ENERGY		22,514	1,246	11,889	5,204	6,016	657	47,326		
	TRANSMISSION										
4	350-LAND AND LAND RIGHTS	6,816	3,629	177	1,430	609	740	28	6,613	203	0
5	352-STRUCTURES	3,645	1,969	96	776	324	370	15	3,550	95	0
6	353-STATION EQUIPMENT	32,146	16,252	792	6,406	2,633	2,849	125	29,057	671	2,418
7	354-TOWERS & FIXTURES	25,433	13,539	660	5,337	2,271	2,764	104	24,675	758	0
8	355-POLES & FIXTURES	26,313	14,007	683	5,522	2,349	2,860	107	25,528	785	0
9	356-OVERHEAD COND.	26,168	13,930	679	5,491	2,337	2,844	107	25,388	780	0
10	358-UNDERGROUND COND.	7,657	4,075	199	1,607	684	832	32	7,429	228	0
11	359-ROADS AND TRAILS	40	22	1	6	4	4	0	39	1	0
12	TOTAL TRANSMISSION	128,218	67,423	3,287	26,577	11,211	13,263	518	122,279	3,521	2,418
	DISTRIBUTION										
13	360-SUBSTATION LAND	35	21	1	8	3	2	0	35	0	0
14	361-STRUCTURES	7,861	4,262	208	1,680	831	703	33	7,717	144	0
15	362-STATION EQUIPMENT	61,193	33,040	1,610	13,024	5,955	6,317	253	60,199	994	0
	364-POLES & FIXTURES										
16	COMMON	23,472	13,889	751	5,797	1,982	696	357	23,472	0	0
17	CUSTOMER	45,360	39,499	2,983	1,791	28	4	1,055	45,360	0	0
18	TOTAL ACCOUNT 364	68,832	53,388	3,734	7,588	2,010	700	1,412	68,832	0	0
	365-OVERHEAD COND.										
19	COMMON	40,725	24,091	1,302	10,056	3,443	1,215	618	40,725	0	0
20	CUSTOMER	7,931	6,907	521	313	5	0	185	7,931	0	0
21	TOTAL ACCOUNT 365	48,656	30,998	1,823	10,369	3,448	1,215	803	48,656	0	0

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12 MONTHS ENDING DECEMBER 31, 2014
12/13 DEMAND ALLOCATION - WITH MDS METHODOLOGY
SCHEDULE 2.20 - ANALYSIS OF ACCUMULATED DEPRECIATION RESERVE
($000'S)

LINE NO. (1)	DESCRIPTION (2)	TOTAL ELECTRIC SYSTEM (3)	RATE CLASS RESIDENTIAL (4)	RATE CLASS GS (5)	RATE CLASS GSD/GSDT (6)	RATE CLASS LP/LPT (7)	RATE CLASS MAJOR ACCTS (8)	RATE CLASS OS (9)	TOTAL RETAIL SERVICE (10)	WHOLESALE (11)	UNIT POWER SALES (12)
	368-UNDG. CONDUIT										
22	COMMON	768	457	25	193	63	16	12	768	0	0
23	CUSTOMER	32	29	2	1	0	0	0	32	0	0
24	TOTAL ACCOUNT 368	800	486	27	194	63	16	12	800	0	0
	367-UNDERGROUND COND. & DEV.										
25	COMMON	50,298	29,887	1,815	12,471	4,187	1,371	767	50,298	0	0
26	CUSTOMER	2,425	2,110	160	96	2	0	57	2,425	0	0
27	TOTAL ACCOUNT 367	52,723	31,997	1,775	12,567	4,189	1,371	824	52,723	0	0
	368-LINE TRANSFORMERS										
28	COMMON	69,302	42,524	2,298	17,685	5,110	593	1,092	69,302	0	0
29	CUSTOMER	23,597	20,551	1,562	930	13	2	549	23,597	0	0
30	TOTAL ACCOUNT 368	92,899	63,075	3,860	18,615	5,123	595	1,641	92,899	0	0
31	369-SERVICES	50,634	45,327	3,423	2,051	29	4	0	50,634	0	0
32	370-METERS	21,743	18,057	1,464	1,993	112	60	31	21,717	26	0
33	373-STREET LIGHTING	33,445	0	0	0	0	0	33,445	33,445	0	0
34	TOTAL DISTRIBUTION	439,021	280,651	17,915	68,089	21,763	10,995	38,454	437,857	1,164	0
35	DEMAND	253,654	148,171	7,810	60,914	21,574	10,915	3,132	252,518	1,136	0
36	CUSTOMER	185,367	132,480	10,105	7,175	189	70	35,322	185,341	26	0
	GENERAL PLANT										
	ELECTRIC										
37	DEMAND	42,781	22,232	1,104	8,854	3,601	3,627	241	39,659	1,060	1,862
38	CUSTOMER	25,739	19,624	2,293	2,314	259	229	944	25,663	76	0
39	ENERGY	2,419	1,151	64	597	266	307	33	2,418	1	0
40	TOTAL ELECTRIC GENERAL PLANT	70,939	43,007	3,461	11,765	4,126	4,363	1,216	67,940	1,137	1,862
41	TOTAL ELECTRIC DEPR. RESERVE	1,398,044	725,208	41,095	240,957	94,574	98,249	43,236	1,243,319	24,730	129,995
42	DEMAND	1,137,193	549,439	27,367	219,182	88,656	91,627	6,280	982,571	24,627	129,995
43	CUSTOMER	211,106	152,104	12,398	9,489	448	298	36,266	211,004	102	0
44	ENERGY	49,745	23,665	1,310	12,286	5,470	6,323	690	49,744	1	0

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12/13 DEMAND ALLOCATION - WITH MDS METHODOLOGY
ANALYSIS OF ACCUMULATED DEPRECIATION RESERVE

Line No.	Ftnt Label	Description
1	(A)	Retail jurisdiction sum of Lines 2 and 3; Wholesale allocated per Level 1 Demand Allocator; UPS directly assigned.
2	(B)	Allocated per corresponding Level 1 Demand Allocator.
3	(C)	Allocated per corresponding Level 1 Energy Allocator.
4	(D)	Allocated per Transmission Account 350 Gross Plant (Lines portion only); UPS directly assigned.
5	(E)	Allocated per corresponding Transmission Gross Plant; UPS directly assigned.
6	(E)	
7	(E)	
8	(E)	
9	(E)	
10	(E)	
11	(E)	
13	(F)	Allocated per corresponding Distribution Gross Plant.
14	(F)	
15	(F)	
16	(F)	
17	(F)	
19	(F)	
20	(F)	
22	(F)	
23	(F)	
25	(F)	
26	(F)	
28	(F)	
29	(F)	
31	(F)	
32	(F)	
33	(F)	
37	(G)	Allocated per corresponding Gross General Plant; UPS directly assigned.
38	(G)	
39	(G)	

GULF POWER COMPANY
12 MONTHS ENDING DECEMBER 31, 2014
12/13 DEMAND ALLOCATION - WITH MDS METHODOLOGY
SCHEDULE 2.30 - ANALYSIS OF MATERIALS AND SUPPLIES
($000'S)

LINE NO. (1)	DESCRIPTION (2)	TOTAL ELECTRIC SYSTEM (3)	RATE CLASS RESIDENTIAL (4)	RATE CLASS GS (5)	RATE CLASS GSD/GSDT (6)	RATE CLASS LP/LPT (7)	RATE CLASS MAJOR ACCTS (8)	RATE CLASS OS (9)	TOTAL RETAIL SERVICE (10)	WHOLESALE (11)	UNIT POWER SALES (12)
	PRODUCTION										
1	NON-FUEL	30,413	14,766	726	5,943	2,539	3,074	135	27,183	900	2,330
	RETAIL JURISDICTION										
2	DEMAND		13,768	671	5,427	2,309	2,611	106	25,092		
3	ENERGY		998	55	516	230	283	29	2,091		
4	FUEL	103,229	44,350	2,454	23,026	10,250	11,851	1,294	93,225	2,801	7,203
5	TOTAL PRODUCTION M & S	133,642	59,116	3,180	28,969	12,789	14,925	1,429	120,408	3,701	9,533
	TRANSMISSION										
6	LINES RELATED	2,495	1,328	65	524	223	271	10	2,421	74	0
7	SUBSTATION RELATED	1,687	922	45	363	149	163	7	1,649	38	0
8	TOTAL TRANS. M & S	4,182	2,250	110	887	372	434	17	4,070	112	0
	DISTRIBUTION										
9	DEMAND RELATED	15,483.200	9,033	488	3,776	1,371	583	232	15,483	0	0
10	METERING RELATED	166.000	127	16	22	1	0	0	166	0	0
11	ST. LIGHTING RELATED	634.771	0	0	0	0	0	635	635	0	0
12	OTHER	240.421	140	7	57	21	11	3	239	1	0
13	TOTAL DIST. M & S	16,525	9,301	511	3,855	1,393	594	870	16,524	1	0
14	CUSTOMER ACCOUNTS	5	5	0	0	0	0	0	5	0	0
15	CUSTOMER ASSISTANCE	5	2	0	1	2	0	0	5	0	0
16	TOTAL ELECTRIC M & S	154,358	70,673	3,801	33,712	14,556	15,953	2,316	141,011	3,814	9,533
17	DEMAND	48,228	25,192	1,276	10,147	4,073	3,839	358	44,885	1,013	2,330
18	CUSTOMER	611	134	16	23	3	0	635	611	0	0
19	ENERGY	105,320	45,348	2,509	23,542	10,480	12,114	1,323	95,316	2,801	7,203

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12/13 DEMAND ALLOCATION - WITH MDS METHODOLOGY
ANALYSIS OF MATERIALS AND SUPPLIES

Line No.	Ftnt Label	Description
1	(A)	Retail jurisdiction sum of Lines 2 and 3; Wholesale allocated per Level 1 Demand Allocator; UPS directly assigned.
2	(B)	Allocated per corresponding Level 1 Demand Allocator.
3	(C)	Allocated per corresponding Level 1 Energy Allocator.
4	(D)	Allocated per Level 1 Energy Allocator; UPS directly assigned.
6	(E)	Allocated per Level 2 Demand Allocator; UPS directly assigned.
7	(F)	Allocated per Gross Investment in Transmission Substations excluding UPS.
9	(G)	Allocated per Level 4 NCP Demand Allocator.
10	(H)	Allocated per Distribution Gross Plant in Account 370.
11	(I)	Directly assigned to Street Lighting.
12	(J)	Allocated per Demand-related Distribution Gross Plant.
14	(K)	Allocated per Customer Accounts O & M Expense.
15	(L)	Allocated per Customer Assistance O & M Energy Cost Conservation.

GULF POWER COMPANY
12 MONTHS ENDING DECEMBER 31, 2014
12/13 DEMAND ALLOCATION - WITH MDS METHODOLOGY
SCHEDULE 2.40 - ANALYSIS OF OTHER WORKING CAPITAL
($000'S)

LINE NO. (1)	DESCRIPTION (2)	TOTAL ELECTRIC SYSTEM (3)	RATE CLASS RESIDENTIAL (4)	RATE CLASS GS (5)	RATE CLASS GSD/GSDT (6)	RATE CLASS LP/LPT (7)	RATE CLASS MAJOR ACCTS (8)	RATE CLASS OS (9)	TOTAL RETAIL SERVICE (10)	WHOLESALE (11)	UNIT POWER SALES (12)
	OTHER WORKING CAPITAL										
1	CURRENT ASSETS & LIAB.	(7,220)	(4,280)	(308)	(1,181)	(565)	(444)	(140)	(6,916)	(126)	(174)
2	DEMAND	(4,624)	(2,425)	(121)	(986)	(392)	(411)	(27)	(4,342)	(108)	(174)
3	CUSTOMER	(2,303)	(1,676)	(176)	(166)	(155)	(14)	(109)	(2,296)	(7)	0
4	ENERGY	(113)	(51)	(2)	(30)	(13)	(15)	(2)	(113)	0	0
5	REVENUE RELATED	(180)	(126)	(9)	(19)	(5)	(4)	(2)	(167)	(13)	0
6	CABLE ATTACHMENTS	(2,327)	(1,380)	(100)	(380)	(182)	(142)	(46)	(2,230)	(41)	(56)
7	DEMAND	(1,490)	(782)	(39)	(311)	(126)	(132)	(9)	(1,399)	(35)	(56)
8	CUSTOMER	(742)	(540)	(57)	(54)	(60)	(4)	(35)	(740)	(2)	0
9	ENERGY	(36)	(16)	(1)	(9)	(4)	(5)	(1)	(36)	0	0
10	REVENUE RELATED	(58)	(42)	(3)	(6)	(2)	(1)	(1)	(55)	(4)	0
	PREPAYMENTS										
11	PRODUCTION	7,233	3,682	181	1,483	633	768	33	6,780	208	245
	RETAIL JURISDICTION										
12	DEMAND		3,434	167	1,354	576	701	26	6,258		
13	ENERGY		248	14	129	57	67	7	522		
14	TRANSMISSION	2,680	1,439	70	568	239	280	11	2,607	73	0
15	DISTRIBUTION	6,567	4,138	272	1,114	388	204	449	6,543	24	0
16	DEMAND	4,208	2,441	126	1,000	382	209	49	4,183	23	0
17	CUSTOMER	2,361	1,697	144	114	4	1	400	2,360	1	0
18	CUSTOMER ACCOUNTS	124	108	8	5	0	0	2	123	1	0
19	CUSTOMER ASSSISTANCE	130	58	12	15	43	2	0	130	0	0
20	CUSTOMER	130	58	12	15	43	2	0	130	0	0
21	ENERGY	0	0	0	0	0	0	0	0	0	0
22	TOTAL PREPAYMENTS	16,734	9,425	543	3,185	1,281	1,254	495	16,183	306	245
23	DEMAND	13,597	7,314	365	2,922	1,177	1,184	86	13,048	304	245
24	CUSTOMER	2,615	1,863	164	134	47	3	402	2,813	2	0
25	ENERGY	522	248	14	129	57	67	7	522	0	0
26	PRELIM. SURVEY & INVESTIGATION	5,238	2,760	135	1,112	475	575	25	5,082	156	0
	RETAIL JURISDICTION										
27	DEMAND		2,574	125	1,015	432	525	20	4,691		
28	ENERGY		186	10	97	43	50	5	391		
	OTHER INVESTMENTS										
29	PRODUCTION	34,471	18,162	892	7,313	3,124	3,787	165	33,443	1,028	0
	RETAIL JURISDICTION										
30	DEMAND		16,939	825	6,677	2,841	3,459	129	30,870		
31	ENERGY		1,223	67	636	283	328	36	2,573		
32	TRANSMISSION	3,015	1,610	77	634	270	324	12	2,927	88	0
33	DISTRIBUTION	16,142	10,917	726	2,473	731	293	987	16,127	15	0
34	DEMAND	8,610	5,097	272	2,107	719	288	115	8,598	12	0
35	CUSTOMER	7,532	5,819	454	366	12	8	872	7,529	3	0

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GULF POWER COMPANY
12 MONTHS ENDING DECEMBER 31, 2014
12/13 DEMAND ALLOCATION - WITH MDS METHODOLOGY
SCHEDULE 2.40 - ANALYSIS OF OTHER WORKING CAPITAL
($000'S)

LINE NO. (1)	DESCRIPTION (2)	TOTAL ELECTRIC SYSTEM (3)	RATE CLASS RESIDENTIAL (4)	RATE CLASS GS (5)	RATE CLASS GSD/GSDT (6)	RATE CLASS LP/LPT (7)	RATE CLASS MAJOR ACCTS (8)	RATE CLASS OS (9)	TOTAL RETAIL SERVICE (10)	WHOLESALE (11)	UNIT POWER SALES (12)
36	CUSTOMER ACCOUNTS	9,660	8,406	635	382	10	17	132	9,582	78	0
37	CUSTOMER ASSISTANCE	10,185	6,649	1,349	1,713	253	221	0	10,185	0	0
38	CUSTOMER	10,185	6,649	1,349	1,713	253	221	0	10,185	0	0
39	ENERGY	0	0	0	0	0	0	0	0	0	0
40	TOTAL OTHER INVESTMENTS	73,473	45,743	3,679	12,515	4,388	4,643	1,296	72,264	1,209	0
41	DEMAND	43,523	23,646	1,174	9,418	3,830	4,071	256	42,395	1,128	0
42	CUSTOMER	27,377	20,874	2,438	2,481	275	244	1,004	27,296	81	0
43	ENERGY	2,573	1,223	67	636	283	328	36	2,573	0	0
44	ENVIRONMENTAL CLEANUP	58,878	34,878	2,517	9,633	4,813	3,635	1,136	56,414	1,047	1,417
45	DEMAND	37,709	19,773	984	7,880	3,198	3,356	216	35,407	885	1,417
46	CUSTOMER	18,777	13,669	1,437	1,356	1,266	116	888	18,722	55	0
47	ENERGY	924	410	20	243	109	128	14	924	0	0
48	REVENUE RELATED	1,469	1,036	76	154	42	35	18	1,361	107	0
49	PROP. INSURANCE RESERVE	(16,782)	(8,857)	(523)	(3,023)	(1,168)	(1,154)	(408)	(15,133)	(276)	(1,373)
50	DEMAND	(14,026)	(6,953)	(348)	(2,780)	(1,116)	(1,098)	(84)	(12,379)	(274)	(1,373)
51	CUSTOMER	(2,355)	(1,714)	(164)	(144)	(6)	(5)	(318)	(2,353)	(2)	0
52	ENERGY	(401)	(190)	(11)	(99)	(44)	(51)	(6)	(401)	0	0
	OTHER POST RETIREMENT BENEFITS										
53	PRODUCTION	(33,276)	(17,534)	(662)	(7,059)	(3,016)	(3,655)	(159)	(32,285)	(991)	0
	RETAIL JURISDICTION										
54	DEMAND		(16,353)	(797)	(8,446)	(2,743)	(3,336)	(125)	(29,802)		
55	ENERGY		(1,181)	(65)	(613)	(273)	(317)	(34)	(2,483)		
56	TRANSMISSION	(2,911)	(1,553)	(75)	(612)	(261)	(314)	(11)	(2,826)	(85)	0
57	DISTRIBUTION	(15,582)	(10,539)	(701)	(2,387)	(708)	(283)	(962)	(15,568)	(14)	0
58	DEMAND	(8,311)	(4,922)	(282)	(2,094)	(694)	(277)	(111)	(8,300)	(11)	0
59	CUSTOMER	(7,271)	(5,619)	(436)	(353)	(11)	(6)	(841)	(7,268)	(3)	0
60	CUSTOMER ACCOUNTS	(9,325)	(8,113)	(613)	(389)	(10)	(16)	(128)	(9,249)	(76)	0
61	CUSTOMER ASSISTANCE	(9,831)	(6,415)	(1,303)	(1,654)	(245)	(214)	0	(9,831)	0	0
62	CUSTOMER	(9,831)	(8,415)	(1,303)	(1,654)	(245)	(214)	0	(9,831)	0	0
63	ENERGY	0	0	0	0	0	0	0	0	0	0
64	TOTAL OTHER POST RETIREMENT BENEFITS	(70,925)	(44,156)	(3,563)	(12,081)	(4,237)	(4,482)	(1,250)	(69,759)	(1,166)	0
65	DEMAND	(42,015)	(22,826)	(1,134)	(9,092)	(3,698)	(3,929)	(247)	(40,926)	(1,087)	0
66	CUSTOMER	(26,427)	(20,147)	(2,354)	(2,376)	(266)	(236)	(969)	(26,348)	(79)	0
67	ENERGY	(2,483)	(1,161)	(65)	(613)	(273)	(317)	(34)	(2,483)	0	0
68	OTHER DEF. CR. & DEBITS	(44,453)	(26,331)	(1,900)	(7,272)	(3,483)	(2,745)	(661)	(42,592)	(791)	(1,070)
69	DEMAND	(28,470)	(14,928)	(743)	(5,949)	(2,413)	(2,534)	(165)	(26,732)	(668)	(1,070)
70	CUSTOMER	(14,177)	(10,311)	(1,085)	(1,024)	(956)	(68)	(671)	(14,135)	(42)	0
71	ENERGY	(697)	(309)	(15)	(183)	(83)	(96)	(11)	(697)	0	0
72	REVENUE RELATED	(1,109)	(783)	(57)	(116)	(31)	(27)	(14)	(1,028)	(81)	0
	UNAMORT. RATE CASE EXP.										
73	REVENUE RELATED	0	0	0	0	0	0	0	0	0	0
74	TOTAL OTHER WORK. CAP.	12,616	7,602	490	2,508	1,122	1,140	249	13,311	316	(1,011)
75	DEMAND	9,051	5,391	263	2,137	880	1,032	48	9,761	301	(1,011)
76	CUSTOMER	2,765	2,008	203	187	153	16	192	2,759	6	0
77	ENERGY	680	320	17	171	75	89	8	680	0	0
78	REVENUE RELATED	120	83	7	13	4	3	1	111	9	0

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12 MONTHS ENDED DECEMBER 31, 2014
12/13 DEMAND ALLOCATION - WITH MDS METHODOLOGY
ANALYSIS OF OTHER WORKING CAPITAL

Line No.	Ftnt Label	Description
1	(A)	Allocated per Total Expenses less Production Energy related O & M, Income taxes, and Non-cash items.
2	(A)	
3	(A)	
4	(A)	
5	(A)	
6	(A)	
7	(A)	
8	(A)	
9	(A)	
10	(A)	
11	(B)	Allocated per corresponding Gross Plant; UPS directly assigned.
12	(C)	Allocated per corresponding Gross Plant.
13	(C)	
14	(B)	
15	(C)	
16	(C)	
17	(C)	
18	(D)	Allocated per corresponding Operations and Maintenance Expense.
19	(D)	
20	(D)	
21	(D)	
26	(E)	Allocated per Production Gross Plant; UPS directly assigned.
27	(F)	Allocated per corresponding Production Gross Plant.
28	(F)	
29	(G)	Allocated per corresponding Salaries and Wages
30	(G)	
31	(G)	
32	(G)	
33	(G)	
34	(G)	
35	(G)	
36	(G)	
37	(G)	
38	(G)	
39	(G)	

GULF POWER COMPANY
12 MONTHS ENDED DECEMBER 31, 2014
12/13 DEMAND ALLOCATION - WITH MDS METHODOLOGY
ANALYSIS OF OTHER WORKING CAPITAL

Line No.	Ftnt Label	Description
44	(A)	
45	(A)	
46	(A)	
47	(A)	
48	(A)	
49	(H)	Allocated per Total Net Plant; UPS directly assigned.
50	(H)	
51	(I)	Allocated per Total Net Plant.
52	(I)	
53	(G)	
54	(G)	
55	(G)	
56	(G)	
57	(G)	
58	(G)	
59	(G)	
60	(G)	
61	(G)	
62	(G)	
63	(G)	
68	(A)	
69	(A)	
70	(A)	
71	(A)	
72	(A)	
73	(J)	Allocated per Retail Revenue from Sales.

GULF POWER COMPANY
12 MONTHS ENDING DECEMBER 31, 2014
12/13 DEMAND ALLOCATION - WITH MDS METHODOLOGY
SCHEDULE 2.50 - ANALYSIS OF OTHER RATE BASE ITEMS
($000'S)

LINE NO. (1)	DESCRIPTION (2)	TOTAL ELECTRIC SYSTEM (3)	RATE CLASS RESIDENTIAL (4)	RATE CLASS GS (5)	RATE CLASS GSD/GSDT (6)	RATE CLASS LP/LPT (7)	RATE CLASS MAJOR ACCTS (8)	RATE CLASS OS (9)	TOTAL RETAIL SERVICE (10)	WHOLESALE (11)	UNIT POWER SALES (12)
	CONST. WORK IN PROGRESS INTEREST BEARING										
1	PRODUCTION	0	0	0	0	0	0	0	0	0	0
	RETAIL JURISDICTION										
2	DEMAND		0	0	0	0	0	0	0		
3	ENERGY		0	0	0	0	0	0	0		
4	TRANSMISSION	0	0	0	0	0	0	0	0	0	0
5	DISTRIBUTION	0	0	0	0	0	0	0	0	0	0
6	DEMAND	0	0	0	0	0	0	0	0	0	0
7	CUSTOMER	0	0	0	0	0	0	0	0	0	0
8	CUSTOMER ACCOUNTS	0	0	0	0	0	0	0	0	0	0
9	CUSTOMER ASSISTANCE	0	0	0	0	0	0	0	0	0	0
10	CUSTOMER	0	0	0	0	0	0	0	0	0	0
11	ENERGY	0	0	0	0	0	0	0	0	0	0
12	TOTAL CWIP	0	0	0	0	0	0	0	0	0	0
13	DEMAND	0	0	0	0	0	0	0	0	0	0
14	CUSTOMER	0	0	0	0	0	0	0	0	0	0
15	ENERGY	0	0	0	0	0	0	0	0	0	0
	CONST. WORK IN PROGRESS WORK NOT BEARING INTEREST										
16	PRODUCTION	17,325	5,673	279	2,295	976	1,182	52	10,447	321	6,557
	RETAIL JURISDICTION										
17	DEMAND		5,290	258	2,096	888	1,080	41	9,643		
18	ENERGY		383	21	199	88	102	11	804		
19	TRANSMISSION	10,704	5,753	280	2,267	953	1,115	44	10,412	292	0
20	DISTRIBUTION	5,818	3,884	240	991	326	182	394	5,797	21	0
21	DEMAND	3,747	2,174	114	991	323	181	43	3,726	21	0
22	CUSTOMER	2,071	1,490	126	100	3	1	351	2,071	0	0
23	TOTAL CWIP - WORK NOT BEARING INTEREST	33,847	15,090	799	5,543	2,255	2,479	490	26,656	634	6,557
24	DEMAND	30,972	13,217	652	5,244	2,164	2,376	129	23,781	634	6,557
25	CUSTOMER	2,071	1,490	126	100	3	1	351	2,071	0	0
26	ENERGY	804	383	21	199	88	102	11	804	0	0
	PLANT HELD FOR FUTURE USE										
27	PRODUCTION	5,280	2,785	136	1,120	478	579	25	5,123	157	0
	RETAIL JURISDICTION										
28	DEMAND		2,596	126	1,023	436	529	20	4,729		
29	ENERGY		189	10	97	43	50	5	394		
	DISTRIBUTION										
30	DEMAND	14	9	0	3	1	1	0	14	0	0
31	CUSTOMER	8	5	1	1	0	0	1	8	0	0
32	TOTAL DISTRIBUTION	22	14	1	4	1	1	1	22	0	0
	GENERAL										
33	DEMAND	79	44	2	17	7	7	0	77	2	0
34	CUSTOMER	50	38	4	5	1	0	2	50	0	0
35	ENERGY	4	2	1	0	0	1	0	4	0	0
36	TOTAL GENERAL	133	84	7	22	8	8	2	131	2	0
37	TOTAL PLNT HELD FOR FUT. USE	5,435	2,883	144	1,146	487	588	28	5,276	159	0
38	DEMAND	4,979	2,649	128	1,043	443	537	20	4,820	159	0
39	CUSTOMER	58	43	5	6	1	0	3	58	0	0
40	ENERGY	398	191	11	97	43	51	5	398	0	0

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GULF POWER COMPANY
12 MONTHS ENDING DECEMBER 31, 2014
12/13 DEMAND ALLOCATION - WITH MDS METHODOLOGY
SCHEDULE 2.50 - ANALYSIS OF OTHER RATE BASE ITEMS
($000'S)

LINE NO. (1)	DESCRIPTION (2)	TOTAL ELECTRIC SYSTEM (3)	RATE CLASS RESIDENTIAL (4)	RATE CLASS GS (5)	RATE CLASS GSD/GSDT (6)	RATE CLASS LP/LPT (7)	RATE CLASS MAJOR ACCTS (8)	RATE CLASS OS (9)	TOTAL RETAIL SERVICE (10)	WHOLESALE (11)	UNIT POWER SALES (12)
	INJURIES & DAMAGES RESERVE										
41	PRODUCTION	(1,626)	(804)	(40)	(324)	(139)	(167)	(8)	(1,482)	(46)	(98)
	RETAIL JURISDICTION										
42	DEMAND		(750)	(37)	(298)	(126)	(153)	(6)	(1,368)		
43	ENERGY		(54)	(3)	(28)	(13)	(14)	(2)	(114)		
44	TRANSMISSION	(134)	(72)	(3)	(28)	(12)	(14)	(1)	(130)	(4)	0
45	DISTRIBUTION	(715)	(483)	(32)	(110)	(32)	(13)	(44)	(714)	(1)	0
46	DEMAND	(381)	(225)	(12)	(93)	(32)	(13)	(5)	(380)	(1)	0
47	CUSTOMER	(334)	(258)	(20)	(17)	0	0	(39)	(334)	0	0
48	CUSTOMER ACCOUNTS	(428)	(374)	(28)	(17)	0	0	(6)	(425)	(3)	0
49	CUSTOMER ASSISTANCE	(451)	(294)	(60)	(76)	(11)	(10)	0	(451)	0	0
50	CUSTOMER	(451)	(294)	(60)	(76)	(11)	(10)	0	(451)	0	0
51	ENERGY	0	0	0	0	0	0	0	0	0	0
52	TOTAL INJ. & DAM. RES.	(3,354)	(2,027)	(163)	(555)	(194)	(204)	(59)	(3,202)	(54)	(98)
53	DEMAND	(2,027)	(1,047)	(52)	(417)	(170)	(180)	(12)	(1,878)	(51)	(98)
54	CUSTOMER	(1,213)	(926)	(108)	(110)	(11)	(10)	(45)	(1,210)	(3)	0
55	ENERGY	(114)	(54)	(3)	(28)	(13)	(14)	(2)	(114)	0	0
	UNAMORT. PLANT ACQ. ADJ.										
56	PRODUCTION	1,852	0	0	0	0	0	0	0	0	1,852
	RETAIL JURISDICTION										
57	DEMAND		0	0	0	0	0	0	0		
58	ENERGY		0	0	0	0	0	0	0		
59	TRANSMISSION	51	0	0	0	0	0	0	0	0	51
60	DISTRIBUTION	0	0	0	0	0	0	0	0	0	0
61	DEMAND	0	0	0	0	0	0	0	0	0	0
62	CUSTOMER	0	0	0	0	0	0	0	0	0	0
63	TOTAL UNAMORT PLNT ACQ. ADJ.	1,903	0	0	0	0	0	0	0	0	1,903
64	DEMAND	1,903	0	0	0	0	0	0	0	0	1,903
65	CUSTOMER	0	0	0	0	0	0	0	0	0	0
66	ENERGY	0	0	0	0	0	0	0	0	0	0
67	CUSTOMER ADVANCES FOR CONST.	0	0	0	0	0	0	0	0	0	0
68	TOTAL OTHER ADDITIONS	37,631	15,946	780	8,134	2,548	2,863	459	26,730	739	8,362
69	DEMAND	35,627	14,619	728	5,870	2,437	2,733	136	26,723	742	8,362
70	CUSTOMER	916	607	23	(4)	(7)	(9)	309	919	(3)	0
71	ENERGY	1,088	520	29	268	116	139	14	1,088	0	0

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GULF POWER COMPANY
12 MONTHS ENDED DECEMBER 31, 2014
12/13 DEMAND ALLOCATION - WITH MDS METHODOLOGY
ANALYSIS OF OTHER RATE BASE ITEMS

Line No.	Ftnt Label	Description
1	(A)	Functional totals provided by Gulf Power Company. Allocated per corresponding Gross Plant excluding UPS; UPS directly assigned.
2	(B)	Functional totals provided by Gulf Power Company. Allocated per corresponding Gross Plant.
3	(B)	
4	(B)	
5	(B)	
6	(B)	
7	(B)	
8	(C)	Allocated per corresponding Operations and Maintenance expense.
9	(C)	
10	(C)	
11	(C)	
16	(A)	
17	(B)	
18	(B)	
19	(B)	
20	(B)	
21	(B)	
22	(B)	
27	(B)	
28	(B)	
29	(B)	
30	(B)	
31	(B)	
33	(B)	
34	(B)	
35	(B)	
41	(D)	Allocated per Total Salaries and Wages, including UPS Production Salaries and Wages of $2,434.
42	(E)	Allocated per corresponding Salaries and Wages.
43	(E)	
44	(D)	
45	(E)	
46	(E)	
47	(E)	
48	(E)	
49	(E)	
50	(E)	
51	(E)	
56	(A)	
57	(B)	
58	(B)	
59	(A)	
60	(B)	
61	(B)	
62	(B)	
67	(F)	Specific Assignment.

GULF POWER COMPANY
12 MONTHS ENDING DECEMBER 31, 2014
12/13 DEMAND ALLOCATION - WITH MDS METHODOLOGY
SCHEDULE 3.00 - ANALYSIS OF REVENUES
($000'S)

LINE NO. (1)	DESCRIPTION (2)	TOTAL ELECTRIC SYSTEM (3)	RATE CLASS RESIDENTIAL (4)	RATE CLASS GS (5)	RATE CLASS GSD/GSDT (6)	RATE CLASS LP/LPT (7)	RATE CLASS MAJOR ACCTS (8)	RATE CLASS OS (9)	TOTAL RETAIL SERVICE (10)	WHOLESALE (11)	UNIT POWER SALES (12)
	REVENUE FROM SALES										
1	BASE RATE REV. FROM SALES	510,734	296,890	20,537	102,785	33,933	29,452	14,896	498,493	12,241	0
2	FUEL, ECCR, PPCC, ECRC REVENUES	0	0	0	0	0	0	0	0	0	0
3	NET REVENUE EXCLUDING FUEL	510,734	296,890	20,537	102,785	33,933	29,452	14,896	498,493	12,241	0
	OTHER OPERATING REVENUES										
	451-MISC. SERVICE REVENUES										
4	RESTORATION FEE	1,213	1,174	31	6	0	0	0	1,213	0	0
5	AFTER HOURS FEE	116	115	1	0	0	0	0	116	0	0
6	INACCURATE METER FEE	26	19	2	5	0	0	0	26	0	0
7	RECONNECTION FEE	2,823	2,696	84	43	0	0	0	2,823	0	0
8	FRANCHISE FEES	42,247	25,162	1,740	6,711	2,876	2,496	1,262	42,247	0	0
9	INSTALL. & REM.-TEMP SERV	0	0	0	0	0	0	0	0	0	0
10	CONNECTION FEES	92	77	13	2	0	0	0	92	0	0
11	COLLECTION CHARGES	207	161	24	22	0	0	0	207	0	0
12	INVESTIGATIVE CHARGES	40	38	2	0	0	0	0	40	0	0
13	RETURN CHECK CHARGE	272	258	6	6	0	0	0	272	0	0
14	TOTAL ACCOUNT 451	47,036	29,700	1,903	6,799	2,876	2,496	1,262	47,036	0	0
	454-RENT FROM ELEC. PROP.										
15	EQUIPMENT RENTAL	1,686	1,045	57	435	119	3	27	1,686	0	0
16	METER TREATER RENTAL	253	244	7	2	0	0	0	253	0	0
17	POLE ATTACHMENT RENTAL	3,110	2,411	169	343	91	32	64	3,110	0	0
18	MICROWAVE TRANSPORT	730	453	37	124	44	47	13	716	12	0
19	RENT FROM PLANT DANIEL	40	22	1	6	4	4	0	39	1	0
20	MISCELLANEOUS RENTS	516	321	26	88	31	33	9	508	6	0
21	TOTAL ACCOUNT 454	6,335	4,496	297	1,000	289	119	113	6,314	21	0
22	455-INTERDEPART. RENTAL	0	0	0	0	0	0	0	0	0	0
23	456-OTHER ELECTRIC REVENUES	6,368	3,390	165	1,336	569	692	26	6,178	190	0
24	456-GULF POWER ENERGY SERVICES REVENUES	5,632	0	0	0	5,632	0	0	5,632	0	0
25	456 - FPU SERVICE PAYMENTS	3,678	0	0	0	0	0	0	0	3,678	0
26	456 - BLOUNTSTOWN SERVICE PAYMENTS	122	65	3	26	11	13	0	116	4	0
27	TOTAL ACCOUNT 456	15,800	3,456	168	1,362	6,212	705	26	11,928	3,872	0
28	REV. NONASSOC. CO.-DEMAND	51,950	0	0	0	0	0	0	0	0	51,950
29	REV. NONASSOC. CO.-ENERGY	13,652	3,389	188	1,760	784	907	99	7,127	214	6,311
30	TOTAL REV. NONASSOC. CO.	65,602	3,389	188	1,760	784	907	99	7,127	214	58,261
31	TOTAL OTHER OPER. REVENUE	134,773	41,040	2,556	12,921	10,161	4,227	1,500	72,405	4,107	58,261
	ADJUSTMENTS TO REVENUES										
32	FRANCHISE FEE REVENUES	(42,247)	(25,162)	(1,740)	(6,711)	(2,876)	(2,496)	(1,262)	(42,247)	(0)	0
33	NET ADJUSTMENT TO REVENUES	(42,247)	(25,162)	(1,740)	(6,711)	(2,876)	(2,496)	(1,262)	(42,247)	(0)	0
34	TOTAL ADJUSTED REVENUES	603,260	312,768	21,353	106,995	41,216	31,183	15,134	528,651	16,348	58,261

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12 MONTHS ENDED DECEMBER 31, 2014
12/13 DEMAND ALLOCATION - WITH MDS METHODOLOGY
ANALYSIS OF REVENUES

Line No.	Ftnt Label	Description
1	(A)	Provided by Gulf Power Company.
2	(B)	Allocated per Retail MWH Sales.
4	(A)	
5	(A)	
6	(A)	
7	(A)	
8	(C)	Allocated per retail revenue from sales.
9	(A)	
10	(A)	
11	(A)	
12	(A)	
13	(A)	
15	(D)	Allocated per Level 5 Demand Allocator
16	(A)	
17	(E)	Allocated per Distribution Gross Plant in Account 364.
18	(F)	Allocated per Total Salaries and Wages.
19	(G)	Allocated per Level 2 Demand Allocator; UPS directly assigned.
20	(F)	
22	(F)	
23	(G)	
24	(H)	Provided by Gulf Power Company and assigned to Rate Class LP/LPT.
25	(I)	Assigned to FPU.
26	(G)	
28	(G)	
29	(J)	Allocated per Level 1 Energy Allocator; UPS directly assigned.
32	(C)	

GULF POWER COMPANY
12 MONTHS ENDING DECEMBER 31, 2014
12/13 DEMAND ALLOCATION - WITH MDS METHODOLOGY
SCHEDULE 4.10 - ANALYSIS OF OPERATIONS AND MAINTENANCE EXPENSE
($000'S)

LINE NO. (1)	DESCRIPTION (2)	TOTAL ELECTRIC SYSTEM (3)	RATE CLASS RESIDENTIAL (4)	RATE CLASS GS (5)	RATE CLASS GSD/GSDT (6)	RATE CLASS LP/LPT (7)	RATE CLASS MAJOR ACCTS (8)	RATE CLASS OS (9)	TOTAL RETAIL SERVICE (10)	WHOLESALE (11)	UNIT POWER SALES (12)
	PRODUCTION O & M EXPENSES										
	STEAM POWER GENERATION										
	OPERATIONS										
1	500-SUPERVISION	11,719	6,087	297	2,400	1,021	1,244	47	11,096	341	282
2	501-ENERGY RELATED	310,081	127,134	7,034	66,006	29,382	33,974	3,709	267,239	8,028	34,814
3	501-FUEL REMOVAL	(303,538)	(124,330)	(6,879)	(64,550)	(28,734)	(33,224)	(3,627)	(261,344)	(7,851)	(34,343)
4	501-NET	6,543	2,804	155	1,456	648	750	82	5,895	177	471
	502-STEAM										
5	DEMAND RELATED	2,508	1,171	57	462	197	240	9	2,136	66	306
6	ENERGY RELATED	5,763	2,193	121	1,139	507	586	64	4,610	139	1,014
7	TOTAL ACCOUNT 502	8,271	3,364	178	1,601	704	826	73	6,746	205	1,320
	505-ELECTRIC EXPENSES										
8	DEMAND RELATED	2,946	1,472	72	580	247	301	11	2,683	82	181
9	ENERGY RELATED	1,185	533	30	278	124	143	16	1,124	34	27
10	TOTAL ACCOUNT 505	4,131	2,005	102	858	371	444	27	3,807	116	208
	506-MISCELLANEOUS										
11	DEMAND RELATED	15,224	7,666	374	3,022	1,286	1,585	59	13,972	429	823
12	ENERGY RELATED	0	0	0	0	0	0	0	0	0	0
13	TOTAL ACCOUNT 506	15,224	7,666	374	3,022	1,286	1,585	59	13,972	429	823
14	507-RENTS	0	0	0	0	0	0	0	0	0	0
15	509-ALLOWANCES	0	0	0	0	0	0	0	0	0	0
16	TOTAL STEAM OPERATIONS	45,888	21,926	1,106	9,337	4,030	4,829	288	41,516	1,288	3,104
	MAINTENANCE										
17	510-SUPERVISION	9,666	4,915	240	1,938	825	1,004	38	8,960	275	651
18	511-STRUCTURES	5,707	2,864	139	1,128	480	594	22	5,217	160	330
	512-BOILER PLANT										
19	DEMAND RELATED	3,490	1,577	77	622	265	322	12	2,875	88	527
20	ENERGY RELATED	25,255	9,588	531	4,979	2,216	2,562	280	20,166	606	4,493
21	TOTAL ACCOUNT 512	28,745	11,165	608	5,601	2,481	2,884	292	23,031	694	5,020
	513-ELECTRIC PLANT										
22	DEMAND RELATED	1,340	701	34	276	118	144	5	1,278	39	23
23	ENERGY RELATED	7,097	2,962	164	1,538	684	791	86	6,225	187	685
24	TOTAL ACCOUNT 513	8,437	3,663	198	1,814	802	935	91	7,503	226	708

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12/13 DEMAND ALLOCATION - WITH MDS METHODOLOGY
SCHEDULE 4.10 - ANALYSIS OF OPERATIONS AND MAINTENANCE EXPENSE
($000'S)

LINE NO. (1)	DESCRIPTION (2)	TOTAL ELECTRIC SYSTEM (3)	RATE CLASS RESIDENTIAL (4)	RATE CLASS GS (5)	RATE CLASS GSD/GSDT (6)	RATE CLASS LP/LPT (7)	RATE CLASS MAJOR ACCTS (8)	RATE CLASS OS (9)	TOTAL RETAIL SERVICE (10)	WHOLESALE (11)	UNIT POWER SALES (12)
	514-MISCELLANEOUS										
25	DEMAND RELATED	3,132	1,529	75	603	257	312	12	2,788	86	258
26	ENERGY RELATED	0	0	0	0	0	0	0	0	0	0
27	TOTAL ACCOUNT 514	3,132	1,529	75	603	257	312	12	2,788	86	258
28	TOTAL MAINTENANCE	55,907	24,136	1,260	11,084	4,845	5,719	455	47,499	1,441	6,967
29	TOTAL STEAM POWER GENERATION	101,795	46,062	2,366	20,421	8,675	10,548	743	89,015	2,709	10,071
	OTHER POWER GENERATION										
	OPERATION										
30	546-SUPERVISION	1,701	905	44	357	152	185	7	1,650	51	0
31	547-ENERGY RELATED	580	267	15	139	62	72	8	563	17	0
32	547-FUEL	310,241	143,267	7,928	74,392	33,115	38,291	4,180	301,193	9,048	0
33	547-FUEL REMOVAL	(310,241)	(143,267)	(7,928)	(74,392)	(33,115)	(38,291)	(4,180)	(301,193)	(9,048)	0
34	547-NET FUEL	0	0	0	0	0	0	0	0	0	0
	548-GENERATION EXPENSES										
35	DEMAND	528	281	14	111	47	57	2	512	16	0
36	ENERGY	0	0	0	0	0	0	0	0	0	0
37	TOTAL ACCOUNT 548	528	281	14	111	47	57	2	512	16	0
	549-MISCELLANEOUS PLANT										
38	DEMAND	848	452	22	178	76	92	3	823	25	0
39	ENERGY	0	0	0	0	0	0	0	0	0	0
40	TOTAL ACCOUNT 549	848	452	22	178	76	92	3	823	25	0
41	TOTAL OPERATION	3,657	1,905	95	795	337	406	20	3,548	109	0
	MAINTENANCE										
42	551-SUPERVISION	296	157	8	62	26	33	1	287	9	0
	552-STRUCTURES										
43	DEMAND	0	0	0	0	0	0	0	0	0	0
44	ENERGY	0	0	0	0	0	0	0	0	0	0
45	TOTAL ACCOUNT 552	0	0	0	0	0	0	0	0	0	0

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SCHEDULE 4.10 - ANALYSIS OF OPERATIONS AND MAINTENANCE EXPENSE
($000'S)

LINE NO. (1)	DESCRIPTION (2)	TOTAL ELECTRIC SYSTEM (3)	RATE CLASS RESIDENTIAL (4)	RATE CLASS GS (5)	RATE CLASS GSD/GSDT (6)	RATE CLASS LP/LPT (7)	RATE CLASS MAJOR ACCTS (8)	RATE CLASS OS (9)	TOTAL RETAIL SERVICE (10)	WHOLESALE (11)	UNIT POWER SALES (12)
	553-ELECTRIC PLANT										
46	DEMAND	6,665	3,547	173	1,399	595	725	27	6,466	199	0
47	ENERGY	0	0	0	0	0	0	0	0	0	0
48	TOTAL ACCOUNT 553	6,665	3,547	173	1,399	595	725	27	6,466	199	0
	554-MISCELLANEOUS PLANT										
49	DEMAND	524	278	14	110	47	57	2	508	16	0
50	ENERGY	0	0	0	0	0	0	0	0	0	0
51	TOTAL ACCOUNT 554	524	278	14	110	47	57	2	508	16	0
52	TOTAL MAINTENANCE	7,485	3,982	195	1,571	668	815	30	7,251	224	0
53	TOTAL OTHER GEN. EXPENSE	11,142	5,887	290	2,356	1,005	1,221	50	10,809	333	0
54	TOTAL GENERATION EXPENSES	112,837	61,949	2,656	22,777	9,690	11,769	793	99,824	3,042	10,071
55	DEMAND	66,514	33,602	1,640	13,248	5,639	6,865	257	61,251	1,882	3,381
56	ENERGY	46,423	18,347	1,016	9,529	4,241	4,904	536	38,573	1,160	6,690
	OTHER PRODUCTION EXPENSE										
57	555-PURCHASED POWER	35,992	15,276	845	7,932	3,531	4,083	446	32,113	965	2,914
58	DEMAND	0	0	0	0	0	0	0	0	0	0
59	ENERGY	35,992	15,276	845	7,932	3,531	4,083	446	32,113	965	2,914
60	FUEL REMOVAL	(35,992)	(15,276)	(845)	(7,932)	(3,531)	(4,083)	(446)	(32,113)	(965)	(2,914)
61	NET ENERGY	0	0	0	0	0	0	0	0	0	0
62	NET TOTAL ACCOUNT 555	0	0	0	0	0	0	0	0	0	0
	556-SYSTEM CONTROL										
63	DEMAND	1,817	968	47	381	162	198	7	1,763	54	0
64	ENERGY	0	0	0	0	0	0	0	0	0	0
65	TOTAL ACCOUNT 556	1,817	968	47	381	162	198	7	1,763	54	0
	557-OTHER EXPENSES										
66	DEMAND	2,054	1,095	53	431	183	223	8	1,993	61	0
67	ENERGY	0	0	0	0	0	0	0	0	0	0
68	TOTAL ACCOUNT 557	2,054	1,095	53	431	183	223	8	1,993	61	0
69	TOTAL OTHER PROD. EXPENSE	3,871	2,063	100	812	345	421	15	3,756	115	0
70	DEMAND	3,871	2,063	100	812	345	421	15	3,756	115	0
71	ENERGY	0	0	0	0	0	0	0	0	0	0
72	TOTAL PRODUCTION EXPENSES	116,808	64,012	2,756	23,589	10,225	12,190	808	103,580	3,157	10,071
73	DEMAND	70,385	35,665	1,740	14,060	5,984	7,286	272	65,007	1,997	3,381
74	ENERGY	46,423	18,347	1,016	9,529	4,241	4,904	536	38,573	1,160	6,690

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SCHEDULE 4.10 - ANALYSIS OF OPERATIONS AND MAINTENANCE EXPENSE
($000'S)

LINE NO. (1)	DESCRIPTION (2)	TOTAL ELECTRIC SYSTEM (3)	RATE CLASS RESIDENTIAL (4)	RATE CLASS GS (5)	RATE CLASS GSD/GSDT (6)	RATE CLASS LP/LPT (7)	RATE CLASS MAJOR ACCTS (8)	RATE CLASS OS (9)	TOTAL RETAIL SERVICE (10)	WHOLESALE (11)	UNIT POWER SALES (12)
	TRANSMISSION O & M EXPENSE										
	OPERATION										
75	561-LOAD DISPATCHING	3,526	1,877	91	739	315	383	14	3,419	105	2
76	562-STATION	43	24	1	9	4	4	0	42	1	0
77	563-OVERHEAD LINES	191	101	5	40	17	21	1	185	6	0
78	564-UNDERGROUND LINES	0	0	0	0	0	0	0	0	0	0
79	565-TRANS. OF ELEC. BY OTHERS	(301)	(160)	(8)	(63)	(27)	(33)	(1)	(292)	(9)	0
80	SUBTOTAL	3,459	1,842	89	725	309	375	14	3,354	103	2
81	560-SUPERVISION	1,609	856	41	337	144	175	7	1,560	48	1
82	566-MISCELLANEOUS	1,038	552	27	217	93	113	4	1,006	31	1
83	567-RENTS	165	87	4	35	15	18	1	160	5	0
84	TOTAL OPERATIONS	6,271	3,337	161	1,314	561	681	26	6,080	187	4
	MAINTENANCE										
85	568-STRUCTURES	1,003	533	26	211	90	109	4	973	30	0
86	570-STATION EQUIPMENT	830	454	22	179	74	79	3	811	19	0
87	571-OVERHEAD LINES	4,479	2,385	116	940	400	486	18	4,345	134	0
88	SUBTOTAL	6,312	3,372	164	1,330	564	674	25	6,129	183	0
89	568-SUPERVISION	1,052	561	27	222	94	113	4	1,021	31	0
90	573-MISCELLANEOUS	102	56	3	21	9	10	0	99	3	0
91	TOTAL MAINTENANCE	7,466	3,989	194	1,573	667	797	29	7,249	217	0
92	TOTAL TRANSMISSION EXPENSE	13,737	7,326	355	2,887	1,228	1,478	55	13,329	404	4
	DISTRIBUTION O & M EXPENSE										
	OPERATIONS										
93	581-LOAD DISPATCHING	902	536	26	211	78	47	4	902	0	0
94	582-STATION	309	168	8	68	30	32	1	303	5	0

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($000'S)

LINE NO. (1)	DESCRIPTION (2)	TOTAL ELECTRIC SYSTEM (3)	RATE CLASS RESIDENTIAL (4)	RATE CLASS GS (5)	RATE CLASS GSD/GSDT (6)	RATE CLASS LP/LPT (7)	RATE CLASS MAJOR ACCTS (8)	RATE CLASS OS (9)	TOTAL RETAIL SERVICE (10)	WHOLESALE (11)	UNIT POWER SALES (12)
	583-OVERHEAD LINES										
95	DEMAND	2,006	1,215	66	505	158	33	31	2,006	0	0
96	CUSTOMER	573	500	37	23	0	0	13	573	0	0
97	TOTAL ACCOUNT 583	2,579	1,715	103	528	158	33	44	2,579	0	0
	584-UNDERGROUND LINES										
98	DEMAND	608	368	20	154	47	10	9	608	0	0
99	CUSTOMER	131	115	9	4	0	0	3	131	0	0
100	TOTAL ACCOUNT 584	739	483	29	158	47	10	12	739	0	0
101	585-STREET LIGHTING	598	0	0	0	0	0	598	598	0	0
102	586-METER	1,453	1,090	144	196	11	6	3	1,450	3	0
103	586-OTHER MISC. REVS.	1,174	1,116	38	18	0	0	0	1,174	0	0
104	TOTAL ACCOUNT 586	2,627	2,208	182	214	11	6	3	2,624	3	0
105	587-CUSTOMER INSTAL.	1,306	1,164	89	53	1	0	0	1,306	0	0
106	587-OTHER MISC. REVS.	25	24	1	0	0	0	0	25	0	0
107	TOTAL ACCOUNT 587	1,331	1,188	89	53	1	0	0	1,331	0	0
108	SUBTOTAL	9,084	6,296	437	1,230	323	128	662	9,076	8	0
109	DEMAND	3,824	2,295	120	936	311	122	45	3,819	5	0
110	CUSTOMER	5,260	4,011	317	294	12	6	617	5,257	3	0
	580-SUPERVISION										
111	DEMAND	2,849	1,702	89	697	232	91	34	2,845	4	0
112	CUSTOMER	3,919	2,989	236	219	9	4	460	3,917	2	0
113	TOTAL ACCOUNT 580	6,768	4,691	325	916	241	95	494	6,762	6	0
	588-MISCELLANEOUS										
114	DEMAND	1,837	1,099	58	449	149	58	22	1,835	2	0
115	CUSTOMER	2,526	1,928	152	141	6	2	296	2,525	1	0
116	TOTAL ACCOUNT 588	4,363	3,027	210	590	155	60	318	4,360	3	0
	589-RENTS										
117	DEMAND	0	0	0	0	0	0	0	0	0	0
118	CUSTOMER	0	0	0	0	0	0	0	0	0	0
119	TOTAL ACCOUNT 589	0	0	0	0	0	0	0	0	0	0
120	TOTAL OPERATION	20,215	14,014	972	2,736	719	283	1,474	20,198	17	0
	MAINTENANCE										
121	591-STRUCTURES	28	15	1	8	3	2	0	27	1	0
122	592-STATION EQUIPMENT	962	518	25	205	94	100	4	946	16	0

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123	593-OVHD LINES - MISC REVS	0	0	0	0	0	0	0	0	0	0
	593-OVERHEAD LINES										
124	DEMAND	7,747	4,582	248	1,913	655	231	118	7,747	0	0
125	CUSTOMER	5,328	4,641	350	210	3	0	124	5,328	0	0
126	SUBTOTAL OVERHEAD LINES	13,075	9,223	598	2,123	658	231	242	13,075	0	0
127	TOTAL ACCOUNT 593	13,075	9,223	598	2,123	658	231	242	13,075	0	0
	594-UNDERGROUND LINES										
128	DEMAND	1,810	1,075	58	449	151	49	28	1,810	0	0
129	CUSTOMER	87	76	8	3	0	0	2	87	0	0
130	TOTAL ACCOUNT 594	1,897	1,151	64	452	151	49	30	1,897	0	0
	595-LINE TRANSFORMERS										
131	DEMAND	747	458	25	191	55	6	12	747	0	0
132	CUSTOMER	254	222	16	10	0	0	6	254	0	0
133	TOTAL ACCOUNT 595	1,001	680	41	201	55	6	18	1,001	0	0
134	596-STREET LIGHTING	597	0	0	0	0	0	597	597	0	0
135	597-METERS	159	121	16	21	1	0	0	159	0	0
136	SUBTOTAL	17,719	11,708	745	3,008	962	388	891	17,702	17	0
137	DEMAND	11,294	6,648	357	2,764	958	388	162	11,277	17	0
138	CUSTOMER	6,425	5,060	388	244	4	0	729	6,425	0	0
	590-SUPERVISION										
139	DEMAND	2,335	1,378	74	571	198	79	33	2,331	4	0
140	CUSTOMER	1,329	1,047	80	50	1	0	151	1,329	0	0
141	TOTAL ACCOUNT 590	3,664	2,423	154	621	199	79	184	3,660	4	0
	598-MISCELLANEOUS										
142	DEMAND	301	177	10	74	28	10	4	301	0	0
143	CUSTOMER	171	136	10	6	0	0	19	171	0	0
144	TOTAL ACCOUNT 598	472	313	20	80	28	10	23	472	0	0
145	TOTAL MAINTENANCE	21,855	14,444	919	3,709	1,167	477	1,098	21,834	21	0
146	TOTAL DISTRIBUTION EXPENSE	42,070	28,458	1,891	6,445	1,906	760	2,572	42,032	38	0
147	TOTAL DEMAND	22,440	13,287	708	5,491	1,874	748	300	22,408	32	0
148	TOTAL CUSTOMER	19,630	15,171	1,183	954	32	12	2,272	19,624	6	0
149	CUSTOMER ACCOUNTS EXPENSE	21,986	19,131	1,446	869	22	38	301	21,807	179	0

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	CUSTOMER ASSISTANCE EXPENSE										
150	907/911-SUPERVISION	1,829	1,603	141	84	1	0	0	1,829	0	0
	908/912-CUSTOMER ASSISTANCE										
151	RESIDENTIAL	5,080	5,080	0	0	0	0	0	5,080	0	0
152	COMMERCIAL	2,093	0	1,305	776	11	1	0	2,093	0	0
153	TOTAL INDUSTRIAL	7,391	0	145	1,121	5,874	251	0	7,391	0	0
154	INDUSTRIAL - GULF POWER ENERGY SRVS	5,597	0	0	0	5,597	0	0	5,597	0	0
155	NET INDUSTRIAL OF GULF POWER ENERGY SRVS	1,794	0	145	1,121	277	251	0	1,794	0	0
156	STREET LIGHTING	0	0	0	0	0	0	0	0	0	0
157	TOTAL ACCOUNT 908/912	14,564	5,080	1,450	1,897	5,885	252	0	14,564	0	0
158	909/913-ADVERTISING	1,232	1,125	13	65	15	14	0	1,232	0	0
159	910-MISCELLANEOUS	190	168	15	9	0	0	0	190	0	0
160	ENERGY CONSERVATION	21,933	19,377	1,357	1,058	78	63	0	21,933	0	0
161	ECCR ADJUSTMENT	(21,933)	(19,377)	(1,357)	(1,058)	(78)	(63)	0	(21,933)	0	0
162	NET ENERGY COST CONSER.	0	0	0	0	0	0	0	0	0	0
163	TOTAL CUSTOMER ASSISTANCE	17,815	7,974	1,619	2,055	5,901	268	0	17,815	0	0
	ADMIN. & GENERAL EXPENSE										
	924-PROPERTY INSURANCE										
164	PRODUCTION	4,309	2,147	105	663	368	446	19	3,948	128	233
	RETAIL JURISDICTION										
165	DEMAND		2,001	97	788	335	408	15	3,644		
166	ENERGY		146	8	75	33	38	4	304		
167	TRANSMISSION	1,782	957	47	377	159	186	7	1,733	49	0
168	DISTRIBUTION	7,228	4,552	298	1,231	405	226	489	7,201	27	0
169	DEMAND	4,655	2,702	141	1,107	401	224	54	4,629	26	0
170	CUSTOMER	2,573	1,850	157	124	4	2	435	2,572	1	0
171	CUSTOMER ACCOUNTS	72	62	5	3	0	0	1	71	1	0
172	CUSTOMER ASSISTANCE	76	34	7	9	25	1	0	76	0	0
173	CUSTOMER	76	34	7	9	25	1	0	76	0	0
174	ENERGY	0	0	0	0	0	0	0	0	0	0
175	TOTAL ACCOUNT 924	13,467	7,752	462	2,483	957	859	516	13,029	205	233
176	DEMAND	10,442	5,660	285	2,272	695	818	76	10,006	203	233
177	CUSTOMER	2,721	1,946	169	136	29	3	436	2,719	2	0
178	ENERGY	304	146	8	75	33	38	4	304	0	0
	REG. COMM. EXP. & UNCOLL.										
179	STATE & FEDERAL	3,171	1,568	108	543	179	155	79	2,632	539	0
180	UNCOLLECTIBLE EXP.	3,809	3,401	256	149	3	0	0	3,809	0	0
181	TOTAL REG. COMM. & UNCOLL.	6,980	4,969	364	692	182	155	79	6,441	539	0
182	OTHER INDUSTRY DUES	705	332	18	173	78	94	10	705	0	0

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GULF POWER COMPANY
12 MONTHS ENDING DECEMBER 31, 2014
12/13 DEMAND ALLOCATION - WITH MDS METHODOLOGY
SCHEDULE 4.10 - ANALYSIS OF OPERATIONS AND MAINTENANCE EXPENSE
($000'S)

LINE NO. (1)	DESCRIPTION (2)	TOTAL ELECTRIC SYSTEM (3)	RATE CLASS RESIDENTIAL (4)	RATE CLASS GS (5)	RATE CLASS GSD/GSDT (6)	RATE CLASS LP/LPT (7)	RATE CLASS MAJOR ACCTS (8)	RATE CLASS OS (9)	TOTAL RETAIL SERVICE (10)	WHOLESALE (11)	UNIT POWER SALES (12)
163	MISC. A & G - OTHER REVS.	2	2	0	0	0	0	0	2	0	0
164	MISC. A & G - GULF POWER ENERGY SRVC CH	36	0	0	0	36	0	0	36	0	0
165	MISCELLANEOUS A & G	75,002	45,211	3,638	12,369	4,337	4,587	1,281	71,423	1,195	2,384
166	DEMAND	45,401	23,371	1,161	9,308	3,786	4,023	253	41,902	1,115	2,384
167	CUSTOMER	27,059	20,632	2,411	2,432	272	240	992	26,979	80	0
168	ENERGY	2,542	1,208	66	629	279	324	36	2,542	0	0
169	TOTAL MISCELLANEOUS A & G	75,040	45,213	3,638	12,369	4,373	4,587	1,281	71,461	1,195	2,384
190	DEMAND	45,401	23,371	1,161	9,308	3,786	4,023	253	41,902	1,115	2,384
191	CUSTOMER	27,097	20,634	2,411	2,432	308	240	992	27,017	80	0
192	ENERGY	2,542	1,208	66	629	279	324	36	2,542	0	0
193	TOTAL ADMIN. & GENERAL	98,192	58,266	4,482	15,717	5,690	5,695	1,886	91,636	1,939	2,617
194	TOTAL OPER. & MAINTENANCE	308,609	175,167	12,549	51,562	24,872	20,427	5,622	290,199	5,717	12,692
195	DEMAND	162,405	85,308	4,249	34,018	13,767	14,353	956	152,652	3,751	6,002
196	ENERGY	49,974	20,033	1,108	10,406	4,631	5,360	586	42,124	1,180	6,690
197	CUSTOMER	89,249	64,656	6,828	6,446	6,292	559	4,001	88,982	267	0
198	REVENUE	6,980	4,969	364	692	182	155	79	6,441	539	0

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12/13 DEMAND ALLOCATION - WITH MDS METHODOLOGY
ANALYSIS OF OPERATIONS AND MAINTENANCE EXPENSE

Line No.	Ftnt Label	Description
1	(A)	Allocated per Level 1 Demand Allocator; UPS directly assigned.
2	(B)	Allocated per Level 1 Energy Allocator; UPS directly assigned.
3	(B)	
5	(A)	
6	(B)	
8	(A)	
9	(B)	
11	(A)	
12	(B)	
14	(C)	Allocated per Level 2 Demand Allocator; UPS directly assigned.
15	(B)	
17	(A)	
18	(A)	
19	(A)	
20	(B)	
22	(A)	
23	(B)	
25	(A)	
26	(B)	
30	(D)	Allocated per Level 1 Demand Allocator.
31	(E)	Allocated per Level 1 Energy Allocator.
32	(E)	
33	(E)	
35	(D)	
36	(E)	
38	(D)	
39	(E)	
42	(D)	
43	(D)	
44	(E)	
46	(D)	
47	(E)	
49	(D)	
50	(E)	
58	(A)	
59	(B)	
60	(B)	

GULF POWER COMPANY
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12/13 DEMAND ALLOCATION - WITH MDS METHODOLOGY
ANALYSIS OF OPERATIONS AND MAINTENANCE EXPENSE

Line No.	Fmt Label	Description
63	(F)	Allocated per sum of Generation Demand Expenses and Purchased Power Demand Expenses.
64	(E)	
66	(D)	
67	(E)	
75	(C)	
76	(G)	Allocated per Transmission Substations Gross Plant; UPS directly assigned.
77	(H)	Allocated per Transmission Lines Gross Plant; UPS directly assigned.
78	(I)	Allocated per Transmission Account 358 Gross Plant.
79	(D)	
81	(J)	Allocated per Subtotal of Transmission Operations O & M Expense; UPS directly assigned.
82	(J)	
83	(J)	
85	(K)	Allocated per sum of Transmission Accounts 352, 354, and 355 Gross Plant; UPS directly assigned.
86	(L)	Allocated per Transmission Account 353 Gross Plant; UPS directly assigned.
87	(H)	
89	(M)	Allocated per Subtotal of Transmission Maintenance O & M Expense; UPS directly assigned.
90	(M)	
93	(N)	Allocated per Level 3 Demand Allocator.
94	(O)	Allocated per Distribution Substations Gross Plant.
95	(P)	Allocated per corresponding Distribution Gross Plant Accounts 365 and 368.
96	(P)	
98	(Q)	Allocated per corresponding Distribution Gross Plant Accounts 367 and 368.
99	(Q)	
101	(R)	Allocated per Distribution Account 373 Gross Plant.
102	(S)	Allocated per Distribution Account 370 Gross Plant.
103	(T)	Per analysis of information provided by Gulf Power Company.
105	(U)	Allocated per Distribution Account 369 Gross Plant.
106	(T)	
111	(V)	Allocated per corresponding Subtotal of Distribution Operations O & M.
112	(V)	
114	(V)	
115	(V)	

GULF POWER COMPANY
12 MONTHS ENDED DECEMBER 31, 2014
12/13 DEMAND ALLOCATION - WITH MDS METHODOLOGY
ANALYSIS OF OPERATIONS AND MAINTENANCE EXPENSE

Line No.	Ftnt Label	Description
117	(V)	
118	(V)	
121	(W)	Allocated per Distribution Account 361 Gross Plant.
122	(X)	Allocated per Distribution Account 362 Gross Plant.
123	(T)	
124	(Y)	Allocated per Common portion of Distribution Accounts 364 and 365.
125	(Z)	Allocated per Customer portion of Distribution Accounts 364 and 365.
128	(AA)	Allocated per Common portion of Distribution Accounts 366 and 367 Gross Plant.
129	(AB)	Allocated per Customer portion of Distribution Accounts 366 and 367 Gross Plant.
131	(AC)	Allocated per Distribution Account 368 Gross Plant.
132	(AC)	
134	(R)	
135	(S)	
139	(AD)	Allocated per corresponding Subtotal of Distribution Maintenance O & M.
140	(AD)	
142	(AD)	
143	(AD)	
149	(AE)	Direct assignment to rate provided by Gulf Power Company.
150	(AF)	Provided by Gulf Power to Class. Allocated to rate based on analysis of average number of customers within class.
151	(AF)	
152	(AF)	
153	(AF)	
154	(AG)	Provided by Gulf Power and assigned to Rate Class LP/LPT.
156	(AF)	
158	(AF)	
159	(AF)	
160	(AF)	
161	(AF)	

GULF POWER COMPANY
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12/13 DEMAND ALLOCATION - WITH MDS METHODOLOGY
ANALYSIS OF OPERATIONS AND MAINTENANCE EXPENSE

Line No.	Ftnt Label	Description
164	(AH)	Retail jurisdiction sum of corresponding demand and energy pieces; Wholesale allocated per Level 1 Demand Allocator; UPS directly assigned.
165	(D)	
166	(E)	
167	(AI)	Allocated per Transmission Gross Plant; UPS directly assigned.
168	(AJ)	Allocated per corresponding Distribution Gross Plant.
169	(AJ)	
170	(AJ)	
171	(AK)	Allocated per Customer Accounts O & M Expense.
172	(AL)	Allocated per corresponding Customer Assistance O & M Expense.
173	(AL)	
174	(AL)	
179	(AM)	Provided by Gulf Power to jurisdiction. Allocated to rate per Retail Revenue from Sales.
180	(AE)	
182	(AN)	Allocated per Retail MWH Sales.
183	(T)	
184	(AO)	A&G Overheads related to Gulf Power Energy Services. Assigned to Rate Class LP/LPT.
185	(AP)	Allocated per corresponding Salaries and Wages; UPS directly assigned.
186	(AP)	
187	(AP)	
188	(AP)	

GULF POWER COMPANY
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12/13 DEMAND ALLOCATION - WITH MDS METHODOLOGY
SCHEDULE 4.20 - ANALYSIS OF DEPRECIATION EXPENSE
($000'S)

LINE NO. (1)	DESCRIPTION (2)	TOTAL ELECTRIC SYSTEM (3)	RATE CLASS RESIDENTIAL (4)	RATE CLASS GS (5)	RATE CLASS GSD/GSDT (6)	RATE CLASS LP/LPT (7)	RATE CLASS MAJOR ACCTS (8)	RATE CLASS OS (9)	TOTAL RETAIL SERVICE (10)	WHOLESALE (11)	UNIT POWER SALES (12)
1	TOTAL PRODUCTION	52,105	23,360	1,149	9,405	4,018	4,867	213	43,012	1,322	7,771
	RETAIL JURISDICTION										
2	DEMAND		21,785	1,062	8,588	3,654	4,447	187	39,703		
3	ENERGY		1,575	87	817	364	420	46	3,309		
	TRANSMISSION										
4	350-LAND AND LAND RIGHTS	211	114	5	44	19	22	1	205	6	0
5	352-STRUCTURES	197	106	5	42	18	20	1	192	5	0
6	353-STATION EQUIPMENT	3,896	2,065	101	814	334	382	18	3,692	85	119
7	354-TOWERS & FIXTURES	767	409	20	161	68	84	3	744	23	0
8	355-POLES & FIXTURES	5,796	3,085	150	1,216	518	630	24	5,623	173	0
9	356-OVERHEAD COND.	2,138	1,138	55	449	191	232	9	2,074	64	0
10	358-UNDERGROUND COND.	254	134	7	53	23	28	1	246	6	0
11	359-ROADS AND TRAILS	5	3	0	1	0	1	0	5	0	0
12	TOTAL TRANSMISSION	13,264	7,053	343	2,780	1,171	1,379	55	12,781	364	119
	DISTRIBUTION										
13	360-SUBSTATION LAND	13	8	0	3	1	1	0	13	0	0
14	361-STRUCTURES	441	239	12	94	47	39	2	433	8	0
15	362-STATION EQUIPMENT	5,191	2,803	137	1,105	505	536	21	5,107	84	0
	364-POLES & FIXTURES										
16	COMMON	2,142	1,266	69	529	181	84	33	2,142	0	0
17	CUSTOMER	4,139	3,606	272	163	2	0	96	4,139	0	0
18	TOTAL ACCOUNT 364	6,281	4,872	341	692	183	84	129	6,281	0	0

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12 MONTHS ENDING DECEMBER 31, 2014
12/13 DEMAND ALLOCATION - WITH MDS METHODOLOGY
SCHEDULE 4.20 - ANALYSIS OF DEPRECIATION EXPENSE
($000'S)

LINE NO. (1)	DESCRIPTION (2)	TOTAL ELECTRIC SYSTEM (3)	RATE CLASS RESIDENTIAL (4)	RATE CLASS GS (5)	RATE CLASS GSD/GSDT (6)	RATE CLASS LP/LPT (7)	RATE CLASS MAJOR ACCTS (8)	RATE CLASS OS (9)	TOTAL RETAIL SERVICE (10)	WHOLESALE (11)	UNIT POWER SALES (12)
	365-OVERHEAD COND.										
19	DEMAND	3,681	2,177	116	909	311	110	56	3,681	0	0
20	CUSTOMER	717	624	47	28	1	0	17	717	0	0
21	TOTAL ACCOUNT 365	4,398	2,801	165	937	312	110	73	4,398	0	0
	366-UNDG. CONDUIT										
22	COMMON	13	9	0	3	1	0	0	13	0	0
23	CUSTOMER	1	1	0	0	0	0	0	1	0	0
24	TOTAL ACCOUNT 366	14	10	0	3	1	0	0	14	0	0
	367-UNDERGROUND COND. & DEV.										
25	COMMON	4,325	2,570	139	1,072	360	116	66	4,325	0	0
26	CUSTOMER	208	181	14	6	0	0	5	208	0	0
27	TOTAL ACCOUNT 367	4,533	2,751	153	1,080	360	116	71	4,533	0	0
	368-LINE TRANSFORMERS										
28	COMMON	7,177	4,405	238	1,831	529	61	113	7,177	0	0
29	CUSTOMER	2,444	2,126	161	97	2	1	57	2,444	0	0
30	TOTAL ACCOUNT 368	9,621	6,531	399	1,928	531	62	170	9,621	0	0
31	369-SERVICES	2,838	2,531	191	114	2	0	0	2,838	0	0
32	370-METERS	4,485	3,357	443	604	34	19	10	4,477	8	0
33	373-STREET LIGHTING	2,671	0	0	0	0	0	2,671	2,671	0	0
34	TOTAL DISTRIBUTION	40,686	25,913	1,841	6,560	1,976	949	3,347	40,586	100	0
35	DEMAND	22,983	13,477	713	5,546	1,935	929	291	22,891	92	0
36	CUSTOMER	17,703	12,436	1,128	1,014	41	20	3,056	17,695	8	0
37	GENERAL PLANT	8,347	5,145	414	1,407	493	521	146	8,126	136	85
38	DEMAND	4,979	2,660	132	1,059	430	457	29	4,767	127	85
39	CUSTOMER	3,079	2,347	274	277	31	28	113	3,070	9	0
40	ENERGY	289	138	6	71	32	36	4	289	0	0
41	TOTAL DEPR. EXPENSE	114,402	61,471	3,747	20,152	7,658	7,716	3,761	104,505	1,922	7,975
42	DEMAND	90,022	44,975	2,250	17,973	7,190	7,212	542	80,142	1,905	7,975
43	CUSTOMER	20,782	14,783	1,402	1,291	72	48	3,169	20,765	17	0
44	ENERGY	3,598	1,713	95	888	398	456	50	3,598	0	0

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12/13 DEMAND ALLOCATION - WITH MDS METHODOLOGY
ANALYSIS OF DEPRECIATION EXPENSE

Line No.	Ftnt Label	Description
1	(A)	Retail jurisdiction sum of Lines 2 and 3; Wholesale allocated per Level 1 Demand Allocator; UPS directly assigned.
2	(B)	Allocated per corresponding Level 1 Demand Allocator.
3	(C)	Allocated per corresponding Level 1 Energy Allocator.
4	(D)	Allocated per Transmission Account 350 Gross Plant (Lines portion only); UPS directly assigned.
5	(E)	Allocated per corresponding Transmission Gross Plant; UPS directly assigned.
6	(E)	
7	(E)	
8	(E)	
9	(E)	
10	(E)	
11	(E)	
13	(F)	Allocated per corresponding Distribution Gross Plant.
14	(F)	
15	(F)	
16	(F)	
17	(F)	
19	(F)	
20	(F)	
22	(F)	
23	(F)	
25	(F)	
26	(F)	
28	(F)	
29	(F)	
31	(F)	
32	(F)	
33	(F)	
37	(G)	Allocated per corresponding Gross General Plant; UPS directly assigned.
38	(G)	
39	(G)	
40	(G)	

GULF POWER COMPANY
12 MONTHS ENDING DECEMBER 31, 2014
12/13 DEMAND ALLOCATION - WITH MDS METHODOLOGY
SCHEDULE 4.30 - ANALYSIS OF TAXES OTHER THAN INCOME TAXES
($000'S)

LINE NO. (1)	DESCRIPTION (2)	TOTAL ELECTRIC SYSTEM (3)	RATE CLASS RESIDENTIAL (4)	RATE CLASS GS (5)	RATE CLASS GSD/GSDT (6)	RATE CLASS LP/LPT (7)	RATE CLASS MAJOR ACCTS (8)	RATE CLASS OS (9)	TOTAL RETAIL SERVICE (10)	WHOLESALE (11)	UNIT POWER SALES (12)
	REAL & PERSONAL PROPERTY										
1	PRODUCTION	17,196	6,597	422	3,456	1,477	1,789	78	15,809	486	901
	RETAIL JURISDICTION										
2	DEMAND		6,009	390	3,156	1,343	1,634	61	14,593		
3	ENERGY		578	32	300	134	155	17	1,216		
4	TRANSMISSION	2,598	1,369	68	647	230	268	11	2,513	71	14
5	DISTRIBUTION	5,988	3,759	246	1,017	334	186	404	5,946	22	0
6	DEMAND	3,843	2,230	117	914	331	186	45	3,823	21	0
7	CUSTOMER	2,124	1,529	129	103	3	0	359	2,123	1	0
8	CUSTOMER ACCOUNTS	120	104	6	5	0	0	2	119	1	0
9	CUSTOMER ASSISTANCE	128	57	12	15	42	2	0	128	0	0
10	CUSTOMER	128	57	12	15	42	2	0	128	0	0
11	ENERGY	0	0	0	0	0	0	0	0	0	0
12	TOTAL ELECTRIC PROP. TAXES	26,010	13,696	756	5,040	2,083	2,245	495	24,515	580	915
13	DEMAND	22,422	11,628	575	4,617	1,904	2,088	117	20,929	578	915
14	CUSTOMER	2,372	1,690	149	123	45	2	381	2,370	2	0
15	ENERGY	1,216	578	32	300	134	155	17	1,216	0	0
	PAYROLL TAXES										
16	PRODUCTION	3,419	1,698	83	682	291	353	15	3,122	96	201
	RETAIL JURISDICTION										
17	DEMAND		1,582	77	623	265	323	12	2,882		
18	ENERGY		116	6	59	26	30	3	240		
19	TRANSMISSION	299	158	8	62	28	32	1	287	9	3
20	DISTRIBUTION	1,600	1,083	72	245	72	28	98	1,698	1	0
21	DEMAND	854	507	27	209	71	28	11	853	1	0
22	CUSTOMER	745	576	45	36	1	0	87	745	0	0
23	CUSTOMER ACCOUNTS	958	834	83	38	1	1	13	950	8	0
24	CUSTOMER ASSISTANCE	1,010	659	134	170	25	23	0	1,011	0	0
25	CUSTOMER	1,010	659	134	170	25	23	0	1,011	0	0
26	ENERGY	0	0	0	0	0	0	0	0	0	0
27	SUBTOTAL ELEC. PAYROLL TAXES	7,286	4,432	360	1,197	415	437	127	6,968	114	204
28	DEMAND	4,332	2,247	112	894	362	383	24	4,022	106	204
29	CUSTOMER	2,714	2,069	242	244	27	24	100	2,706	6	0
30	ENERGY	240	116	6	59	26	30	3	240	0	0
31	ECCR PAYROLL ADJUSTMENT	(369)	(324)	(28)	(17)	0	0	0	(369)	0	0
32	NET ELEC. PAYROLL TAXES	6,917	4,106	332	1,180	415	437	127	6,599	114	204
33	DEMAND	4,332	2,247	112	894	362	383	24	4,022	106	204
34	CUSTOMER	2,714	2,069	242	244	27	24	100	2,706	6	0
35	ENERGY	(129)	(208)	(22)	42	26	30	3	(129)	0	0

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SCHEDULE 4.30 - ANALYSIS OF TAXES OTHER THAN INCOME TAXES
($000'S)

LINE NO. (1)	DESCRIPTION (2)	TOTAL ELECTRIC SYSTEM (3)	RATE CLASS RESIDENTIAL (4)	RATE CLASS GS (5)	RATE CLASS GSD/GSDT (6)	RATE CLASS LP/LPT (7)	RATE CLASS MAJOR ACCTS (8)	RATE CLASS OS (9)	TOTAL RETAIL SERVICE (10)	WHOLESALE (11)	UNIT POWER SALES (12)
	REVENUE TAXES										
36	GROSS RECEIPTS TAX	0	0	0	0	0	0	0	0	0	0
37	FLA REG. COMM. ASSESSMENT	402	239	17	83	27	24	12	402	0	0
38	FUEL & ECCR REL. REV TAXES	0	0	0	0	0	0	0	0	0	0
39	FRANCHISE FEE REV. ADJ.	0	0	0	0	0	0	0	0	0	0
40	TOTAL REVENUE TAXES	402	239	17	83	27	24	12	402	0	0
	OTHER TAXES										
41	MISS. STATE FRAN. TAX	307	164	8	64	27	34	1	298	9	0
42	FRANCHISE FEE	41,160	24,514	1,696	8,467	2,602	2,431	1,230	41,160	0	0
43	MISCELLANEOUS TAXES	105	66	5	18	6	6	2	103	2	0
44	DEMAND	62	35	2	13	5	5	0	60	2	0
45	CUSTOMER	39	28	3	4	1	1	2	39	0	0
46	ENERGY	4	3	0	1	0	0	0	4	0	0
47	TOTAL OTHER TAXES	41,572	24,744	1,709	8,569	2,635	2,471	1,233	41,561	11	0
48	FRANCHISE FEE ADJUSTMENT	(41,160)	(24,514)	(1,696)	(8,467)	(2,602)	(2,431)	(1,230)	(41,160)	0	0
49	TOTAL TAXES OTHER THAN INC.	33,741	18,473	1,118	8,385	2,558	2,746	637	31,917	706	1,119
50	DEMAND	27,123	14,074	697	5,588	2,298	2,510	142	25,309	695	1,119
51	CUSTOMER	5,125	3,787	394	371	73	27	463	5,115	10	0
52	ENERGY	1,091	373	10	343	160	165	20	1,091	0	0
53	REVENUE RELATED	402	239	17	83	27	24	12	402	0	0

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GULF POWER COMPANY
12 MONTHS ENDED DECEMBER 31, 2014
12/13 DEMAND ALLOCATION - WITH MDS METHODOLOGY
ANALYSIS OF TAXES OTHER THAN INCOME TAXES

Line No.	Ftnt Label	Description
1	(A)	Retail jurisdiction sum of Lines 2 and 3; Wholesale allocated per Level 1 Demand Allocator; UPS directly assigned.
2	(B)	Allocated per Level 1 Demand Allocator.
3	(C)	Allocated per Level 1 Energy Allocator.
4	(D)	Allocated per Transmission Gross Plant; UPS directly assigned.
5	(E)	Allocated per corresponding Distribution Gross Plant.
6	(E)	
7	(E)	
8	(F)	Allocated per corresponding Operations and Maintenance Expense.
9	(F)	
10	(F)	
11	(F)	
16	(G)	Allocated per corresponding Salaries and Wages; UPS directly assigned.
17	(H)	Allocated per corresponding Salaries and Wages.
18	(H)	
19	(G)	
20	(H)	
21	(H)	
22	(H)	
23	(H)	
24	(H)	
25	(H)	
26	(H)	
31	(I)	Provided by Gulf Power to Class. Allocated to rate per average number of customers within class.
36	(J)	Allocated per Retail Revenue from Sales.
37	(J)	
38	(K)	Allocated per Retail MWH Sales.
39	(J)	
41	(B)	
42	(J)	
43	(H)	
44	(H)	
45	(H)	
46	(H)	
48	(J)	

GULF POWER COMPANY
12 MONTHS ENDING DECEMBER 31, 2014
12/13 DEMAND ALLOCATION - WITH MDS METHODOLOGY
SCHEDULE 5.0 - LINE ALLOCATORS AND PERCENTAGES

LINE NO. (1)	DESCRIPTION (2)	TOTAL ELECTRIC SYSTEM (3)	RATE CLASS RESIDENTIAL (4)	RATE CLASS GS (5)	RATE CLASS GSD/GSDT (6)	RATE CLASS LP/LPT (7)	RATE CLASS MAJOR ACCTS (8)	RATE CLASS OS (9)	TOTAL RETAIL SERVICE (10)	WHOLESALE (11)	UNIT POWER SALES (12)
1	ENERGY - LEVEL 1	12,216,812	5,643,768	312,270	2,930,180	1,304,356	1,508,184	164,657	11,863,415	356,397	0
2	%	1.0000000	0.4618539	0.0255544	0.2397893	0.1067411	0.1234212	0.0134746	0.9708345	0.0291655	0.0000000
3	MWH SALES	11,505,326	5,264,445	291,283	2,733,887	1,233,654	1,477,619	153,590	11,154,278	351,048	0
4	%	1.0000000	0.4575859	0.0253172	0.2376019	0.1072245	0.1284291	0.0133495	0.9694882	0.0305118	0.0000000
	CP DEMAND										
5	LEVELS 1 & 2	2,149,333	1,144,164	55,768	451,029	191,920	233,603	6,774	2,085,247	64,086	0
6	%	1.0000000	0.5323344	0.0259420	0.2098456	0.0892929	0.1086863	0.0040822	0.9701833	0.0298167	0.0000000
7	LEVEL 3	1,892,426	1,123,290	54,741	442,800	163,856	99,125	8,614	1,892,426	0	0
8	%	1.0000000	0.5935714	0.0289284	0.2339854	0.0865851	0.0523799	0.0045518	1.0000000	0.0000000	0.0000000
	NCP DEMAND										
9	LEVEL 4	2,486,404	1,450,645	78,399	606,449	220,097	93,569	37,246	2,486,404	0	0
10	%	1.0000000	0.5834309	0.0315311	0.2439056	0.0885202	0.0376323	0.0149799	1.0000000	0.0000000	0.0000000
11	LEVEL 5	2,250,357	1,396,380	75,458	580,066	156,305	4,295	35,853	2,250,357	0	0
12	%	1.0000000	0.6205149	0.0335316	0.2577662	0.0703457	0.0019086	0.0159321	1.0000000	0.0000000	0.0000000
	AVERAGE NO. OF CUSTOMERS										
13	LEVEL 4 AND BELOW	443,319	386,033	29,156	17,494	276	48	10,312	443,319	0	0
14	%	1.0000000	0.8707793	0.0657675	0.0394614	0.0006227	0.0001083	0.0232609	1.0000000	0.0000000	0.0000000
15	LEVEL 5	443,246	386,033	29,154	17,486	248	33	10,312	443,246	0	0
16	%	1.0000000	0.8709227	0.0657739	0.0394048	0.0005596	0.0000745	0.0232647	1.0000000	0.0000000	0.0000000
17	TOTAL	443,351	386,033	29,156	17,497	284	68	10,312	443,350	1	0
18	%	1.0000000	0.8707184	0.0657628	0.0394653	0.0006407	0.0001534	0.0232592	0.9999977	0.0000023	0.0000000

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12 MONTHS ENDING DECEMBER 31, 2014
12/13 DEMAND ALLOCATION - WITH MDS METHODOLOGY
SCHEDULE 5.0 - LINE ALLOCATORS AND PERCENTAGES

LINE NO. (1)	DESCRIPTION (2)	TOTAL ELECTRIC SYSTEM (3)	RATE CLASS RESIDENTIAL (4)	RATE CLASS GS (5)	RATE CLASS GSD/GSDT (6)	RATE CLASS LP/LPT (7)	RATE CLASS MAJOR ACCTS (8)	RATE CLASS OS (9)	TOTAL RETAIL SERVICE (10)	WHOLESALE (11)	UNIT POWER SALES (12)
	SALARIES AND WAGES										
19	PRODUCTION	37,806	19,921	979	6,020	3,426	4,152	161	36,679	1,127	0
	RETAIL JURISDICTION										
20	12/13 DEMAND RELATED		16,579	805	7,323	3,116	3,793	142	33,858		
21	1/13 ENERGY RELATED		1,342	74	697	310	359	39	2,821		
22	%	1.0000000	0.5269269	0.0258954	0.2121356	0.0906205	0.1098238	0.0047876	0.9701899	0.0298101	0.0000000
23	TRANSMISSION	3,307	1,765	85	695	298	356	13	3,210	97	0
24	%	1.0000000	0.5337164	0.0257031	0.2101603	0.0895071	0.1076504	0.0039311	0.9706683	0.0293317	0.0000000
	DISTRIBUTION										
25	DEMAND	9,443	5,591	298	2,311	789	315	126	9,430	13	0
26	CUSTOMER	6,261	6,394	498	401	13	6	956	6,256	3	0
27	TOTAL DISTRIBUTION	17,704	11,975	796	2,712	802	321	1,082	17,686	16	0
28	%	1.0000000	0.6764008	0.0449616	0.1531857	0.0453005	0.0181315	0.0611161	0.9990962	0.0009038	0.0000000
29	CUSTOMER ACCOUNTS	10,595	9,219	697	419	11	16	145	10,509	86	0
30	%	1.0000000	0.8701274	0.0657857	0.0395470	0.0010382	0.0016989	0.0136857	0.9918830	0.0081170	0.0000000
	CUSTOMER ASSISTANCE										
31	CUSTOMER	11,170	7,290	1,480	1,679	278	243	0	11,170	0	0
32	ENERGY	0	0	0	0	0	0	0	0	0	0
33	TOTAL CUSTOMER ASST.	11,170	7,290	1,480	1,679	278	243	0	11,170	0	0
34	%	1.0000000	0.6526410	0.1324978	0.1682184	0.0248881	0.0217547	0.0000000	1.0000000	0.0000000	0.0000000
	SUBTOTAL SALARIES & WAGES										
35	DEMAND	47,735	25,935	1,288	10,329	4,201	4,464	281	46,498	1,237	0
36	CUSTOMER	30,028	22,893	2,675	2,899	302	267	1,101	29,937	89	0
37	ENERGY	2,821	1,342	74	697	310	359	39	2,821	0	0
38	SUBTOTAL SALARIES & WAGES	80,582	50,170	4,037	13,725	4,813	5,090	1,421	79,256	1,326	0
39	%	1.0000000	0.6225966	0.0500980	0.1703234	0.0597280	0.0631655	0.0176342	0.9835447	0.0164553	0.0000000
40	ADMINISTRATIVE & GENERAL	16,913	10,530	847	2,881	1,010	1,069	298	16,635	278	0
41	%	1.0000000	0.6225980	0.0500798	0.1703423	0.0597174	0.0632058	0.0176196	0.9835629	0.0164371	0.0000000
42	TOTAL SALARIES & WAGES	97,495	60,700	4,884	16,606	5,823	6,159	1,719	95,891	1,604	0
43	%	1.0000000	0.6225980	0.0500949	0.1703267	0.0597261	0.0631725	0.0176317	0.9835479	0.0164521	0.0000000

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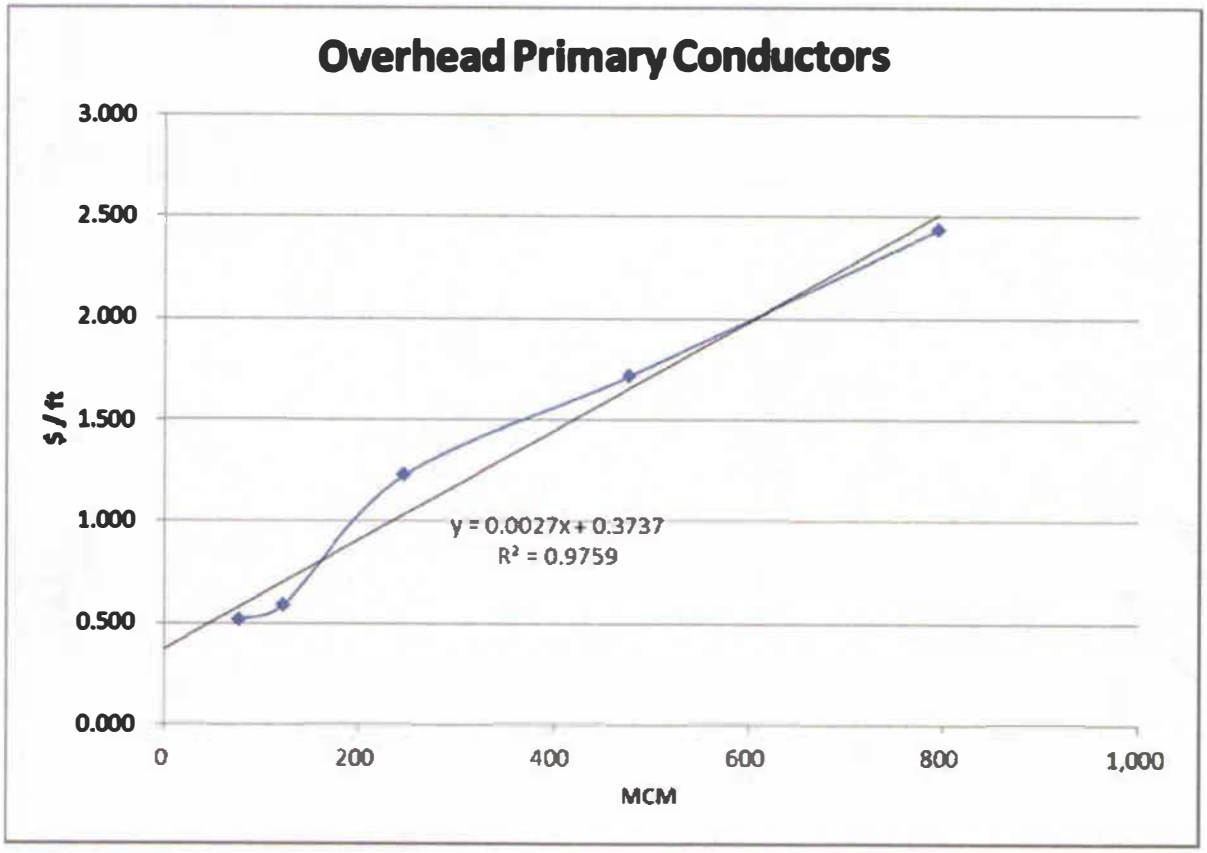
12 MONTHS ENDED DECEMBER 31, 2014
12/13 DEMAND ALLOCATION - WITH MDS METHODOLOGY
ANALYSIS OF LINE ALLOCATORS AND PERCENTAGES

Line No.	Fmt Label	Description
1	(A)	Energy at point of generation.
2	(B)	Percent of above lines total.
3	(C)	Total sales of energy at point of delivery.
4	(B)	
5	(D)	Coincident peak demand at Levels 1 & 2.
6	(B)	
7	(E)	Coincident peak demand at Level 3.
8	(B)	
9	(F)	Non-coincident peak demand at Level 4.
10	(B)	
11	(G)	Non-coincident peak demand at Level 5.
12	(B)	
13	(H)	Average number of customers at Levels 4 & 5.
14	(B)	
15	(I)	Average number of common customers at Level 5.
16	(B)	
17	(J)	Total average number of customers at all levels.
18	(B)	
19	(K)	Retail Jurisdiction sum of lines 2 & 3; Wholesale and Total Retail Service Allocated per Level 1 Demand Allocator.
20	(L)	Allocated per corresponding Level 1 Demand Allocator.
21	(M)	Allocated per corresponding Level 1 Energy Allocator.
22	(B)	
23	(N)	Allocated per Total Transmission O & M Expense excluding UPS.
24	(B)	
25	(O)	Allocated per demand related Distribution O & M Expense.
26	(P)	Allocated per customer related Distribution O & M Expense.
28	(B)	
29	(Q)	Allocated per Customer Accounts Expense excluding UPS.
30	(B)	
31	(R)	Allocated per customer related Customer Assistance Expense excluding UPS and Gulf Power Energy Services.
32	(S)	Allocated per energy related Customer Assistance Expense excluding UPS.
34	(B)	
40	(T)	Allocated per Subtotal Salaries and Wages.
41	(B)	

Minimum Distribution System
Account 365 – Overhead Regression
Schedule 6.1

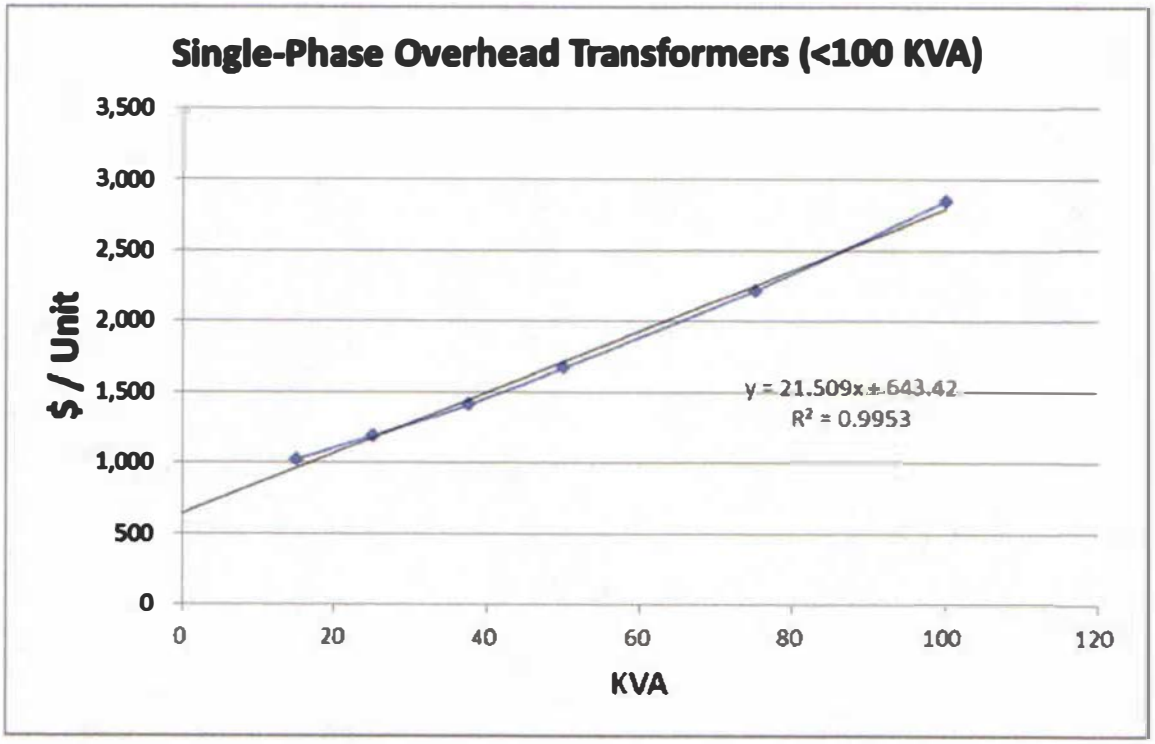


Account 365 – Overhead Primary Conductors

Size	MCM	$ / ft
#2	77.47	0.517
1/0	123.30	0.590
4/0	246.90	1.228
477	477.00	1.715
795	795.00	2.438

Zero Intercept = .3737

Minimum Distribution System
Account 368 – Single Phase Transformer Regression
Schedule 6.2



Account 368 – Singe Phase Overhead Transformers <100 kVA

kVA	$ / ea
15	1,022
25	1,193
37.5	1,412
50	1,672
75	2,219
100	2,848

Zero Intercept = 643.42

GULF POWER COMPANY
TWELVE MONTHS ENDED 12/31/12
MINIMUM DISTRIBUTION SYSTEM
ACCOUNT 364 - POLES, TOWERS AND FIXTURES (MASS ACCOUNT)
Schedule 6.3

		PRIMARY LEVEL 4			
		12-31-12 TOTAL LEVEL 4 COSTS	CUSTOMER-RELATED COMPONENT	DEMAND-RELATED COMPONENT	NOTES
	COMPONENT SPLIT ANALYSIS OF MASS ACCOUNT RECORDS				
1.	AVERAGE UNIT COST OF MRSS POLES		247.06		(A)
2.	TOTAL NUMBER OF POLES		203,779		(B)
3.	TOTAL COST OF POLES	76,397,964	50,344,627	26,053,337	(C)
4.	PERCENTAGE OF TOTAL COST OF POLES		65.90%	34.10%	

			PRIMARY LEVEL 4			SECONDARY LEVEL 5			
		12-31-12 TOTAL ALL COSTS	12-31-12 TOTAL LEVEL 4 COSTS	CUSTOMER-RELATED COMPONENT	DEMAND-RELATED COMPONENT	12-31-12 TOTAL LEVEL 5 COSTS	CUSTOMER-RELATED COMPONENT	DEMAND-RELATED COMPONENT	
5.	*PRIMARY / SECONDARY SPLIT OF OVERHEAD LINES FROM ACCOUNT 365*	111,303,221	86,050,521			25,252,700			(D)
	ANALYSIS OF ACCOUNT 364								
6.	POLES (WOOD, CONCRETE)	76,002,842	57,988,045	38,211,565	19,774,480	17,016,797	11,213,706	5,803,091	(E)
7.	STEEL-REINFORCED POLE TRUSS	1,395,123	1,395,123	919,358	475,767	-	-	-	(F)
8.	TOTAL POLES	76,397,965	58,381,168	38,130,921	20,250,247	17,016,797	11,213,706	5,803,091	
9.	FIXTURE SETS	45,206,973	35,137,623	23,154,943	11,982,680	10,069,350	6,636,487	3,433,863	(G)
10.	OTHER ACCOUNT 364	1,758,990	1,367,195	900,952	466,243	391,795	258,185	133,610	(H)
11.	TOTAL ACCOUNT 364	123,363,928	95,885,986	63,185,816	32,699,170	27,477,542	18,107,376	9,370,564	
12.	PERCENTAGES AT LEVEL			65.90%	34.10%		65.90%	34.10%	
13.	PERCENTAGES OF TOTAL		77.73%	51.22%	26.51%	22.27%	14.68%	7.60%	

NOTES:

(A) MRSS INCLUDES 30 & 35-FOOT WOODEN POLES--MINIMUM REPLACEABLE SIZE--AND SMALLER.
(B) INCLUDES ALL POLE SIZES.
(C) TOTAL AMOUNT FOR ALL POLES. CUSTOMER COMPONENT EQUALS TOTAL NUMBER OF POLES (LINE 2) TIMES AVERAGE UNIT COST OF MRSS POLES (LINE 1). DEMAND COMPONENT IS TOTAL MINUS CUSTOMER COMPONENT.
(D) FROM ACCOUNT 365, LINE 7, *TOTAL OVERHEAD LINES*.
(E) TOTAL AMOUNT ALLOCATED TO LEVEL PER PRIMARY / SECONDARY SPLIT OF OVERHEAD LINES FROM ACCOUNT 365 (LINE 5). WITHIN LEVEL, ALLOCATED TO COMPONENT PER TOTAL COST OF POLES (LINE 3).
(F) TOTAL AMOUNT ASSIGNED TO PRIMARY LEVEL. ALLOCATED TO COMPONENT PER TOTAL COST OF POLES (LINE 3).
(G) ALLOCATED PER TOTAL POLES (LINE 8).
(H) INCLUDES ADJUSTMENTS, INTERIM RUCs, AND NON-UNITIZED. ALLOCATED PER TOTAL POLES (LINE 8).

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GULF POWER COMPANY
TWELVE MONTHS ENDED 12/31/12
MINIMUM DISTRIBUTION SYSTEM - ZERO-INTERCEPT METHOD
ACCOUNT 365 - OVERHEAD CONDUCTORS AND DEVICES (CURRENT REPLACEMENT COST BASIS)
SCHEDULE 6.4

		PRIMARY LEVEL 4		
	12-31-12 TOTAL LEVEL 4 COSTS	CUSTOMER-RELATED COMPONENT	DEMAND-RELATED COMPONENT	NOTES
COMPONENT SPLIT ANALYSIS OF MASS ACCOUNT RECORDS				
1. ZERO-INTERCEPT UNIT COST OF AAC/AAAC Wire ($/FT)		0.3737		(A)
2. TOTAL FEET OF MINIMUM SYSTEM PRIMARY OVERHEAD LINES		62,264,622		(B)
3. TOTAL COST OF PRIMARY OVERHEAD LINES (ADJ FOR VINTAGE)	142,492,281	23,268,364	119,223,897	(C)
4. PERCENTAGE OF TOTAL COST OF OVERHEAD LINES		16.33%	83.67%	

			PRIMARY LEVEL 4		SECONDARY LEVEL 5			
ANALYSIS OF ACCOUNT 365	12-31-12 TOTAL ALL COSTS	12-31-12 TOTAL LEVEL 4 COSTS	CUSTOMER-RELATED COMPONENT	DEMAND-RELATED COMPONENT	12-31-12 TOTAL LEVEL 5 COSTS	CUSTOMER-RELATED COMPONENT	DEMAND-RELATED COMPONENT	
5. PRIMARY LINES	86,060,621	86,060,621	14,061,674	71,998,947	-	-	-	(D)
6. SECONDARY LINES	25,252,700	-	-	-	25,252,700	4,123,656	21,129,044	(E)
7. TOTAL OVERHEAD LINES	111,303,321	86,060,621	14,061,674	71,998,947	25,252,700	4,123,656	21,129,044	
8. PRIMARY SWITCHGEAR	4,521,010	4,521,010	738,261	3,782,749	-	-	-	(F)
9. SECONDARY SWITCHGEAR	2,026	-	-	-	2,026	331	1,695	(G)
10. OTHER EQUIPMENT	12,364,788	9,682,616	1,664,600	8,017,616	2,612,160	469,212	2,362,838	(H)
11. TOTAL SWITCHGEAR AND OTHER EQUIPMENT	16,917,804	14,103,626	2,303,061	11,800,567	2,614,176	469,643	2,364,533	
12. SUBTOTAL	128,221,025	100,164,149	16,364,736	83,799,414	28,066,876	4,593,199	23,493,677	
13. OTHER 365	2,844,243	2,221,654	362,796	1,858,858	622,589	101,686	520,923	(I)
14. TOTAL ACCOUNT 365	131,065,268	102,375,803	16,717,521	85,658,282	28,689,465	4,694,868	24,004,600	
15. PERCENTAGES AT LEVEL			16.33%	83.67%		16.33%	83.67%	
16. PERCENTAGES OF TOTAL		78.11%	12.76%	65.36%	21.89%	3.57%	18.31%	

NOTES:
(A) Y-AXIS INTERCEPT OF REGRESSION BASED ON COST FROM MAXIMO SSTEM OF AAC AND AAAC WIRE SIZES.
(B) TWO TIMES TOTAL PRIMARY OVERHEAD CIRCUIT-MILES FROM DISTGIS AUTOMATED MAPPING SYSTEM, CONVERTED TO FEET.
(C) TOTAL AMOUNT FOR ALL PRIMARY WIRE TYPES AND SIZES, ADJUSTED FOR VINTAGE BY HANDY-WHITMAN RATIOS. CUSTOMER COMPONENT EQUALS TOTAL FEET OF MINIMUM SYSTEM OVERHEAD LINES (LINE 2) TIMES UNIT COST OF ZERO-INTERCEPT (LINE 1). DEMAND COMPONENT IS TOTAL MINUS CUSTOMER COMPONENT.
(D) INCLUDES ALL OVERHEAD WIRE TYPES AND SIZES EXCEPT N-PLEX. ALLOCATED PER TOTAL COST OF PRIMARY OVERHEAD LINES (ADJ FOR VINTAGE) (LINE 3).
(E) INCLUDES ALL DUPLEX, TRIPLEX, AND QUADRUPLEX. ALLOCATED TO COMPONENT PER LINE 3.
(F) INCLUDES ALL SWITCHES SPECIFIED FOR USAGE AT 5 KV AND ABOVE. ALLOCATED PER PRIMARY LINES (LINE 5).
(G) INCLUDES ALL SWITCHES SPECIFIED FOR USAGE AT 4.9 KV AND BELOW. ALLOCATED PER SECONDARY LINES (LINE 6).
(H) INCLUDES ALL OTHER UNITIZED EQUIPMENT. ALLOCATED PER TOTAL OVERHEAD LINES (LINE 7).
(I) INCLUDES ADJUSTMENTS, INTERIM RUCs, AND NON-UNITIZED. ALLOCATED PER SUBTOTAL (LINE 12).

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GULF POWER COMPANY
TWELVE MONTHS ENDED 12/31/12
MINIMUM DISTRIBUTION SYSTEM - ZERO - INTERCEPT - METHOD
ACCOUNT 366 - UNDERGROUND CONDUIT ANALYSIS (MASS ACCOUNT)
SCHEDULE 6.5

	12-31-12 TOTAL ALL COSTS	12-31-12 TOTAL LEVEL 4 COSTS	PRIMARY LEVEL 4 CUSTOMER-RELATED COMPONENT	PRIMARY LEVEL 4 DEMAND-RELATED COMPONENT	12-31-12 TOTAL LEVEL 5 COSTS	SECONDARY LEVEL 5 CUSTOMER-RELATED COMPONENT	SECONDARY LEVEL 5 DEMAND-RELATED COMPONENT	NOTES
1. *TOTAL UNDERGROUND LINES FROM ACCOUNT 367*	106,604,167	74,657,835	3,431,394	71,226,241	31,946,552	1,468,319	30,476,233	(A)
ANALYSIS OF ACCOUNT 366								
2. DUCT LINES, MANHOLES, AND SPLICING CHAMBERS	994,328	696,352	32,006	664,346	297,974	13,695	284,279	(B)
3. TRANSFOMER VAULTS AND SUMP PUMPS	166,360	0	0	0	166,360	0	166,360	(C)
4. TOTAL ACCOUNT 366	1,160,686	696,352	32,006	664,346	464,334	13,695	450,639	
5. PERCENTAGES AT LEVEL			4.60%	95.40%		2.95%	97.05%	
6. PERCENTAGES OF TOTAL		59.99%	2.76%	57.24%	40.01%	1.18%	38.83%	

NOTES:
(A) FROM ANALYSIS OF ACCOUNT 367, LINE 7, *TOTAL UNDERGROUND LINES*.
(B) ALLOCATED PER TOTAL UNDERGROUND LINES FROM ACCOUNT 367 (LINE 1).
(C) ASSIGNED TO SECONDARY LEVEL 6 DEMAND-RELATED COMPONENT.

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GULF POWER COMPANY
TWELVE MONTHS ENDED 12/31/12
MINIMUM DISTRIBUTION SYSTEM - ZERO - INTERCEPT - METHOD
ACCOUNT 367 - UNDERGROUND CONDUCTORS (CURRENT REPLACEMENT COST BASIS)
SCHEDULE 6.6

		PRIMARY LEVEL 4		
	12-31-12 TOTAL LEVEL 4 COSTS	CUSTOMER-RELATED COMPONENT	DEMAND-RELATED COMPONENT	NOTES
COMPONENT SPLIT ANALYSIS OF MASS ACCOUNT RECORDS				
1. ZERO-INTERCEPT UNIT COST OF AAC/AAAC WIRE ($/FT)		0.3737		(A)
2. TOTAL FEET OF PRIMARY UNDERGROUND MINIMUM SYSTEM LINES		19,283,228		(B)
3. TOTAL COST OF PRIMARY UNDERGROUND LINES (ADJ FOR VINTAGE)	156,866,989	7,206,879	149,657,110	(C)
4. PERCENTAGE OF TOTAL COST OF UNDERGROUND LINES		4.60%	95.40%	

			PRIMARY LEVEL 4			SECONDARY LEVEL 5		
ANALYSIS OF ACCOUNT 367	12-31-12 TOTAL ALL COSTS	12-31-12 TOTAL LEVEL 4 COSTS	CUSTOMER-RELATED COMPONENT	DEMAND-RELATED COMPONENT	12-31-12 TOTAL LEVEL 5 COSTS	CUSTOMER-RELATED COMPONENT	DEMAND-RELATED COMPONENT	
5. PRIMARY LINES	74,657,635	74,657,635	3,431,394	71,226,241	-	-	-	(D)
6. SECONDARY LINES	31,946,552	-	-	-	31,946,552	1,468,319	30,478,233	(E)
7. TOTAL UNDERGROUND LINES	106,604,187	74,657,635	3,431,394	71,226,241	31,946,552	1,468,319	30,478,233	
8. NEUTRALS	31,885	-	-	-	31,885	1,466	30,420	(F)
9. PRIMARY SWITCHGEAR	3,980,077	3,980,077	192,931	3,787,146	-	-	-	(G)
10. SECONDARY SWITCHGEAR	9,209	-	-	-	9,209	423	8,786	(H)
11. OTHER EQUIPMENT	18,306,523	12,820,626	579,254	12,231,272	5,485,897	252,148	5,233,891	(I)
12. TOTAL SWITCHGEAR AND OTHER EQUIPMENT	22,295,809	16,800,703	772,185	16,028,418	5,495,206	252,569	5,242,637	
13. SUBTOTAL	128,931,881	91,458,238	4,203,579	87,254,659	37,473,643	1,722,353	35,781,290	
14. OTHER 367	3,965,590	2,813,004	129,291	2,683,713	1,152,586	52,975	1,099,611	(J)
15. TOTAL ACCOUNT 367	132,897,471	94,271,242	4,332,870	89,938,372	38,626,229	1,775,328	36,850,901	
16. PERCENTAGES AT LEVEL			4.60%	95.40%		4.60%	95.40%	
17. PERCENTAGES OF TOTAL		70.94%	3.26%	67.68%	29.06%	1.34%	27.73%	

NOTES:
(A) FROM ACCOUNT 366, LINE 1, *ZERO-INTERCEPT UNIT COST OF AAC/AAAC WIRE*.
(B) TWO TIMES TOTAL PRIMARY UNDERGROUND CIRCUIT-MILES FROM DISTGIS AUTOMATED MAPPING SYSTEM, CONVERTED TO FEET.
(C) TOTAL AMOUNT FOR ALL PRIMARY WIRE TYPES AND SIZES, ADJUSTED FOR VINTAGE BY HANDY-WHITMAN RATIOS. CUSTOMER COMPONENT EQUALS TOTAL FEET OF MINIMUM SYSTEM UNDERGROUND LINES (LINE 2) TIMES UNIT COST OF ZERO-INTERCEPT (LINE 1). DEMAND COMPONENT IS TOTAL MINUS CUSTOMER COMPONENT.
(D) INCLUDES ALL UNDERGROUND CABLE SPECIFIED FOR USAGE AT 5 KV AND ABOVE. ALLOCATED PER TOTAL COST OF PRIMARY UNDERGOUND LINES ADJUSTED FOR VINTAGE (LINE 3).
(E) INCLUDES ALL UNDERGROUND CABLE SPECIFIED FOR USAGE AT 4.9 KV AND BELOW. ALLOCATED TO COMPONENT PER LINE 4.
(F) ASSIGNED TO SECONDARY. ALLOCATED TO COMPONENT PER SECONDARY LINES (LINE 6).
(G) INCLUDES ALL SWITCHES SPECIFIED FOR USAGE AT 5 KV AND ABOVE. ALLOCATED PER PRIMARY LINES (LINE 5).
(H) INCLUDES ALL SWITCHES SPECIFIED FOR USAGE AT 4.9 KV AND BELOW. ALLOCATED PER SECONDARY LINES (LINE 6).
(I) INCLUDES ALL OTHER UNITIZED EQUIPMENT. ALLOCATED PER TOTAL UNDERGROUND LINES (LINE 7).
(J) INCLUDES ADJUSTMENTS, INTERIM RUCs, AND NON-UNITIZED. ALLOCATED PER SUBTOTAL (LINE 13).

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TWELVE MONTHS ENDED 12/31/12
MINIMUM DISTRIBUTION SYSTEM - ZERO-INTERCEPT METHOD
ACCOUNT 368 - LINE TRANSFORMERS (CURRENT REPLACEMENT COST BASIS)
SCHEDULE 6.7

	12-31-12 TOTAL ALL COSTS	PRIMARY LEVEL 4 12-31-12 TOTAL LEVEL 4 COSTS	PRIMARY LEVEL 4 CUSTOMER-RELATED COMPONENT	PRIMARY LEVEL 4 DEMAND-RELATED COMPONENT	SECONDARY LEVEL 5 12-31-12 TOTAL LEVEL 5 COSTS	SECONDARY LEVEL 5 CUSTOMER-RELATED COMPONENT	SECONDARY LEVEL 5 DEMAND-RELATED COMPONENT	NOTES
COMPONENT SPLIT ANALYSIS OF MASS ACCOUNT RECORDS								
1. UNIT COST OF ZERO-INTERCEPT (1 PHASE O/H)						643.42		(A)
2. TOTAL NUMBER OF O/H TRANSFORMERS						116,771		(B)
3. TOTAL OVERHEAD TRANSFORMERS (ADJ FOR VINTAGE)					198,283,555	76,419,637	121,863,918	(C)
4. PERCENTAGE SPLIT OF OVERHEAD TRANSFORMERS						38.54%	61.46%	
5. UNIT COST OF ZERO-INTERCEPT (1 PHASE O/H)						643.42		(A)
6. TOTAL NUMBER OF PAD-MT TRANSFORMERS						29,600		(B)
7. TOTAL PAD-MT TRANSFORMERS (ADJ FOR VINTAGE)					148,016,545	19,045,232	128,971,313	(C)
8. PERCENTAGE SPLIT OF PAD-MT TRANSFORMERS						12.87%	87.13%	
9. UNIT COST OF ZERO-INTERCEPT (1 PHASE O/H)						643.42		(A)
10. TOTAL NUMBER OF VAULT/DRY TRANSFORMERS						120		(B)
11. TOTAL VAULT/DRY TRANSFORMERS (ADJ FOR VINTAGE)					863,270	77,210	786,059	(C)
12. PERCENTAGE SPLIT OF VAULT/DRY TRANSFORMERS						8.94%	91.06%	
13. *PRIMARY LINES FROM ACCOUNT 365*		86,050,521	14,051,674	71,998,847				(D)
ANALYSIS OF ACCOUNT 368								
TRANSFORMERS								
14. OVERHEAD TRANSFORMERS	73,262,011	0	0	0	73,262,011	28,235,606	45,026,405	(E)
15. PAD-MOUNTED TRANSFORMERS	73,515,978	0	0	0	73,515,976	9,459,273	64,056,705	(F)
16. VAULT AND UNDERGROUND DRY TRANSFORMERS	428,784	0	0	0	428,784	38,348	390,416	(G)
17. NETWORK PROTECTORS	666,040	0	0	0	666,040	59,670	606,470	(H)
18. REGULATORS AND CAPACITORS	9,076,167	9,076,167	0	9,076,167	0	0	0	(I)
19. SWITCHES	1,435,580	1,435,580	234,424	1,201,156	0	0	0	(J)
CUTOUTS AND ARRESTERS								
20. TRANSFORMER-RELATED	40,517,177	0	0	0	40,517,177	15,615,556	24,901,621	(K)
21. REGULATOR/CAPACITOR-RELATED	2,924,692	2,924,692	0	2,924,692	0	0	0	(L)
22. LINE/SWITCH-RELATED	21,927,157	21,927,157	3,580,609	18,346,548	0	0	0	(M)
23. OTHER UNITIZED ACCOUNT 368	3,344,574	0	0	0	3,344,574	430,345	2,914,229	(N)
24. SUBTOTAL	227,098,140	35,363,596	3,815,033	31,548,563	191,734,544	53,836,896	137,895,846	
25. OTHER 368	6,023,523	937,980	101,190	836,790	5,085,543	1,426,011	3,657,532	(O)
26. TOTAL ACCOUNT 368	233,121,663	36,301,576	3,916,223	32,385,353	196,820,087	55,266,709	141,553,378	
27. PERCENTAGES AT LEVEL			10.79%	89.21%		28.08%	71.92%	
28. PERCENTAGES OF TOTAL		15.57%	1.68%	13.89%	84.43%	23.71%	60.72%	

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NOTES:

(A) Y-AXIS INTERCEPT OF REGRESSION BASED ON COST FROM MAXIMO SYSTEM OF SINGLE-PHASE OVERHEAD TRANSFORMERS 100 KVA AND LESS.
(B) INCLUDES ALL OVERHEAD, PAD-MOUNTED, AND VAULT/UNDERGROUND DRY TRANSFORMERS, RESPECTIVELY.
(C) TOTAL AMOUNT FOR ALL TRANSFORMERS OF EACH RESPECTIVE TYPE ADJUSTED FOR VINTAGE USING HANDY-WHITMAN RATIOS. CUTOMER COMPONENT EQUALS TOTAL NUMBER OF TRANSFORMERS (LINE 2) TIMES UNIT COST OF ZERO-INTERCEPT (LINE 1). DEMAND COMPONENT IS TOTAL MINUS CUSTOMER COMPONENT.
(D) FROM ANALYSIS OF ACCOUNT 365, LINE 5, *PRIMARY LINES*.
(E) ALLOCATED PER TOTAL OVERHEAD TRANSFORMERS ADJUSTED FOR VINTAGE (LINE 3).
(F) ALLOCATED PER TOTAL PAD-MT TRANSFORMERS ADJUSTED FOR VINTAGE (LINE 7).
(G) ALLOCATED PER TOTAL VAULT/DRY TRANSFORMERS ADJUSTED FOR VINTAGE (LINE 11).
(H) ALLOCATED PER VAULT AND UNDERGROUND DRY TRANSFORMERS (LINE 16).
(I) ASSIGNED TO LEVEL 4 DEMAND COMPONENT.
(J) ALLOCATED PER PRIMARY LINES FROM ACCOUNT 365 (LINE 13).
(K) FROM ACCOUNT 368-A. ALLOCATED PER OVERHEAD TRANSFORMERS (LINE 14).
(L) FROM ACCOUNT 368-A. ALLOCATED PER REGULATORS AND CAPACITORS (LINE 18).
(M) FROM ACCOUNT 368-A. ALLOCATED PER PRIMARY LINES FROM ACCOUNT 365 (LINE 13).
(N) ALLOCATED PER PAD-MOUNTED TRANSFORMERS (LINE 15).
(O) ALLOCATED PER SUBTOTAL (LINE 24).

GULF POWER COMPANY
TWELVE MONTHS ENDED 12/31/12
MINIMUM DISTRIBUTION SYSTEM - ZERO-INTERCEPT METHOD
ACCOUNT 368-A - ANALYSIS OF CUTOUTS AND ARRESTERS
SCHEDULE 6.7

	QUANTITY	PERCENTAGE	AMOUNT ($)	NOTES
1. TOTAL FOR CUTOUTS	172,629		29,938,347	(A)
2. PROTECTION FOR OVERHEAD TRANSFORMERS	116,791	68.73%	20,577,601	(B)
3. REMAINDER FOR LINE PROTECTION	54,038	31.27%	9,360,746	(C)
4. TOTAL FOR ARRESTERS	211,080		35,430,679	(D)
5. PROTECTION FOR OVERHEAD TRANSFORMERS	116,791	56.28%	19,939,576	(E)
6. PROTECTION FOR REGULATORS AND AUTO-BOOSTERS	1,260	0.60%	211,496	(F)
7. PROTECTION FOR CAPACITORS	16,164	7.66%	2,713,196	(G)
6. PROTECTION FOR SWITCHES	3,360	1.59%	562,312	(H)
9. REMAINDER FOR LINE PROTECTION	71,515	33.88%	12,004,099	(I)
SUMMARY FOR CUTOUTS AND ARRESTERS				
10. Transformer-related			40,517,177	(J)
11. Regulator/Capacitor-related			2,924,692	(K)
12. Line/Switch-related			21,927,157	(L)

NOTES:
(A) TOTAL NUMBER AND AMOUNT FOR CUTOUTS
(B) ASSUMED 1 CUTOUT PER SINGLE PHASE TRANSFORMER AND 3 CUTOUTS PER THREE PHASE TRANSFORMER.
(C) DIFFERENCE BETWEEN TOTAL FOR CUTOUTS (LINE 1) AND PROTECTION FOR OVERHEAD TRANSFORMERS (LINE 2).
(D) TOTAL NUMBER AND AMOUNT FOR ARRESTERS.
(E) ASSUMED 1 ARRESTER PER SINGLE PHASE TRANSFORMER AND 3 ARRESTERS PER THREE PHASE TRANSFORMER.
(F) REGULATORS AND AUTO-BOOSTERS ALL SINGLE-PHASE. ASSUMED 2 ARRESTERS PER UNIT (ONE EACH ON LOAD SIDE AND SOURCE SIDE).
(G) ASSUMED ALL CAPACITORS 3-PHASE. ASSUMED SIX ARRESTERS PER CAPACITOR--TWO PER PHASE (ONE EACH ON LOAD SIDE AND SOURCE SIDE).
(H) ASSUMED TWO ARRESTERS PER SINGLE-PHASE SWITCH AND 6 ARRESTERS PER 3-PHASE SWITCH.
(I) DIFFERENCE BETWEEN TOTAL FOR ARRESTERS (LINE 4) AND [PROTECTION FOR OVERHEAD TRANSFORMERS (LINE 5) PLUS PROTECTION FOR REGULATORS (LINE 6) PLUS PROTECTION FOR CAPACITORS (LINE 7) PLUS PROTECTION FOR SWITCHES (LINE 6)].
(J) LINE 2 PLUS LINE 5
(K) LINE 6 PLUS LINE 7.
(L) LINE 3 PLUS LINE 6 PLUS LINE 9.

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Gulf Power Company
Twelve Months Ended 12/31/12
Minimum Distribution System
Account 369 – Services Analysis (Mass Account)
Schedule 6.8

		12-31-12 Total All Costs	Secondary ----------Level 5---------- Customer-Related Component	Demand-Related Component	Notes
1.	All Services	97,917,728	97,917,728	-	(A)
2.	Total Account 369	97,917,728	97,917,728	-	
3.	Percentages		100%		

Notes
(A) Assigned to Secondary Level 5 Customer-Related Component.

Gulf Power Company
Twelve Months Ended 12/31/12
Minimum Distribution System
Account 370 – Meters Analysis (Mass Account)
Schedule 6.9

		12-31-12 Total All Costs	Secondary ----------Level 5---------- Customer-Related Component	Demand-Related Component	Notes
1.	All Meters	73,759,011	73,759,011	-	(A)
2.	Total Account 370	73,759,011	73,759,011	-	
3.	Percentages		100%		

Notes
(A) Assigned to Customer-Related Component.

Responsibility for Minimum Filing Requirements

Schedule	Title
A-2	Full Revenue Requirements Bill Comparison – Typical Monthly Bills
A-3	Summary of Tariffs
A-5	Interim Revenue Requirements Bill Comparison – Typical Monthly Bills
E-8	Company-Proposed Allocation of the Rate Increase By Rate Class
E-9	Cost of Service – Load Data
E-11	Development of Coincident and Noncoincident Demands for Cost Study
E-12	Adjustment To Test Year Revenue
E-13a	Revenue From Sale of Electricity by Rate Schedule
E-13b	Revenues by Rate Schedule – Service Charges
E-13c	Base Revenue by Rate Schedule - Calculations
E-13d	Revenue by Rate Schedule – Lighting Schedule Calculation
E-14	Proposed Tariff Sheets and Support For Charges
E-16	Customers by Voltage Level
E-17	Load Research Data

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Allocation of Revenue Increase

		Rate Class Residential	Rate class GS	Rate class GSD/GSDT	Rate Class LP/LPT	Rate Class Major Accounts	Rate Class OS	Total Retail Service
Base Rate Revenue Increase ($000's)		44,303	2,372	13,194	7,104	6,570	850	74,393
% Base Rate Increase		14.9%	11.6%	12.8%	21.0%	22.3%	5.7%	14.9%
Indexed Rate of Return	Present	0.98	1.12	1.33	0.80	0.21	1.77	1.00
	Proposed	1.00	1.05	1.16	0.95	0.55	1.27	1.00

Proposed Tariff Sheets

Proposed Tariff Sheets consisting of 61 pages, including this cover sheet.

GULF POWER
A SOUTHERN COMPANY

Twenty-Seventh Revised Sheet No. ii
Canceling Twenty-Sixth Revised Sheet No. ii

TABLE OF CONTENTS

Section	Description
Section I	Description of Territory Served
Section II	Miscellaneous
Section III	Technical Terms and Abbreviations
Section IV	Rules and Regulations
Section V	List of Communities Served
Section VI	Rate Schedules

RS - Residential Service
GS - General Service - Non-Demand
GSD - General Service - Demand
LP - Large Power Service
PX - Large High Load Factor Power Service
OS - Outdoor Service
BB - Budget Billing (Optional Rider)
CR - Cost Recovery Clause - Fossil Fuel & Purchased Power
PPCC - Purchased Power Capacity Cost Recovery Clause
ECR - Environmental Cost Recovery Clause
-- - Billing Adjustments and Payment of Bills
ECC - Cost Recovery Clause - Energy Conservation
FLAT-1 - Residential/Commercial FlatBill
GSTOU - General Service Time-of-Use Conservation (Optional)
GSDT - General Service - Demand - Time-of-Use Conservation (Optional)
LPT - Large Power Service - Time-of-Use Conservation (Optional)
PXT - Large High Load Factor Power Service - Time-of-Use Conservation (Optional)
SBS - Standby and Supplementary Service
ISS - Interruptible Standby Service
RSVP - Residential Service Variable Pricing
SP - Surge Protection
RTP - Real Time Pricing
CIS - Commercial/Industrial Service Rider (Optional)
BERS - Building Energy Rating System (BERS)
PV - Rate Rider PV - Photovoltaics (Optional Rider)
MBFC - Military Base Facilities Charge (Optional Rider)
LBIR - Large Business Incentive Rider (Optional Rider)
SBIR - Small Business Incentive Rider (Optional Rider)

ISSUED BY: S. W. Connally, Jr.

GULF POWER
A SOUTHERN COMPANY

Section No. IV
First Revised Sheet No. 4.8
Canceling Original Sheet No. 4.8

PAGE	EFFECTIVE DATE

1.10 CONTINUITY OF SERVICE - The Company will exercise reasonable diligence and care to furnish and deliver a regular and uninterrupted supply of electrical energy, but in case the supply should be variable in frequency or voltage, interrupted or fail by reasons of legal process, strike, riot, war, flood, storm, fire, accident, breakdown, or on account of maintenance or repairs to its system, or any part thereof, or of cutting in new equipment or customers or any cause beyond the control of the Company or from the negligence of the Company, its employees, servants or agents, the Company shall not be held liable for any injury, loss, damage, or expense to any Customer, or to any other person, caused directly or indirectly by such variation, interruption, or failure, but shall restore its service to normal as quickly as practicable; and during such interruption the Customer shall have the right to use such other service as may be available. The Customer shall notify the Company promptly of any defect in service or of any trouble or accident to the electric supply.

Continuous service is further dependent upon and subject to conditions brought about by war, the necessities of war, or by the United States Government or any agency of the United States Government, and the Company assumes no obligation to continue the delivery of any quantity of power when or in the event it is required to supply such power to the United States Government, or to any person, firm, corporation, business or industry designated by the United States Government or other Governmental Agency either during time of war or at any other time.

1.11 INCREASE OF SERVICE - Increased service requirements shall be supplied at all times through the existing, or enlarged, service connection and such metering equipment as will properly measure the amount of energy and its maximum demand, provided that the necessary enlargement of the facilities in service does not require changes in point of delivery. The Customer

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GULF POWER
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Section No. VI
Second Revised Sheet No. 4.9
Canceling First Revised Sheet No. 4.9

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1.11 INCREASE OF SERVICE - (Continued)

shall give reasonable advance notice to the Company of any changes which affect the connected load under contract to the end that the Company will have ample time to provide adequate service facilities.

1.12 RIGHT-OF-WAY - The Customer, upon making application for service, thereby grants the Company, free of cost, right-of-way over and under property owned, leased, or controlled by the Customer, for the installation of poles, ducts, cables, wires, transformers, vaults, fixtures, and appurtenances necessary for service to the Customer; and the Customer shall provide, without cost to the Company, suitable location and housing for all apparatus installed and owned by the Company on Customer's premises; and all necessary permission for ingress and egress to and from the Customer's premises shall be provided by the Customer to enable the properly identified employees of the Company to read meters, install, repair, maintain, and remove the Company's property and inspect and test electrical equipment within or upon the premises at all reasonable times and to perform all other necessary duties in connection with the service to the Customer and the Company's property.

1.13 CUSTOMER WIRING - The wiring and electrical equipment in or upon the premises of the Customer to the Delivery Point shall be in conformity with the rules and regulations of constituted authorities pertaining thereto, and the rules set forth in the Company's "Electric Service and Meter Installations" as issued from time to time, but the Company does not assume responsibility therefore and shall not be liable for any defects or damages due to defective customer wiring.

ISSUED BY: S. W. Connally, Jr.

GULF POWER
A SOUTHERN COMPANY

Section No. VI
Fourth Revised Sheet No. 4.10
Canceling Third Revised Sheet No. 4.10

[redacted]

1.14 ENERGY AUDITS - The Company will offer energy audits to customers in accordance with Commission Rule 25-17.003, Florida Administrative Code.

1.15 PAYMENT FOR SERVICE - Employees of the Company are forbidden to demand or accept any personal compensation from Customers of the Company, and payment for any services rendered should only be made upon presentation of formal statement by the Company.

1.16 RESPONSIBILITY FOR PROPERTY OF THE COMPANY - All property of the Company that is placed in or upon the Customer's premises, and used in supplying service to him, is placed there under his protection; Customer shall be liable for any loss of or damage to such property, normal wear and tear excepted, and shall pay the Company the amount of any such loss or damage.

1.17 DAMAGES TO PROPERTY - Neither the Customer nor the Company shall be responsible for damage to the machinery, apparatus, appliances or other property of the other caused by lightning or by defects in or failure of the machinery, apparatus, or appliances of the one suffering such damages from such causes; and the Company shall not be in any way responsible for the transmission or control of electrical energy beyond the Delivery Point, and shall not be liable for damages on account of injuries to person or property resulting in any manner from the receiving, use, or

GULF POWER
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Section No. VI
Third Revised Sheet No. 4.11
Canceling Second Revised Sheet No. 4.11

1.17 DAMAGES TO PROPERTY - (continued)
application by the Customer of such electrical energy. The Customer must keep his, her, or its machinery, lines, apparatus and appliances in a safe condition and shall indemnify and save harmless the Company from the payment of any sums or sum of money to any person whomsoever, including attorney's fees and court costs, which it may be called upon to pay on account of damage to property or fatal or personal injuries to individuals resulting from or which may be in anyway caused by the operation and maintenance of the machinery, lines, apparatus and appliances belonging to the Customer.

Reverse phase relays, phase failure relays and low voltage or voltage unbalance releases, preferably of the adjustable time-delay type, with circuit breakers or equivalent devices shall be provided by the Customer to disconnect automatically all motor installations which cannot be safely reversed or which would be damaged by a phase or voltage failure.

1.18 STANDARD NOMINAL VOLTAGE - The Company will adopt a standard nominal voltage, or standard nominal voltages, as may be required by its distribution system, or for each of the several districts into which the system may be divided, and the voltages maintained at the Company's main service terminals as installed for each Customer or group of customers shall be maintained reasonably constant. Information as to the standard nominal voltage supplied to any district or area will be furnished by the Company upon request.

If an industrial Customer uses lighting incidental to his power service and the voltage regulation is unsatisfactory for lighting purposes, then the Customer shall install any required regulative apparatus at his own expense.

1.19 NOTICES - Any notice required or authorized to be given under these "Rules and Regulations" or under the provisions of any contracts between the Company and Customer, shall be in writing addressed to the Customer at the premises at which the service is rendered, or at such other address as may have been furnished by the Customer for receiving his bills from the Company, or at Customer's last known address, and mailed in the ordinary course of the Company's business; or by the Customer to the Company, by mail, addressed to the Company; or by either party by serving same personally upon the other. The date of serving or mailing any such notice shall be the date upon which the number of days specified for notice shall begin to run. Notice may be provided to customers via electronic mail if the customer consents to receiving notice in such format.

Notice to the Company by the Customer should not be given to employees of the Company when away from the office, or in the office after or before business hours, as such will not be accepted as binding and formal notification to the Company.

1.20 PROMISES - No promise, agreement, or representation of any employee or officer of the Company shall bind the Company unless the same be in writing and approved by the signature of an officer of the Company, and no employee or officer of the Company is authorized to waive this condition.

ISSUED BY: S. W. Connally, Jr.

GULF POWER
A SOUTHERN COMPANY

Section No. IV
Fifteenth Revised Sheet No. 4.13
Canceling Fourteenth Revised Sheet No. 4.13

PAGE	EFFECTIVE DATE
of	

2.5 NON-ASSIGNMENT OF DEPOSIT - The receipt for deposit cannot be assigned by the Customer without the written consent of the Company.

2.6 PAYMENT OF PREVIOUS ACCOUNTS REQUIRED - Applications for service will not be accepted by the Company until the Applicant has paid to the Company all sums at any time owing and then unpaid:

(1) By Applicant for service of the same class rendered by the Company whether at the premises applied for or at any other premises, or

(2) By the previous occupant of the premises as long as the current Applicant or Customer occupied the premises at the time the delinquency occurred and the previous Customer continues to occupy the premises and such previous Customer shall benefit from such service.

PART III
LINE EXTENSION AND SERVICE CONNECTION REGULATIONS

3.1 APPLIES TO ALL APPLICANTS - These regulations apply to all applicants requesting service from the regular distribution systems of the Company for residential, commercial and industrial usage. Customers requesting service from the transmission system of the Company may require individual consideration and will be handled accordingly as they request service.

3.2 CONNECTION OF INITIAL SERVICE - Where the Company's distribution circuits already are in place on the pole adjacent to the Customer's premises requiring only the installation of service wires and meter, the Company will place the service wires and meter completing the connection to provide service. The Customer shall pay a charge of $27.00 residential / $50.00 non-residential for such connection, in addition to the deposit provided for elsewhere. The Company shall have the discretion to waive the connection fee that would otherwise apply to the new or existing Customer as a consequence of significant damage to their premises caused by a natural disaster or other similar conditions for which an emergency has been declared by a governmental body authorized to make such a declaration.

3.3 CONNECTION OF EXISTING SERVICE - Where service has previously been connected at a premise, a $27.00 residential / $50.00 non-residential service charge shall be paid for all subsequent reconnections, except for restoration of service after violation of regulations as provided in Paragraph 4.11 of these Rules or at the Company's discretion as a consequence of significant damage to the new or existing Customer's premises caused by a natural disaster or other similar conditions for which an emergency has been declared by a governmental body authorized to make such a declaration.

3.4 SERVICE IF NEW OR UPGRADED FACILITIES ARE REQUIRED - When new or upgraded facilities are required to place the service applied for adjacent to the Customer's premises, a test will be run on the projected revenue vs. the estimated construction costs, exclusive of meters and services.

Contributions-in-aid-of-construction for new or upgraded overhead facilities:
$CIAC_{OH}$ = Construction Cost - (4 years expected incremental base energy revenue) - (4 years expected incremental base demand revenue)

Contributions-in-aid-of-construction for new or upgraded underground facilities:
$CIAC_{UG}$ = $CIAC_{OH}$ + Estimated difference between cost of providing the service underground and overhead

ISSUED BY: S. W. Connally, Jr.

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3.4 (continued)
If the revenue supports construction, then no CIAC is applicable. If the revenue/ construction comparison shows a CIAC to be owing, the applicant will pay to the Company in advance of making the extension the amount from the formula, adjusted by the approved tax effect multiplier. Such payment may be waived or a special agreement may be made providing for the repayment of such money to the applicant, when additional business is secured, upon terms to be fixed by the Company. Where more customers than the initial applicant are expected to be served by the new or upgraded facilities within a period not to exceed three years, the Company shall prorate the total CIAC over the number of end-use customers expected. Where the full amount of CIAC is required from the initial applicant, the Company will return to the initial applicant any subsequent CIAC payments received from such expected customers. Title to all lines will remain with the Company. When service is connected to the Customer's premises, a service charge shall be paid in accordance with the provisions of Paragraph 3.2 above. The Company shall apply the above formulas uniformly to residential, commercial, and industrial customers requiring new or upgraded facilities at any voltage level.

3.5 LIMITATIONS ON THREE PHASE SERVICE - In general, the Company will furnish single phase service for any residential or commercial loads involving no single motor larger than five horsepower. It has never contemplated supplying service to any motor rated at three horsepower or smaller at three phase anywhere. Therefore, unless already available, three phase service will not be furnished for residential loads or for commercial loads where no commercial motor exceeds three horsepower until the Customer makes a contribution to the Company equal to the excess of the cost of providing three phase service over the cost of furnishing service to such load at single phase.

3.6 UNDERGROUND SERVICE IN AN OVERHEAD AREA - Conversion of existing overhead facilities to underground shall be handled in accordance with the provisions of Part VI UNDERGROUND DISTRIBUTION FACILITIES.

3.7 CONNECTION OF TEMPORARY SERVICE - Where the Company's distribution circuits are already in place on the pole adjacent to the Customer's premises requiring only the installation of a service drop and meter, the Company will place the service drop and meter completing the connection to provide temporary service. The service drop and meter installation shall not exceed 200 amperes and must utilize self-contained, non-demand metering. The customer shall pay a charge of $110.00 for each such connection in addition to the deposit provided for elsewhere.

3.7.1 TEMPORARY SERVICE INVOLVING EXTENSIONS - In case the establishing of temporary service involves cost of labor and materials, other than as described in 3.7 above, the applicant must pay in advance the total estimated cost of installing and dismantling the necessary facilities, less the salvage value of the material returnable to stores for re-use, less projected revenues associated with the temporary service. This payment shall be in addition to the appropriate service charge for a Service Connection to existing distribution system and the deposit for guarantee of the energy billing provided for elsewhere.

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PART V
CONTRACT AND ENFORCEMENT REGULATIONS

5.1 CUTOFF REGULATIONS - Bills for service are payable monthly, unless otherwise stated in rate schedules, and are considered delinquent after the expiration of twenty (20) days from the date of mailing or delivery by the utility. If not paid at the Company's office or other designated place by the delinquent date, the Company at any time thereafter may suspend service after giving five (5) day's written notice to the customer of such delinquency and of the Company's intention to discontinue service. Such written notice will be separate and apart from any bill for service. If the amount due remains unpaid after suspension of service, the Company may treat the contract as canceled and at an end.

5.2 EXTENSION OF TIME FOR PAYMENT OF BILL - The Company may, however, extend the time for paying any one or more bills, or any part thereof, and its action in so doing shall be without prejudice to its rights thereafter to suspend service as provided in these rules; and by so doing, the Company shall not be held or considered as waiving its rights or its option thereafter to suspend service and/or treat the contract as canceled and at an end.

5.3 RESTORATION CHARGE - When the service of a Customer has been discontinued after violation of rules, all amounts due for service up to the date of discontinuance thereof shall become due and must be paid before service will be reconnected and the Company shall require the Customer to pay a restoration charge before reconnecting. The restoration charge shall be determined as follows:
(1) $60.00 if the service is restored at the meter during normal business hours.
(2) $80.00 if the service is restored at the meter after hours.
(3) $100.00 if the service is restored because of an inaccessible meter.

5.4 PREMISE VISIT CHARGE - Whenever payment for service is delinquent and a field service representative is required to call at the Customer's premise, and service is not suspended, a $30.00 fee shall be charged.

5.5 FAULTY WIRING ON CUSTOMER'S PREMISES - The Company reserves the right to disconnect from its lines, or to refuse to connect to its lines, any Customer or applicant whose wiring is not in accordance with standard good practice; however, the Company does not assume any responsibility for installation or maintenance inspection of Customer's wiring or installation.

5.6 MEDICALLY ESSENTIAL SERVICE - For purposes of this section, a Medically Essential Service Customer is a residential customer whose electric service is medically essential, as affirmed through the certificate of a doctor of medicine licensed to practice in the State of Florida. Service is "medically essential" if the customer has continuously operating electric-powered medical equipment necessary to sustain the life of or avoid serious medical complications requiring immediate hospitalization of the customer or another permanent resident at the service address. The Physician's certificate shall explain briefly and clearly, in non-medical terms, why continuance of electric service is medically essential, and shall be consistent with the requirements of the Company's tariff. A customer who is certified as a Medically Essential Service Customer must renew such certification periodically through the procedures outlined above. The Company may require certification no more frequently than 12 months.

The Company shall provide Medically Essential Service Customers with a limited extension of time, not to exceed thirty (30) days, beyond the date service would normally be subject to disconnection for non-payment of bills (following the requisite notice pursuant to Rule 25-6.105(5) of the Florida Administrative Code). The Company shall provide the Medically Essential Service Customer with written notice specifying the date of disconnection based on the limited extension. The Medically Essential Service

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6.2.2 (continued)

Any Applicant seeking the installation of underground distribution facilities pursuant to a written request hereunder shall execute the Agreement For Underground Construction Standards set forth in Section VII of this tariff, Standard Contract Forms, at Sheet no. 7.25. Failure to execute said agreement within 180 days after the delivery by Gulf Power Company of a binding cost estimate shall result in forfeiture of the deposit made. Any subsequent request for underground facilities will require the payment of a new deposit and the presentation of a new binding cost estimate. For good cause Gulf may extend the 180 day time limit. Upon execution of the Agreement For Underground Construction Standards, payment in full of the differential cost specified in the binding cost estimate, and compliance with the requirements of this tariff, Gulf shall proceed to install the facilities identified in a timely manner.

As a condition precedent to the conversion of any overhead distribution facilities, the Company may require that the Applicant obtain executed agreements with all affected pole licensees (e.g. telephone, cable TV, etc.) for the simultaneous conversion of those pole licensees' facilities and provide Gulf with a copy of the Agreement(s). Such agreements shall specifically acknowledge that the affected pole licensee will coordinate the conversion with Gulf and other licensees in a timely manner so as to not create unnecessary delays. Failure to present to Gulf Power Company executed copies of any necessary agreements with affected pole licensees within 180 days after delivery of the binding cost agreement to the Applicant shall result in forfeiture of the deposit paid for the binding cost estimate, the return of any differential cost paid for the binding cost estimate, the return of any differential cost paid less any actual cost incurred, and the termination of any Agreement For Underground Construction Standards entered into between the Applicant and Gulf Power Company.

6.2.3 CHANGES TO PLANS. The Applicant shall pay for all additional costs incurred by the Company due to changes made by the Applicant in the subdivision layout or grade after original agreed upon design has been completed by the Company.

6.2.4 UNDERGROUND INSTALLATIONS NOT COVERED. Where the Applicant requests underground electric facilities not specifically covered by these Rules and Regulations, or in areas where the terrain, loads, and/or equipment are not typical, and where overhead facilities would otherwise normally be provided, the Applicant and the Company may enter into an agreement outlining the terms and conditions of the installation prior to such installation.

6.2.5 TYPE OF SYSTEM PROVIDED. Underground residential distribution facilities are of standard Company design, generally with all cable in duct or conduit and above-grade appurtenances. Unless otherwise stated, service provided will be 120/240 volt single phase. If other types of facilities are requested by the Applicant or required by governmental authority, the Applicant or governmental authority will pay the additional costs if any.

ISSUED BY: S. W. Connally, Jr.

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Canceling Fifth Revised Sheet No. 4.24

[redacted]

6.2.6 OWNERSHIP OF UNDERGROUND FACILITIES. The Company will install, own, and maintain the electric distribution facilities up to the designated point of delivery for residential and commercial services up to and including 400A except as otherwise stated. Any payment made by the Applicant under the provisions of these Rules will not convey to the Applicant any rights of ownership. The Applicant may, subject to a contractual agreement with the Company, construct and install a portion of the underground distribution facilities provided:

(a) such work meets the Company's construction standards;

(b) the Company will own and maintain the completed distribution facilities;

(c) such agreement is not expected to cause the general body of ratepayers to incur greater costs;

(d) the Applicant agrees to pay Gulf Power Company's current applicable Engineering and Supervision rate associated with the estimate of work to be performed by the Applicant. This amount represents the cost of Gulf's engineering time to review and inspect the Applicant's work.

(e) the Applicant agrees to rectify any deficiencies found by Gulf Power Company prior to the connection of any customers to the underground electric distribution system or the connection of the underground electric distribution facilities to Gulf Power Company's distribution system. Furthermore, the deficiencies must be corrected in a timely manner or Gulf shall construct the system improvement using overhead facilities and the Applicant will have to pay the cost of such improvement and the cost of its removal before the corrected underground facilities will be connected.

6.2.7 RIGHTS OF WAY AND EASEMENTS.

(a) General Requirements. The Company shall construct, own, operate, and maintain distribution facilities only along easements, public streets, roads, and highways which the Company has the legal right to occupy, and on public lands and private property across which rights of way and easements satisfactory to the Company may be obtained without condemnation or cost to the Company.

(b) Scheduling, Clearing, and Grading. Rights of way and easements suitable to the Company must be furnished by the Applicant in reasonable time to meet service requirements, and must be cleared of trees, tree stumps, paving and other obstructions, staked to show property lines and final grade, and must be graded to within six (6) inches of final grade by the Applicant before the Company will commence construction, all at no charge to the Company. Such clearing and grading must be maintained by the Applicant during construction by the Company. Grade stakes must be provided at transformer locations.

Should paving, grass, landscaping, or sprinkler systems be installed prior to the construction of the underground distribution facilities, the Applicant shall pay the added costs of trenching, backfilling, and restoring the paving, grass, landscaping, and sprinkler systems to their original condition.

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6.3.2 (continued)

(c) The above charges are based upon arrangement of distribution facilities that will permit serving the local single-phase underground distribution system within the subdivision from existing overhead feeder mains. If the feeder mains or other three-phase facilities within the subdivision are deemed necessary by the Company to provide and/or maintain adequate service and are required by the Applicant or governmental agency to be installed underground, the Applicant shall pay the Company the estimated cost differential between the underground feeder mains, or other three-phase facilities and the equivalent overhead facilities.

6.3.3 FACILITIES TO BE UNDERGROUND. All service laterals and secondary and single phase primary conductors shall be underground. Appurtenances such as transformers, pedestal-mounted terminals, switching equipment, and meter cabinets may be placed above ground. Feeder mains required within a subdivision may be overhead if the Applicant and the Company determine that the additional cost of underground is not justified for that particular location, unless otherwise required by governmental authority, in which case the differential cost will be borne by the Applicant or governmental authority.

6.3.4 POINT OF DELIVERY. The point of delivery to the building shall be determined by the Company and normally will be at the point of the building nearest the point at which the underground secondary system is available to the property to be served. If the point of delivery on any building is more than fifty (50) feet in length from the available secondary system (seventy [70] feet for low density subdivisions), then the Applicant may be required to make additional payment for the excess length.

ISSUED BY: S.W. Connally, Jr.

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Eighth Revised Sheet No. 4.27
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6.3.5 LOCATION OF METER AND SOCKET & SERVICE ENTRANCE FACILITIES. The Applicant shall install a meter socket and suitable service entrance facilities at the point designated by the Company in accordance with the Company's specifications. Service conductors shall be installed, where possible, in a direct line to the point of delivery.

6.3.6 DEVELOPMENT OF SUBDIVISIONS. The above charges are based on reasonably full and timely use of the land being developed. Where the Company is required to construct underground electric facilities through a section or sections of the subdivision or development where, in the opinion of the Company, service will not be required for at least two years, the Company may require a deposit from the Applicant before construction is commenced. This deposit, to guarantee performance, will be based on the estimated total cost of such facilities rather than the differential cost. The amount of the deposit, without interest, in excess of any charges for underground service will be returned to the applicant on a pro-rata basis at quarterly intervals on the basis of installations to new customers. Any portion of such deposit remaining unrefunded, after five years from the date the Company is first ready to render service from the extension, will be retained by the Company.

6.4 UNDERGROUND DISTRIBUTION TO MULTIPLE-OCCUPANCY RESIDENTIAL BUILDINGS

6.4.1 AVAILABILITY. After receipt of proper application and compliance by the Applicant with applicable Company rules and procedures, the Company will install underground distribution facilities within that tract of land upon which multiple-occupancy residential buildings containing five (5) or more separate dwelling units will be constructed.

6.4.2 CONTRIBUTION BY APPLICANT. Service for new multiple-occupancy residential buildings will be constructed underground within the property to be served to the point of delivery at or near the building by the Company at no charge to the Applicant, provided the Company is free to construct its service extension or extensions in the most economical manner and reasonably full use is made of the tract of land upon which the multiple-occupancy buildings will be constructed. The Applicant must pay a cost differential for any non-residential service such as a pool or office building if such service is not ganged with other single phase residential services.

6.4.3 METER SOCKETS AND SERVICE ENTRANCE FACILITIES. The Applicant shall install service entrance facilities including meter sockets or suitable facilities for installation of the Company's meters at a location suitable to the Company. Meter sockets of facilities for installation of the Company's meters shall be a type and manufacture approved by the Company.

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Tenth Revised Sheet No. 4.28.1
Canceling Ninth Revised Sheet No. 4.28.1

[redacted]	[redacted]

6.5.3 (continued)

An Applicant desiring the Company to proceed with construction of the underground facilities described in a binding cost estimate may enter into a contract with the Company based on said estimate on or before the 180th day following Applicant's receipt of the estimate. So long as the contract is entered into by such date, the contract shall provide that the charges the Applicant is obligated to pay for installation of the underground facilities will not exceed 110 percent of the amount set forth in the binding estimate. So long as said contract is entered into by the date specified above, it shall further provide that the total charges the Applicant is obligated to pay for installation of underground facilities determined as set forth in section 6.5.4 below shall be reduced by the amount of the posted deposit associated with the binding cost estimate.

6.5.4 CONTRIBUTION BY APPLICANT. Prior to the installation of underground facilities covered by this subpart, the Applicant and the Company must enter into a contractual agreement setting forth the terms and conditions of the installation. The charge to be paid by the Applicant for underground facilities pursuant to the contractual agreement shall be determined as follows:

The cost of construction of the underground distribution facilities including the construction cost of the underground service lateral(s) to the meter(s) of the customer(s) and the net present value of the operating cost over the expected life of the underground facilities;

plus (if applicable) the estimated remaining book value of any existing facilities to be removed as part of the conversion of existing overhead facilities to underground, less the estimated net salvage value of the facilities to be removed;

minus the estimated construction cost to build new overhead facilities including the service drop(s) to the meter(s) of the customer(s) and the net present value of the operating cost over the expected life of the overhead facilities.

If the installation of the underground facilities is made pursuant to a contractual agreement based on a binding cost estimate received by the Applicant no more than 180 days prior to the date of the contractual agreement, the provisions of section 6.5.3 shall limit and modify the contribution to be paid by the Applicant for underground facilities.

6.5.5 METER SOCKETS AND SERVICE ENTRANCE FACILITIES. The Applicant shall install service entrance facilities including meter sockets or suitable facilities for installation of the Company's meters at a location suitable to the Company. Meter sockets or facilities for installation of the Company's meters shall be of a type and manufacture approved by the Company.

6.5.6 UNDERGROUND SECONDARY LATERAL SERVICE IN AN OVERHEAD RESIDENTIAL OR COMMERCIAL AREA. When requested by a residential or commercial Applicant, the Company will install, own, and maintain an underground secondary service lateral from its overhead facilities to the Applicant's point of delivery. The Applicant shall install a meter socket and suitable service entrance facilities at the point designated by the Company in accordance with the Company's specification. Prior to such installation, the Applicant and the Company will enter into an agreement outlining the terms and conditions of the installation, and the Applicant will be required to pay the Company in advance the cost differential between an overhead service and an underground service. The Applicant may participate in the process by trenching and installing the duct and/or providing the duct.

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GULF POWER
A SOUTHERN COMPANY

Section No. VI
Twenty-Ninth Revised Sheet No. 6.2
Canceling Twenty-Eighth Revised Sheet No. 6.2

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Designation	URSC	Classification	Sheet No.
RSVP	RS1	Residential Service Variable Pricing (Optional)	6.75
SP		Surge Protection	6.79
RTP		Real Time Pricing	6.80
CIS		Commercial/Industrial Service (Optional Rider)	6.84
BERS		Building Energy Rating System (BERS)	6.87
PV		Rate Rider PV - Photovoltaics (Optional Rider)	6.89
MBFC		Military Base Facilities Charge (Optional Rider)	6.91
LBIR		Large Business Incentive Rider (Optional Rider)	6.92
SBIR		Small Business Incentive Rider (Optional Rider)	6.94

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GULF POWER
A SOUTHERN COMPANY

Section No. VI
Thirtieth Revised Sheet No. 6.3
Canceling Twenty-Ninth Revised Sheet No. 6.3

RATE SCHEDULE RS
RESIDENTIAL SERVICE
URSC: RS

[redacted]

AVAILABILITY:

Available throughout the entire territory served by the Company.

APPLICABILITY:

Applicable for service used for domestic purposes at an individually metered dwelling unit suitable for year-round family occupancy containing full kitchen facilities and to commonly-owned facilities in condominium and cooperative apartment buildings. Garages, pools, pumps, boat dock, etc., on the same premise as the dwelling unit are included if all such service is for personal use. Service provided hereunder shall not be shared with or resold to others.

CHARACTER OF SERVICE:

Available for single phase service from local distribution lines of the Company's system at nominal secondary voltage of 120/240 volts.

RATES:

Base Charge:	$0.60 per day
Energy-Demand Charge:	4.884¢ per kWh

MINIMUM BILL:

In consideration of the readiness of the Company to furnish such service, a monthly minimum charge will be made of not less than the Base Charge.

DEPOSIT:

A deposit amounting to twice the estimated average monthly bill may be required before service is connected at designated premises. The deposit may be applied to any final bills against the Customer for service.

ISSUED BY: S.W. Connally, Jr.

GULF POWER
A SOUTHERN COMPANY

Section No. VI
Twenty-Fourth Revised Sheet No. 6.5
Canceling Twenty-Third Revised Sheet No. 6.5

RATE SCHEDULE GS
GENERAL SERVICE – NON-DEMAND
URSC: GS

[redacted]

AVAILABILITY:

Available throughout the entire territory served by the Company.

APPLICABILITY:

Applicable for general lighting and power service covering the entire electrical requirements of any Customer with a demand of less than 25 kW except for service to which another Rate Schedule is applicable. Service to two or more premises shall not be combined nor shall service furnished hereunder be shared with or resold to others. All service shall be taken at the same voltage and from a single delivery point.

CHARACTER OF SERVICE:

The delivery voltage to the Customer shall be the voltage of the available distribution lines of the Company for the locality in which service is to be rendered. Three phase service may be furnished at the request of the Customer subject to the Rules and Regulations of the Company which govern the extension of three phase service.

MONTHLY RATES:

Base Charge:	$21.00
Energy-Demand Charge:	5.300¢ per kWh

MINIMUM MONTHLY BILLS:

In consideration of the readiness of the Company to furnish such service, no monthly bill will be rendered for less than the Base Charge.

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GULF POWER
A SOUTHERN COMPANY

Section No. VI
Twenty-Third Revised Sheet No. 6.7
Canceling Twenty-Second Revised Sheet No. 6.7

RATE SCHEDULE GSD
GENERAL SERVICE - DEMAND
URSC: GSD

[redacted]

AVAILABILITY:

Available throughout the entire territory served by the Company.

APPLICABILITY:

Applicable for commercial, industrial, or institutional general service on an annual basis covering the entire electrical requirements of any Customer whose highest actual measured demand is not more than four hundred ninety-nine (499) kilowatts. Service to two or more premises shall not be combined nor shall service furnished hereunder be shared with or resold to others. All service shall be taken at the same voltage, from a single delivery point, and shall be measured by a single meter.

CHARACTER OF SERVICE:

The delivery voltage to the Customer shall be the voltage of the available secondary distribution lines of the Company for the locality in which service is to be rendered. Three phase service may be furnished at the request of the Customer subject to the Rules and Regulations of the Company which govern the extension of the three phase service.

MONTHLY RATES:

Base Charge:	$44.00
Demand Charge:	$6.84 per kW of billing demand
Energy Charge:	1.749¢ per kWh

MINIMUM MONTHLY BILLS:

In consideration of the readiness of the Company to furnish such service, no monthly bill will be rendered for less than the Base Charge plus the Demand Charge.

ISSUED BY: S. W. Connally, Jr.

GULF POWER
A SOUTHERN COMPANY

Section No. VI
Twenty-First Revised Sheet No. 6.8
Canceling Twentieth Revised Sheet No. 6.8

(Continued from Rate Schedule GSD, Sheet No. 6.7)

DETERMINATION OF BILLING DEMAND:

The kilowatt (kW) billing demand for billing purposes shall be the Customer's maximum integrated fifteen (15) minute demand to the nearest kilowatt (kW) during each service month.

REACTIVE DEMAND CHARGE:

When the capacity required to be maintained is one-hundred (100) kilowatts or more, at the option of the Company, the monthly bill calculated at the above rates may be increased in the amount of $1.00 per kvar for all over 0.48432 kilovars per kilowatt (90% power factor). The kilovars to which this adjustment shall apply shall be the monthly maximum measured kilovar demand or may be calculated as the square root of the difference between the square of the maximum monthly measured kVA demand and the square of the maximum monthly measured kW demand.

TRANSFORMER OWNERSHIP DISCOUNT AND PRIMARY METERING VOLTAGE DISCOUNTS:

When the Company renders service under this Rate Schedule at the local primary distribution voltage and any transformers required are furnished by the Customer, the Monthly Rate will be subject to a discount of thirty-nine (39) cents per kW of the Customer's billing demand as determined above, and an additional discount of one percent (1%) of the Energy Charge and one percent (1%) of the Demand Charge; however, such deduction shall not reduce the minimum monthly bill specified above.

TERM OF CONTRACT:

Service under this Schedule shall be for a period of not less than one year and thereafter from year to year until terminated by three (3) months' written notice by either party to the other.

DEPOSIT:

A deposit amounting to twice the estimated average monthly bill may be required before service is connected at designated premises. The deposit may be applied to any final bills against the Customer for service.

ISSUED BY: S. W. Connally, Jr.

GULF POWER
A SOUTHERN COMPANY

Section No. VI
Twenty-Sixth Revised Sheet No. 6.10
Canceling Twenty-Fifth Revised Sheet No. 6.10

RATE SCHEDULE LP
LARGE POWER SERVICE
URSC: GSLD

[redacted]

AVAILABILITY:

Available throughout the entire territory served by the transmission system of the Company.

APPLICABILITY:

Applicable for three phase general service on an annual basis covering the entire electrical requirements of any Customer. Service to two or more premises shall not be combined nor shall service furnished hereunder be shared with or resold to others. All service shall be taken at the same voltage, from a single delivery point, and shall be measured by a single meter.

CHARACTER OF SERVICE:

The delivery voltage to the Customer shall be the voltage of the available secondary distribution lines of the Company for the locality in which service is to be rendered.

MONTHLY RATES:

Base Charge:	$250.00
Demand Charge:	$12.23 per kW of billing demand
Energy Charge:	0.934¢ per kWh

MINIMUM MONTHLY BILLS:

In consideration of the readiness of the Company to furnish such service, no monthly bill will be rendered for less than the Base Charge plus the Demand Charge.

ISSUED BY: S. W. Connally, Jr.

GULF POWER
A SOUTHERN COMPANY

Section No. VI
Twenty-Fifth Revised Sheet No. 6.11
Canceling Twenty-Fourth Revised Sheet No. 6.11

(Continued from Rate Schedule LP, Sheet No. 6.10)

DETERMINATION OF BILLING DEMAND:

The kilowatt (kW) billing demand for billing purposes shall be the Customer's maximum integrated fifteen (15) minute demand to the nearest kilowatt (kW) during each service month.

REACTIVE DEMAND CHARGE:

The monthly bill calculated at the above rates shall also be increased in the amount of $1.00 per kvar for all over 0.48432 kilovars per kilowatt (90% power factor). The kilovars to which this adjustment shall apply shall be the monthly maximum measured kilovar demand or may be calculated as the square root of the difference between the square of the maximum monthly measured kVA demand and the square of the maximum monthly measured kW demand.

TRANSFORMER OWNERSHIP DISCOUNT AND PRIMARY METERING VOLTAGE DISCOUNTS:

When the Company renders service under this Rate Schedule at the local primary distribution voltage and any transformers required are furnished by the Customer, the Monthly Rate will be subject to a discount of fifty-five (55) cents per month per kilowatt (kW) of the Customer's billing demand as determined above, and an additional discount of one percent (1%) of the Energy Charge and one percent (1%) of the Demand Charge; however, such deduction shall not reduce the minimum monthly bill specified above.

TRANSFORMER OWNERSHIP DISCOUNT AND TRANSMISSION METERING VOLTAGE DISCOUNTS:

When the Company renders service under this Rate Schedule from an available transmission line of 46,000 volts or higher and the Customer furnishes, operates and maintains the complete step-down transformer substation necessary to receive and use such service the Monthly Rate will be subject to a discount of seventy-eight (78) cents per month per kilowatt (kW) of the Customer's billing demand as determined above, and an additional discount of two percent (2%) of the Energy Charge and two percent (2%) of the Demand Charge; however, such deduction shall not reduce the minimum monthly bill specified above.

DEPOSIT:

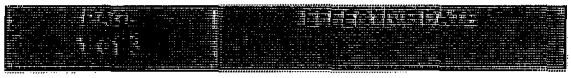
A deposit amounting to twice the estimated average monthly bill may be required before service is connected at designated premises. The deposit may be applied to any final bills against the Customer for service.

ISSUED BY: S. W. Connally, Jr.

GULF POWER
A SOUTHERN COMPANY

Section No. VI
Twenty-Second Revised Sheet No. 6.13
Canceling Twenty-First Revised Sheet No. 6.13

RATE SCHEDULE PX
LARGE HIGH LOAD FACTOR POWER SERVICE
URSC: GSLD1



AVAILABILITY:

Available throughout the entire territory served by the transmission system of the Company.

APPLICABILITY:

Applicable for three phase lighting and power service to any Customer whose actual measured demand is not less than 7,500 kilowatts (kW), with an annual load factor of not less than seventy-five percent (75%). Service to two or more premises shall not be combined nor shall service furnished hereunder be shared with or resold to others. All service shall be taken at the same voltage and from a single delivery point, and shall be measured by a single meter.

CHARACTER OF SERVICE:

The delivery voltage to the Customer shall be the standard secondary voltage of the Company's transformers supplied from the transmission lines of the Company.

MONTHLY RATES:

Base Charge:	$743.22
Demand Charge:	$10.85 per kW of billing demand
Energy Charge:	0.399¢ per kWh

MINIMUM MONTHLY BILL:

In the event the Customer's annual load factor for the current and preceding eleven months is less than 75% and in consideration of the readiness of the Company to furnish such service, the minimum monthly bill shall not be less than the Base Charge plus $13.03 per kW of billing demand.

ISSUED BY: S.W. Connally, Jr.

GULF POWER
A SOUTHERN COMPANY

Section No. VI
Twenty-Second Revised Sheet No. 6.16
Canceling Twenty-First Revised Sheet No. 6.16

RATE SCHEDULE OS
OUTDOOR SERVICE
URSC: SL, OL, OL1, OL2

[redacted]

AVAILABILITY:

Available throughout the entire territory served by the Company.

OS-I/II STREET, ROADWAY, AND GENERAL AREA LIGHTING

APPLICABILITY:

Applicable for street, roadway, and general area lighting service under the provisions of the Company's standard contract for such service. Service hereunder includes power supply and may include lamp renewals and regular maintenance.

LIMITATION OF SERVICE:

Company-owned fixtures will be mounted on Company-owned poles of the Company's distribution system. Customer-owned fixtures will be mounted on Customer-owned poles, of a standard type and design, permitting service and maintenance at no abnormal cost to the Company.

MONTHLY RATES:
High Pressure Sodium Vapor

Initial Lamp Rating (Lumen)	Desc.	Lamp Wattage	Line Wattage	Est. kWh **	Fixture Charge	Maint. Charge	Energy Charge ***	Total Charge
5400*	Open Bottom	70	84	29	$3.08	$1.66	$0.71	$5.45
8800	Open Bottom	100	120	41	$2.63	$1.50	$1.00	$5.13
8800	Open Bottom w/Shield	100	120	41	$3.62	$1.77	$1.00	$6.39
8800	Acorn	100	120	41	$13.14	$4.43	$1.00	$18.57
8800	Colonial	100	120	41	$3.54	$1.74	$1.00	$6.28
8800	English Coach	100	120	41	$14.34	$4.76	$1.00	$20.10
8800	Destin Single	100	120	41	$24.67	$7.65	$1.00	$33.32
17600	Destin Double	200	240	82	$49.20	$14.76	$2.01	$65.97
5400*	Cobrahead	70	84	29	$4.32	$2.00	$0.71	$7.03
8800	Cobrahead	100	120	41	$3.62	$1.77	$1.00	$6.39
20000*	Cobrahead	200	233	80	$4.98	$2.17	$1.96	$9.11
25000	Cobrahead	250	292	100	$4.84	$2.14	$2.45	$9.43
46000	Cobrahead	400	477	164	$5.10	$2.20	$4.01	$11.31
8800	Cutoff Cobrahead	100	120	41	$4.00	$1.87	$1.00	$6.87
25000	Cutoff Cobrahead	250	292	100	$4.90	$2.16	$2.45	$9.51
46000	Cutoff Cobrahead	400	477	164	$5.12	$2.20	$4.01	$11.33
25000	Bracket Mount CIS	250	292	100	$11.23	$3.92	$2.45	$17.60
25000	Tenon Top CIS	250	292	100	$11.23	$3.92	$2.45	$17.60

ISSUED BY: S. W. Connally, Jr.

GULF POWER
A SOUTHERN COMPANY

Section No. VI
Thirty-Fifth Revised Sheet No. 6.16.1
Canceling Thirty-Fourth Revised Sheet No. 6.16.1

(Continued from Rate Schedule OS, Sheet No. 6.16)

High Pressure Sodium Vapor (continued)

Initial Lamp Rating (Lumen)	Desc.	Lamp Wattage	Line Wattage	Est. kWh **	Fixture Charge	Maint. Charge	Energy Charge ***	Total Charge
46000	Bracket Mount CIS	400	468	161	$11.94	$4.11	$3.94	$19.99
20000*	Small ORL	200	233	80	$11.50	$3.98	$1.96	$17.44
25000	Small ORL	250	292	100	$11.07	$3.87	$2.45	$17.39
46000	Small ORL	400	477	164	$11.59	$4.01	$4.01	$19.61
20000*	Large ORL	200	233	80	$18.73	$5.99	$1.96	$26.68
46000*	Large ORL	400	477	164	$21.10	$6.66	$4.01	$31.77
46000	Shoebox	400	477	164	$9.67	$3.48	$4.01	$17.16
16000	Directional	150	197	68	$5.43	$2.26	$1.66	$9.35
20000*	Directional	200	233	80	$7.85	$2.98	$1.96	$12.79
46000	Directional	400	477	164	$5.83	$2.41	$4.01	$12.25
125000	Large Flood	1000	1105	379	$9.26	$3.55	$9.28	$22.09

Metal Halide

Initial Lamp Rating (Lumen)	Desc.	Lamp Wattage	Line Wattage	Est. kWh **	Fixture Charge	Maint. Charge	Energy Charge ***	Total Charge
12000	Acorn	175	210	72	$13.27	$5.58	$1.76	$20.61
12000	Colonial	175	210	72	$3.67	$2.92	$1.76	$8.35
12000	English Coach	175	210	72	$14.47	$5.92	$1.76	$22.15
12000	Destin Single	175	210	72	$24.80	$8.81	$1.76	$35.37
24000	Destin Double	350	420	144	$49.45	$16.47	$3.53	$69.45
32000	Small Flood	400	476	163	$5.96	$2.58	$3.99	$12.53
32000	Small Parking Lot	400	476	163	$11.01	$4.00	$3.99	$19.00
100000	Large Flood	1000	1100	378	$8.55	$5.12	$9.25	$22.92
100000	Large Parking Lot	1000	1100	378	$19.01	$7.09	$9.25	$35.35

Metal Halide Pulse Start

Initial Lamp Rating (Lumen)	Desc.	Lamp Wattage	Line Wattage	Est. kWh **	Fixture Charge	Maint. Charge	Energy Charge ***	Total Charge
13000	Acorn	150	190	65	$15.05	$5.42	$1.59	$22.06
13000	Colonial	150	190	65	$4.69	$2.55	$1.59	$8.83
13000	English Coach	150	190	65	$15.39	$5.53	$1.59	$22.51
13000	Destin Single	150	190	65	$32.64	$10.35	$1.59	$44.58
26000	Destin Double	300	380	130	$65.14	$19.88	$3.18	$88.20
33000	Small Flood	350	400	137	$6.68	$3.29	$3.35	$13.32
33000	Shoebox	350	400	137	$7.98	$3.66	$3.35	$14.99
68000	Flood	750	840	288	$6.88	$5.53	$7.05	$19.46

ISSUED BY: S. W. Connally, Jr.

GULF POWER
A SOUTHERN COMPANY

Section No. VI
Twenty-Fifth Revised Sheet No. 6.17
Canceling Twenty-Fourth Revised Sheet No. 6.17

PAGE	EFFECTIVE DATE
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(Continued from Rate Schedule OS, Sheet No. 6.16.1)

Combined High Pressure Sodium/Metal Halide

Initial Lamp Rating (Lumen)	Desc.	Lamp Wattage	Line Wattage	Est. kWh **	Fixture Charge	Maint. Charge	Energy Charge ***	Total Charge
20800	Destin Combo	275	330	113	$49.32	$16.26	$2.77	$68.35

Combined High Pressure Sodium/Metal Halide Pulse Start

Initial Lamp Rating (Lumen)	Desc.	Lamp Wattage	Line Wattage	Est. kWh **	Fixture Charge	Maint. Charge	Energy Charge ***	Total Charge
21800	Destin Combo PS	250	310	106	$57.17	$17.59	$2.60	$77.36

LED

Nominal Delivered Lumen	Desc.	Lamp Wattage	Line Wattage	Est. kWh **	Fixture Charge	Maint. Charge	Energy Charge ***	Total Charge
3776	Acorn	75	75	26	$17.66	$9.12	$0.64	$27.42
4440	Street Light	72	72	25	$13.71	$4.69	$0.61	$19.01
2820	Acorn A5	56	56	19	$25.41	$7.86	$0.47	$33.74
5100	Cobrahead S2	73	73	25	$6.01	$3.92	$0.61	$10.54
10200	Cobrahead S3	135	135	46	$7.40	$4.52	$1.13	$13.05
6320	ATB071 S2/S3	71	71	24	$7.49	$5.10	$0.59	$13.18
9200	ATB1 105 S3	105	105	36	$10.95	$6.15	$0.88	$17.98
23240	ATB2 280 S4	280	280	96	$12.39	$7.15	$2.35	$21.89
7200	E132 A3	132	132	45	$27.42	$8.03	$1.10	$36.55
9600	E157 SAW	157	157	54	$18.56	$5.54	$1.32	$25.42
7377	WP9 A2/S2	140	140	48	$41.70	$13.82	$1.18	$56.70
7614	Destin Single	105	105	36	$32.05	$15.38	$0.88	$48.31
15228	Destin Double	210	210	72	$63.82	$30.53	$1.76	$96.11

ISSUED BY: S. W. Connally, Jr.

GULF POWER
A SOUTHERN COMPANY

Section No. VI
Twenty-Seventh Revised Sheet No. 6.18
Canceling Twenty-Sixth Revised Sheet No. 6.18

(Continued from Rate Schedule OS, Sheet No. 6.17)

Mercury Vapor
(Not Available for New Installations)

Initial Lamp Rating (Lumen)	Desc.	Lamp Wattage	Line Wattage	Est. kWh **	Fixture Charge	Maint. Charge	Energy Charge ***	Total Charge
7000*	Open Bottom	175	195	67	$2.14	$1.32	$1.64	$5.10
3200*	Cobrahead	100	114	39	$3.96	$1.86	$0.95	$6.77
7000*	Cobrahead	175	195	67	$3.60	$1.73	$1.64	$6.97
9400*	Cobrahead	250	277	95	$4.73	$2.11	$2.33	$9.17
17000*	Cobrahead	400	442	152	$5.16	$2.20	$3.72	$11.08
48000*	Cobrahead	1000	1084	372	$10.36	$3.82	$9.11	$23.29
17000*	Directional	400	474	163	$7.77	$2.94	$3.99	$14.70

* Not Available for New Installation.
** Estimated Monthly kWh = (Line Wattage x Annual Operating Hours)/(1000 x 12)
*** Energy Charge = 2.448¢/kWh x Estimated Monthly kWh Usage

ADDITIONAL FACILITIES CHARGES:

The above rates apply to lighting installations made on the Company's existing overhead distribution system. Any special or additional facilities, which may be installed at the Company's option, will be billed in addition to the above rates.

Charge for 13 ft. decorative concrete pole used only for decorative lights (Colonial, Acorn, or English Coach) $17.17.
Charge for 13 ft. decorative high gloss concrete pole used only for decorative lights. (Colonial, Acorn, or English Coach) $15.55.
Charge for 16 ft. decorative base aluminum pole with 6" Tenon used only for decorative lights (Destin Single or Double) $12.32.
Charge for 17 ft. decorative base aluminum pole used only for decorative lights (Colonial, Acorn, or English Coach) $17.99.
Charge for 20 ft. fiberglass pole used only for decorative lights (Colonial) $6.37.
Charge for 20 ft. (16 ft. mounting height) aluminum, round, tapered pole (Spun Tenon) $5.61.
Charge for 20 ft. (16 ft. mounting height) aluminum, round, tapered pole (Welded Tenon) $19.09.
Charge for 25 ft. (20 ft. mounting height) aluminum, round, tapered pole $19.95.
Charge for 30 ft. wood pole $4.12.
Charge for 30 ft. concrete pole $8.64.
Charge for 30 ft. fiberglass pole with concrete, anchor-based pedestal used primarily for the 100,000 Lumen Large Parking Lot fixture $40.91.
Charge for 30 ft. (25 ft. mounting height) aluminum, round, tapered pole $22.13.
Charge for 35 ft. concrete pole $12.59.
Charge for 35 ft. concrete pole (Tenon Top) $17.38.

ISSUED BY: S. W. Connally, Jr.

GULF POWER
A SOUTHERN COMPANY

Section No. VI
Twenty-Third Revised Sheet No. 6.19
Canceling Twenty-Second Revised Sheet No. 6.19

[redacted]

(Continued from Rate Schedule OS, Sheet No. 6.18)

ADDITIONAL FACILITIES CHARGES (continued):

Charge for 35 ft. wood pole $6.01.
Charge for 35 ft. (30 ft. mounting height) aluminum, round, tapered pole $24.78.
Charge for 40 ft. wood pole $7.38.
Charge for 45 ft. concrete pole (Tenon Top) $22.81.
Charge for single arm for Shoebox/Small Parking Lot fixture $2.39.
Charge for double arm for Shoebox/Small Parking Lot fixture $2.66.
Charge for triple arm for Shoebox/Small Parking Lot fixture $3.59.
Charge for quadruple arm for Shoebox/Small Parking Lot fixture $4.53.
Charge for Tenon Top adapter for 100,000 Lumen Large Parking Lot fixture $4.42.
Charge for optional 100 amp relay $24.72.
Charge for 25 kVA transformer (non-coastal) for 46,000 Lumen Shoebox, 32,000 Lumen Small Parking Lot, or 100,000 Lumen Large Parking Lot fixture(s) $34.21.
Charge for 25 kVA transformer (coastal) for 46,000 Lumen Shoebox, 32,000 Lumen Small Parking Lot, or 100,000 Lumen Large Parking Lot fixture(s) $48.75.

All other additional facilities shall be billed at 1.74% per month of the Company's cost. Such facilities may include, but are not limited to, additional overhead or underground wiring and special poles approved by the Company.

VANDALISM (WILLFUL DAMAGE):

The Customer will have the following three options on the second occurrence of vandalism (willful damage) to a Company fixture:

1. Pay (a) the total repair costs of the fixture or the original total installed cost of the fixture less any depreciation and salvage value plus the removal cost if the fixture cannot be repaired and (b) the total installed cost of a luminaire protective shield. If the fixture is not compatible with the shield, then the fixture will be replaced with either a compatible 100 watt or 250 watt cobrahead fixture,

2. Request that the damaged fixture be replaced with the same type of unshielded fixture. For this and any subsequent occurrence, the Customer will pay either (a) the total repair costs of the fixture or (b) the original total installed cost of the fixture less any depreciation and salvage value plus the removal cost if the fixture cannot be repaired, or

3. Discontinue the service to the fixture.

The Customer must notify the Company in writing of its selected option. The Customer may choose to pay the total installed cost of a luminaire protective shield after the first occurrence of vandalism (willful damage) to a Company fixture and save the costs incurred in 1(a) above.

ISSUED BY: S. W. Connally, Jr.

GULF POWER
A SOUTHERN COMPANY

Section No. VI
Twenty-Fourth Revised Sheet No. 6.20
Canceling Twenty-Third Revised Sheet No. 6.20

(Continued from Rate Schedule OS, Sheet No. 6.19)

MONTHLY RATES - CUSTOMER OWNED WITHOUT RELAMPING SERVICE AGREEMENT:

Customer-owned street, roadway, and general area lighting fixtures which conform to the specifications of Company-owned fixtures may receive energy at the appropriate charges for each size light above. Customer-owned street, roadway, and general area lighting systems which do not conform to specifications of the Company-owned fixtures shall be charged the monthly rate of 2.448¢/kWh of the estimated kWh usage of each unit. Customer-owned equipment must be approved in advance as to accessibility to be eligible to receive service. The Customer will provide all pole(s), fixture(s), lamp(s), photoelectric control(s), and circuit(s) up to the point of connection to the Company's supply lines (point of service), and an adequate support for the Company-owned service conductors. The Company will provide an overhead service drop from its existing secondary conductors to the point of service designated by the Company for Customer-owned lights. Underground service conductors will be installed in lieu of the overhead conductors at the Customer's request, and upon payment by the Customer of the installed cost of the underground conductors after allowance for the cost of equivalent overhead service conductors and any trenching and backfilling provided by the Customer. The distribution system shall serve no other electrical loads except the lighting equipment eligible for this rate.

MONTHLY RATES - CUSTOMER OWNED WITH RELAMPING SERVICE AGREEMENT:

The monthly rates set forth below cover both the electric service (if unmetered) and the replacement of lamps and photoelectric controls upon routine failure. Lamps or photoelectric controls damaged or destroyed due to vandalism or willful abuse are not covered by the agreement and will only be replaced at the Customer's expense. Customer-owned equipment must be approved in advance as to compatibility with Company-owned lamps and photoelectric controls and accessibility to be eligible to receive service. The Customer will provide all pole(s), fixture(s), initial lamp(s) and photoelectric control(s), and circuit(s) up to the point of connection to the Company's supply lines (point of service), and an adequate support for the Company-owned service conductors. The Company will provide an overhead service drop from its existing secondary conductors to the point of service designated by the Company for Customer-owned lights. Underground service conductors will be installed in lieu of the overhead conductors at the Customer's request, and upon payment by the Customer of the installed cost of the underground conductors after allowance for the cost of equivalent overhead service conductors and any trenching and backfilling provided by the Customer. The distribution system shall serve no other electrical loads except the lighting equipment eligible for this rate. The Customer remains responsible for all maintenance other than the replacement of lamps and photoelectric controls.

ISSUED BY: S.W. Connally, Jr.

GULF POWER
A SOUTHERN COMPANY

Section No. VI
Twenty-Fourth Revised Sheet No. 6.21
Canceling Twenty-Third Revised Sheet No. 6.21

[redacted]

(Continued from Rate Schedule OS, Sheet No. 6.20)

MONTHLY RATES - CUSTOMER OWNED WITH RELAMPING SERVICE AGREEMENT:

High Pressure Sodium Vapor

Initial Lamp Rating (Lumen)	Lamp Wattage	Line Wattage	Est. kWh **	Relamping Charge	Energy Charge ***	Total Charge
8800	100	120	41	$0.68	$1.00	$1.68
6000	150	197	68	$0.67	$1.66	$2.33
20000*	200	233	80	$0.69	$1.96	$2.65
25000	250	292	100	$0.70	$2.45	$3.15
46000	400	477	164	$0.69	$4.01	$4.70
125000	1000	1105	379	$0.88	$9.28	$10.16

Metal Halide

Initial Lamp Rating (Lumen)	Lamp Wattage	Line Wattage	Est. kWh **	Relamping Charge	Energy Charge ***	Total Charge
32000	400	476	163	$0.82	$3.99	$4.81

LED

Initial Lamp Rating (Lumen)	Lamp Wattage	Line Wattage	Est. kWh **	Relamping Charge	Energy Charge ***	Total Charge
4440	72	72	25	$0.77	$0.61	$1.38

* Not Available for New Installation
** Estimated Monthly kWh = (Line Wattage x Annual Operating Hours)/(1000 x 12)
*** Energy Charge = 2.448¢/kWh x Estimated Monthly kWh Usage

The Total Charge shown above is for an unmetered fixture. If the service is metered, there will be no Energy Charge billed under this rate.

ADDITIONAL FACILITIES CHARGES FOR CUSTOMER OWNED:

Any special or additional facilities, which may be installed at the Company's option, will be billed in addition to the above Customer-owned rates.

Charge for 35 ft. wood pole $6.01.

All other additional facilities shall be billed at 1.74 percent per month of the Company's cost.

ISSUED BY: S. W Connally, Jr.

GULF POWER
A SOUTHERN COMPANY

Section No. VI
Eighteenth Revised Sheet No. 6.22
Canceling Seventeenth Revised Sheet No. 6.22

[redacted]

(Continued from Rate Schedule OS, Sheet No. 6.21)

PROVISION FOR UP FRONT PAYMENT OF ADDITIONAL FACILITIES:

At the Customer's option, the cost of the additional facilities may be paid up front in lieu of a monthly charge. Should the Customer choose this method of payment, the amount will be the Company's total installed cost for these additional facilities for overhead or underground distribution electric service. The Company will retain ownership of these additional facilities.

The useful life of the pole(s) is 30 years from the installation date; and the useful life of the wire, eyebolts, and other miscellaneous additional facilities is 15 years from the installation date. If the pole(s), wire, eyebolts and/or other miscellaneous additional facilities must be changed out prior to this date, the facilities will be changed out at no cost to the Customer; and the billing of these facilities will remain as is. However, if any of these facilities have to be changed out on or after this date, then the Customer will have the option of one of three billing methods for the additional facilities that are replaced: (1) paying up front for the total installed cost of the replacement of the additional facilities, (2) paying a monthly charge as provided in the tariff, or (3) discontinuing the unmetered electric service.

PROVISION FOR UP FRONT PAYMENT OF FIXTURES:

At the Customer's option, the cost of the fixture(s) may be paid up front in lieu of paying the monthly Total Charge of the fixture(s). Should the Customer choose this method of payment, the amount will be the Company's total installed cost for the fixture(s). The Company will retain ownership of the fixture(s) and will provide for any routine maintenance. On a monthly basis, the Customer will pay only the Maintenance and Energy Charges for the fixture(s) in lieu of the total of the Fixture, Maintenance, and Energy Charges.

The useful life of the fixture(s) is 15 years from the installation date. If the fixture(s) fails prior to this date, the fixture(s) will be changed out at no cost to the Customer; and the billing of fixture(s) will remain as is. However, if the fixture(s) fails on or after this date, then the Customer will have the option of one of three billing methods for the fixture(s) that is replaced: (1) paying up front for the total installed cost of the replacement of the fixture(s) and continuing to pay on a monthly basis the Maintenance and Energy Charges for the fixture(s), (2) paying the monthly Total Charge of the fixture(s) as provided in the tariff, or (3) discontinuing the unmetered electric service.

PROVISION FOR CHANGING TO DIFFERENT FIXTURE BEFORE CONTRACT EXPIRES:

The Company will change out a fixture(s) currently being billed to a customer to a different type of fixture(s) at no cost after the expiration of the initial contract term. If a Customer requests that the change out be made prior to the end of the initial contract term, the Customer will be billed labor and overhead costs for the removal of the old fixture or parts necessary for the conversion (lamp, ballast, etc.) and the installation of the new fixture or parts necessary for the conversion (lamp, ballast, etc.). The Customer will then begin paying the price in the tariff applicable to the new fixture(s) that was installed.

ISSUED BY: S. W. Connally, Jr.

GULF POWER
A SOUTHERN COMPANY

Section No. VI
Nineteenth Revised Sheet No. 6.23
Canceling Eighteenth Revised Sheet No. 6.23

PAGE	EFFECTIVE DATE
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(Continued from Rate Schedule OS, Sheet No. 6.22)

OS-III. OTHER OUTDOOR SERVICE (OL1)

Other outdoor service for Customer-owned facilities with fixed wattage loads operating continuously throughout the billing period such as, but not limited to, traffic signals and cable television amplifiers shall be billed according to the monthly rate below:

4.614 cents per kWh for all kWh

The estimated annual kWh usage shall be determined by multiplying the annual operation hours times the maximum demand. The monthly kWh usage will be one-twelfth (1/12) of the estimated annual kWh usage. Maximum demand shall be the total number of kilowatts connected at any one time. At the option of the Company service rendered under this section may be metered and billed under the applicable General Service rate schedule. Minimum Monthly bill shall be $1.00 per service connection.

TERM OF CONTRACT (OS-I/II, OS-III):

Service under this Rate Schedule shall be for an initial period of not less than three (3) years and shall remain until terminated by notice to either party by the other. When additional facilities are required, the Company may require a contract for a longer initial period. There is no term of contract for rate OS-III.

DEPOSIT (OS-I/II, OS-III):

A deposit amounting to not over one-half the billing for the initial contract period may be required before service is connected. The deposit may be applied to any final bills against the Customer for service.

ISSUED BY: S. W. Connally, Jr.

GULF POWER
A SOUTHERN COMPANY

Section No. VI
Ninth Revised Sheet No. 6.42
Canceling Eighth Revised Sheet No. 6.42

RATE SCHEDULE GSTOU
GENERAL SERVICE TIME-OF-USE CONSERVATION (OPTIONAL SCHEDULE)

URSC: GSTOU

[redacted]

AVAILABILITY:

Available on a first come - first serve basis subject to meter availability throughout the entire territory served by the Company.

APPLICABILITY:

Applicable as an option to Rate Schedule GSD for general service on an annual basis covering the entire electrical requirements of any Customer whose highest actual measured demand is not more than four hundred ninety-nine (499) kilowatts. Service to two or more premises shall not be combined nor shall service furnished hereunder be shared with or resold to others. All service shall be taken at the same voltage, from a single delivery point, and shall be measured by a single meter.

CHARACTER OF SERVICE:

The delivery voltage to the Customer shall be the voltage of the available secondary distribution lines of the Company for the locality in which service is to be rendered. Three phase service may be furnished at the request of the Customer subject to the Rules and Regulations of the Company which govern the extension of the three phase service.

MONTHLY RATES:

Base Charge: $44.00

Energy Charges:

Summer – June through September:

On-Peak	18.691¢ per kWh
Intermediate	6.978¢ per kWh
Off-Peak	2.902¢ per kWh

October through May:

All hours	4.062¢ per kWh

ISSUED BY: S. W. Connally, Jr.

GULF POWER
A SOUTHERN COMPANY

Section No. VI
Fifth Revised Sheet No. 6.46
Canceling Fourth Revised Sheet No. 6.46

[redacted]

(Continued from Rate Schedule GSDT, Sheet No. 6.45)

MONTHLY RATES:

Base Charge:	$44.00
Demand Charge:	$3.24 per kW of maximum demand plus; $3.66 per kW of on-peak demand
Energy Charge:	1.749¢ per kWh

CRITICAL PEAK OPTION – Under this option, the Demand Charge shall be:

Demand Charge:	$3.24 per kW of maximum demand plus; $1.83 per kW of on-peak demand plus, $5.49 per kW of critical peak demand

MINIMUM MONTHLY BILLS:

In consideration of the readiness of the Company to furnish such service, no monthly bill will be rendered for less than the Base Charge plus the Demand Charge.

DETERMINATION OF THE ON-PEAK PERIOD:

The on-peak period for calendar months April through October is defined as being those hours between 12:00 p.m. and 9:00 p.m. Central Daylight Time/Central Standard Time, Monday through Friday.

The on-peak period for calendar months November through March is defined as being those hours between 6:00 a.m. and 10:00 a.m. and between 6:00 p.m. and 10:00 p.m. Central Standard Time/Central Daylight Time, Monday through Friday.

ISSUED BY: S. W. Connally, Jr.

GULF POWER
A SOUTHERN COMPANY

Section No. VI
Fourth Revised Sheet No. 6.48
Canceling Third Revised Sheet No. 6.48

[redacted]

(Continued from Rate Schedule GSDT, Sheet No. 6.47)

TRANSFORMER OWNERSHIP DISCOUNT AND PRIMARY METERING VOLTAGE DISCOUNTS:

When the Company renders service under this Rate Schedule at the local primary distribution voltage and any transformers required are furnished by the Customer, the Monthly Rate will be subject to a discount of thirty-nine (39) cents per kW of the Customer's Maximum Demand as determined above, and an additional discount of one percent (1%) of the Energy Charge and one percent (1%) of the Demand Charge; however, such deduction shall not reduce the minimum monthly bill specified above.

CRITICAL PEAK DEMAND NOTIFICATION

A customer electing the critical peak option will be notified of a critical peak period one business day prior to the beginning of the critical peak period event. The Company is not responsible for a customer's failure to receive and act upon the critical peak period. If a customer does not receive these notifications, it is the customer's responsibility to inform the Company so the notifications may be supplied.

TERM OF CONTRACT:

(1) Service under this Schedule shall be for a period of not less than one year and thereafter from year to year until terminated by three (3) months' written notice by either party to the other.

(2) The initial selection of this optional rate schedule by a Rate Schedule GSD Customer may be terminated at any time by written or personal notice from the Customer. After such termination, any subsequent selection of this option by the same Customer for service at the same premises shall have a term of contract as specified in (1) above.

ISSUED BY: S. W. Connally, Jr.

GULF POWER
A SOUTHERN COMPANY

Section No. VI
Fifth Revised Sheet No. 6.49
Canceling Fourth Revised Sheet No. 6.49

RATE SCHEDULE LPT
LARGE POWER SERVICE – TIME-OF-USE CONSERVATION (OPTIONAL SCHEDULE)

URSC: GSLDT

[redacted]

AVAILABILITY:

Available on a first come - first serve basis subject to meter availability throughout the entire territory served by the transmission system of the Company.

APPLICABILITY:

Applicable as an option to Rate Schedule LP for three phase general service on an annual basis covering the entire electrical requirements of any Customer. Service to two or more premises shall not be combined nor shall service furnished hereunder be shared with or resold to others. All service shall be taken at the same voltage, from a single delivery point, and shall be measured by a single meter. Customers taking service under Rate LPT may elect the critical peak option.

CHARACTER OF SERVICE:

The delivery voltage to the Customer shall be the voltage of the available secondary distribution lines of the Company for the locality in which service is to be rendered.

MONTHLY RATES:

Base Charge:	$250.00
Demand Charge:	$2.54 per kW of maximum demand plus; $9.84 per kW of on-peak demand
Energy Charge:	0.934¢ per kWh

ISSUED BY: S. W. Connally, Jr.

GULF POWER
A SOUTHERN COMPANY

Section No. VI
Third Revised Sheet No. 6.50
Canceling Second Sheet No. 6.50

(Continued from Rate Schedule LPT, Sheet No. 6.49)

CRITICAL PEAK OPTION –Under this option, the Demand Charge shall be:

Demand Charge:	$2.54 per kW of maximum demand plus; $4.92 per kW of on-peak demand plus, $14.76 per kW of critical peak demand

MINIMUM MONTHLY BILLS:

In consideration of the readiness of the Company to furnish such service, no monthly bill shall be rendered for less than the Base Charge plus the Demand Charge.

DETERMINATION OF THE ON-PEAK PERIOD:

The on-peak period for calendar months April through October is defined as being those hours between 12:00 p.m. and 9:00 p.m. Central Daylight Time/Central Standard Time, Monday through Friday.

The on-peak period for calendar months November through March is defined as being those hours between 6:00 a.m. and 10:00 a.m. and between 6:00 p.m. and 10:00 p.m. Central Standard Time/Central Daylight Time, Monday through Friday.

DETERMINATION OF THE OFF-PEAK PERIOD:

All hours not included above and all hours of the observed holidays of New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving, and Christmas are in the off-peak period.

DETERMINATION OF CRITICAL PEAK PERIOD:

A critical peak period may be designated at any time at the Company's discretion. The duration of any single critical peak period may range from 1 to 2 hours in length. The total number of hours designated as critical peak periods may not exceed 87 hours per year. The total number of critical peak periods may not exceed one per day, and may not exceed four per week. Conditions which may result in the designation of a critical peak period by the Company include, but are not limited to: (i) A temperature forecast for the Company's service area that is above 95°F or below 32°F; (ii) Real-Time-Prices that exceed certain thresholds; (iii) Projections of system peak loads that exceed certain thresholds.

ISSUED BY: S. W. Connally, Jr.

GULF POWER
A SOUTHERN COMPANY

Section No. VI
Third Revised Sheet No. 6.51
Canceling Second Revised Sheet No. 6.51

(Continued from Rate Schedule LPT, Sheet No. 6.50)

DETERMINATION OF BILLING DEMAND:

(a) Maximum Demand--The kilowatt (kW) billing demand for billing purposes shall be the Customer's maximum integrated 15 minute demand to the nearest kilowatt (kW) during each service month.

(b) On-Peak Demand--The kilowatt (kW) billing demand for billing purposes shall be the Customer's maximum integrated 15 minute demand to the nearest kilowatt (kW) during each service month as measured during the hours designated as on-peak.

(c) Critical Peak Demand – The kilowatt (kW) billing demand for billing purposes shall be the Customer's maximum integrated 15 minute demand to the nearest kilowatt (kW) during each service month as measured during the hours designated as critical peak.

REACTIVE DEMAND CHARGE:

The monthly bill calculated at the above rates may be increased in the amount of $1.00 per kvar for all over 0.48432 kilovars per kilowatt (90% power factor). The kilovars to which this adjustment shall apply shall be the monthly maximum measured kilovar demand or may be calculated as the square root of the difference between the square of the maximum monthly measured kVA demand and the square of the maximum monthly measured kW demand.

TRANSFORMER OWNERSHIP DISCOUNT AND PRIMARY METERING VOLTAGE DISCOUNTS:

When the Company renders service under this Rate Schedule at the local primary distribution voltage and any transformers required are furnished by the Customer, the Monthly Rate will be subject to a discount of fifty-five (55) cents per month per kilowatt (kW) of the Customer's highest billing demand as determined above, and an additional discount of one percent (1%) of the Energy Charge and one percent (1%) of the Demand Charge; however, such deduction shall not reduce the minimum monthly bill specified above.

ISSUED BY: S. W. Connally, Jr.

GULF POWER
A SOUTHERN COMPANY

Section No. VI
Third Revised Sheet No. 6.52
Canceling Second Revised Sheet No. 6.52

(Continued from Rate Schedule LPT, Sheet No. 6.51)

TRANSFORMER OWNERSHIP DISCOUNT AND TRANSMISSION METERING VOLTAGE DISCOUNTS:

When the Company renders service under this Rate Schedule from an available transmission line of 46,000 volts or higher and the Customer furnishes, operates, and maintains the complete step-down transformer substation necessary to receive and use such service, the Monthly Rate will be subject to a discount of seventy-eight (78) cents per month per kilowatt (kW) of the Customer's highest billing demand as determined above, and an additional discount of two percent (2%) of the Energy Charge and two percent (2%) of the Demand Charge; however, such deduction shall not reduce the minimum monthly bill specified above.

DEPOSIT:

A deposit amounting to twice the estimated average monthly bill may be required before service is connected at designated premises. The deposit may be applied to any final bills against the Customer for service.

CRITICAL PEAK DEMAND NOTIFICATION

A customer electing the critical peak option will be notified of a critical peak period one business day prior to the beginning of the critical peak period event. The Company is not responsible for a customer's failure to receive and act upon the critical peak period. If a customer does not receive these notifications, it is the customer's responsibility to inform the Company so the notifications may be supplied.

TERM OF CONTRACT:

(1) Service under this Schedule shall be for a period of not less than one year and thereafter from year to year until terminated by three (3) months' written notice by either party to the other.

(2) The initial selection of this rate schedule as an option by a Rate Schedule LP Customer may be terminated at any time by written or personal notice from the Customer. After such termination, any subsequent selection of this option by the same Customer for service at the same premises shall have a term of contract as specified in (1) above.

ISSUED BY: S. W. Connally, Jr.

GULF POWER
A SOUTHERN COMPANY

Section No. VI
Fifth Revised Sheet No. 6.53
Canceling Fourth Revised Sheet No. 6.53

RATE SCHEDULE PXT
LARGE HIGH LOAD FACTOR POWER SERVICE
TIME-OF-USE CONSERVATION
(OPTIONAL SCHEDULE)

URSC: GSLDT1

[redacted]

AVAILABILITY:

Available throughout the entire territory served by the transmission system of the Company.

APPLICABILITY:

Applicable as an option to Rate Schedule PX for three phase lighting and power service to any customer whose actual measured demand is not less than 7,500 kilowatts (kW), with an annual load factor of not less than seventy-five percent (75%). Service to two or more premises shall not be combined nor shall service furnished hereunder be shared with or resold to others. All service shall be taken at the same voltage and from a single delivery point, and shall be measured by a single meter.

CHARACTER OF SERVICE:

The delivery voltage to the Customer shall be the standard secondary voltage of the Company's transformers supplied from the transmission lines of the Company.

MONTHLY RATES:

Base Charge:	$743.22
Demand Charge:	$0.90 per kW of maximum demand plus; $10.07 per kW of on-peak demand
Energy Charge:	On-Peak and Off-Peak Period: 0.399¢ per kWh

ISSUED BY: S. W. Connally, Jr.

GULF POWER
A SOUTHERN COMPANY

Section No. VI
Fifth Revised Sheet No. 6.54
Canceling Fourth Revised Sheet No. 6.54

[redacted]

(Continued from Rate Schedule PXT, Sheet No. 6.53)

DETERMINATION OF THE ON-PEAK PERIOD:

The on-peak period for calendar months April through October is defined as being those hours between 12:00 p.m. and 9:00 p.m. Central Daylight Time/Central Standard Time, Monday through Friday.

The on-peak period for calendar months November through March is defined as being those hours between 6:00 a.m. and 10:00 a.m. and between 6:00 p.m. and 10:00 p.m. Central Standard Time/Central Daylight Time, Monday through Friday.

DETERMINATION OF THE OFF-PEAK PERIOD:

All hours not included above and all hours of the observed holidays of New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving, and Christmas are in the off-peak period.

MINIMUM MONTHLY BILLS:

In the event the Customer's annual load factor for the current and preceding eleven months is less than 75% and in consideration of the readiness of the Company to furnish such service, the minimum monthly bill shall not be less than the Base Charge plus $13.15 per kW of maximum billing demand.

DETERMINATION OF BILLING DEMAND:

(a) Maximum Demand--The kilowatt (kW) billing demand for billing purposes shall be the maximum measured kw demand integrated over any fifteen minute interval during the current bill month but not less than 7500 kW.

(b) On-Peak Demand--The kilowatt (kW) billing demand for billing purposes shall be the customer's maximum integrated 15 minute demand to the nearest kilowatt (kW) during each service month as measured during the hours designated as on-peak.

REACTIVE DEMAND CHARGE:

The monthly bill calculated at the above rates shall also be increased in the amount of $1.00 per kvar for all over 0.48432 kilovars per kilowatt (90% power factor). The kilovars to which this adjustment shall apply shall be the monthly maximum measured kilovar demand or may be calculated as the square root of the difference between the square of the maximum monthly measured kVA demand and the square of the maximum monthly measured kW demand.

ISSUED BY: S. W. Connally, Jr.

GULF POWER
A SOUTHERN COMPANY

Section No. VI
Fifth Revised Sheet No. 6.59
Canceling Fourth Revised Sheet No. 6.59

(Continued from Rate Schedule SBS, Sheet No. 6.58)

A Standby Service Customer will be billed for electric service in accordance with the following charges:

Contract Demand:	100 to 499 kW	500 to 7,499 kW	Above 7,499 kW
Base Charge:	$248.20	$248.20	$591.01
Demand Charge:			
Local Facilities Charge Per kW of BC and NC	$2.66	$2.35	$1.04
On-Peak Demand Charge: Per kW of On-Peak kW up to NC	$3.66	$9.84	$10.07
Plus the greater of:			
Reservation Charge: Per kW of BC or	$1.18	$1.18	$1.21
The Sum of the Daily On-Peak Standby Demand Charges: Per kW per day of On-Peak kW in excess of NC	$0.56	$0.56	$0.57
Energy Charge Per kWh:	3.460¢	3.460¢	3.460¢

Customers with zero (0) NC will not be subject to the On-Peak Demand Charge.

ISSUED BY: S. W. Connally, Jr

GULF POWER
A SOUTHERN COMPANY

Section No. VI
Third Revised Sheet No. 6.62
Canceling Second Revised Sheet No. 6.62

(Continued from Rate Schedule SBS, Sheet No. 6.61)

TRANSFORMER OWNERSHIP DISCOUNT AND PRIMARY METERING VOLTAGE DISCOUNTS:

When the Company renders service under this Rate Schedule at the local primary distribution voltage and any transformers required are furnished by the Customer, the monthly rate will be subject to a discount of: six (6) cents per month per kilowatt (kW) of the Customer's demand used in the calculation of the Local Facilities Charge for those customers which are billed under the 100 to 499 kW demand range; or six (6) cents per month per kilowatt (kW) of the Customer's demand used in the calculation of the Local Facilities Charge for those customers which are billed under the 500 to 7,499 kW demand range; and an additional discount of one percent (1%) of the Energy Charge and one percent (1%) of the Demand Charge.

TRANSFORMER OWNERSHIP DISCOUNT AND TRANSMISSION METERING VOLTAGE DISCOUNTS:

When the Company renders service under this Rate Schedule from an available transmission line of 46,000 volts or higher and the Customer furnishes, operates, and maintains the complete step-down transformer substation necessary to receive and use such service, the monthly rate will be subject to a discount of seven (7) cents per month per kilowatt (kW) of the Customer's demand used in the calculation of the Local Facilities Charge for those customers which are billed under the 500 to 7,499 kW demand range and an additional discount of two percent (2%) of the Energy Charge and two percent (2%) of the Demand Charge. The monthly rate will be subject to a discount of six (6) cents per kilowatt (kW) of the demand used in the calculation of the Local Facilities Charge for those customers which are billed under the above 7,499 kW demand range and an additional discount of one percent (1%) of the Energy Charge and one percent (1%) of the Demand Charge.

TERM OF CONTRACT:

Service under this rate schedule shall be for a minimum period of five (5) years and shall continue thereafter from year to year until terminated by either party upon twenty-four (24) months written notice to the other.

DEPOSIT:

A deposit amounting to twice the estimated average monthly bill may be required before service is connected at designated premises. The deposit may be applied to any final bills against the Customer for service.

ISSUED BY: S. W. Connally, Jr.

GULF POWER
A SOUTHERN COMPANY

Section No. VI
Sixth Revised Sheet No. 6.76
Canceling Fifth Revised Sheet No. 6.76

[redacted]

(Continued from Rate Schedule RSVP, Sheet No. 6.75)

If a Customer moves into a residence with existing Company-owned energy management equipment, the Customer will receive service under Rate Schedule RSVP. The Customer will be given the option of remaining on Rate Schedule RSVP or moving to Rate Schedule RS. If the Customer chooses Rate Schedule RS at that time, Company-owned energy management equipment will be removed free of charge.

CHARACTER OF SERVICE:

Available for single-phase service from local distribution lines of the Company's system at nominal secondary voltage of 120/240 volts. Service shall be metered through one metering device capable of measuring electrical energy consumption during the various times each energy demand charge is in effect.

RATES:

Base Charge:	$0.60 per day
Energy Demand Charge:	
Low Cost Hours (P_1):	4.884¢ per kWh
Medium Cost Hours (P_2):	4.884¢ per kWh
High Cost Hours (P_3):	4.884¢ per kWh
Critical Cost Hours (P_4):	4.884¢ per kWh

ISSUED BY: S. W. Connally, Jr.

GULF POWER
A SOUTHERN COMPANY

Section No. VI
Original Sheet No. 6.92

Part
1 of 2

EFFECTIVE DATE

Rate Rider LBIR
Experimental Rate Rider
Large Business Incentive Rider
(Optional Rider)

AVAILABILITY:

This Rate Rider is available to all Customers within Gulf Power's service area who meet qualifying load and employment requirements.

The qualifying load and employment requirements under this Rider must be achieved at the same delivery point. Additional metering equipment may be required for service under this Rider.

APPLICABILITY:

Applicable to New Load as a Rate Rider to the rates specified below. All terms and conditions of the rate under which the Customer takes service remain applicable, except that the Customer's billing will be credited by the incentive specified below beginning with the commencement of service pursuant to this Rider. New Load is that which is added via connection of initial service after the effective date of this Rider but not later than December 31, 2015. This Rider does not apply to provision of electric service through existing delivery points.

Rate Rider LBIR shall only be combined with Rate Schedules LP, LPT, PX, PXT or RTP. If a change in ownership occurs during the Term of Service under this Rider, the successor Customer may be allowed to fulfill the balance of the Contract under this Rider.

ISSUED BY: S. W. Connally, Jr.

GULF POWER
A SOUTHERN COMPANY

Section No. VI
Original Sheet No. 6.93

(Continued from Rate Rider LBIR, Sheet No. 6.92)

INCENTIVES:

Subject to compliance with the terms and conditions hereof, the following credits will be applied to the base demand charges and base energy charges of the Customer's applicable rate schedule:

- Year 1 – 60% reduction in base demand and base energy charges
- Year 2 – 45% reduction in base demand and base energy charges
- Year 3 – 30% reduction in base demand and base energy charges
- Year 4 – 15% reduction in base demand and base energy charges
- Year 5 – 0% reduction in base demand and base energy charges

Qualifying Loads:

(1) Qualifying load must be at least 1,000 kW, as determined by the Company.
(2) The Customer must provide audit documentation by the Florida Department of Economic Opportunity proving the hiring of 25 full-time employees per 1,000 kW of qualifying load.
(3) The Customer must demonstrate new capital investment of at least $1,000,000.
(4) The Customer must provide an affidavit verifying that the availability of the Rider is a significant factor in the Customer's decision to request service from Gulf Power Company.

TERM:

Service under this Rate Rider requires a Contract for Electric Service that includes a minimum five-year term. Service under this Rider will terminate at the end of the contract term.

During the term of service under this Rate Rider, the Customer may elect to change to an applicable rate to which Rate Rider LBIR does not apply so long as the Customer commits to take service under the newly selected rate for the unexpired duration of the term of the original Contract for Electric Service.The Company may terminate service under this Rider at any time if the Customer fails to comply with the terms and conditions of this Rider. Failure to: (1) maintain that level of employment specified in this Rider and/or (2) purchase from the Company the amount of load specified in this Rider may be considered grounds for termination.

Service under this Rider is subject to the Rules and Regulations of the Company and the Florida Public Service Commission.

ISSUED BY: S. W. Connally, Jr

GULF POWER
A SOUTHERN COMPANY

Section No. VI
Original Sheet No. 6.94

[redacted]

Rate Rider SBIR
Experimental Rate Rider
Small Business Incentive Rider
(Optional Rider)

AVAILABILITY:

This Rate Rider is available to all Customers within Gulf Power's service area who meet qualifying load and employment requirements.

The qualifying load and employment requirements under this Rider must be achieved at the same delivery point. Additional metering equipment may be required for service under this Rider.

APPLICABILITY:

Applicable to New Load as a Rate Rider to the rates specified below. All terms and conditions of the rate under which the Customer takes service remain applicable, except that the Customer's billing will be credited by the incentive specified below beginning with the commencement of service pursuant to this Rider. New Load is that which is added via connection of initial service after the effective date of this Rider but not later than December 31, 2015. This Rider does not apply to provision of electric service through existing delivery points.

Rate Rider SBIR shall only be combined with Rate Schedules GSD, GSDT, GSTOU, LP, LPT, PX, PXT or RTP. If a change in ownership occurs during the Term of Service under this Rider, the successor Customer may be allowed to fulfill the balance of the Contract under this Rider.

ISSUED BY: S. W. Connally, Jr.

GULF POWER
A SOUTHERN COMPANY

Section No. VI
Original Sheet No. 6.95

[redacted]

(Continued from Rate Rider SBIR, Sheet No. 6.94)

INCENTIVES:

Subject to compliance with the terms and conditions hereof, the following credits will be applied to the base demand charges and base energy charges of the Customer's applicable rate schedule:

- Year 1 – 20% reduction in base demand and base energy charges
- Year 2 – 15% reduction in base demand and base energy charges
- Year 3 – 10% reduction in base demand and base energy charges
- Year 4 – 5% reduction in base demand and base energy charges
- Year 5 – 0% reduction in base demand and base energy charges

Qualifying Loads:

(1) Qualifying load must be at least 200 kW, as determined by the Company.
(2) The Customer must provide audit documentation by the Florida Department of Economic Opportunity proving the hiring of 10 full-time employees.
(3) The Customer must provide an affidavit verifying that the availability of the Rider is a significant factor in the Customer's decision to request service from Gulf Power Company.

TERM:

Service under this Rate Rider requires a Contract for Electric Service that includes a minimum five-year term. Service under this Rider will terminate at the end of the contract term.

During the term of service under this Rate Rider, the Customer may elect to change to an applicable rate to which Rate Rider SBIR does not apply so long as the Customer commits to take service under the newly selected rate for the unexpired duration of the term of the original Contract for Electric Service. The Company may terminate service under this Rider at any time if the Customer fails to comply with the terms and conditions of this Rider. Failure to: (1) maintain that level of employment specified in this Rider and/or (2) purchase from the Company the amount of load specified in this Rider may be considered grounds for termination.

Service under this Rider is subject to the Rules and Regulations of the Company and the Florida Public Service Commission.

ISSUED BY: S. W. Connally, Jr.

Section VII
Second Revised Sheet No. 7.11
Canceling First Revised Sheet No. 7.11

Reserved for Future Use

Section VII
Second Revised Sheet No. 7.12
Canceling First Revised Sheet No. 7.12

Reserved for Future Use

Section VII
Seventh Revised Sheet No. 7.13
Canceling Sixth Revised Sheet No. 7.13

GULF POWER COMPANY
OUTDOOR SERVICE - LIGHTING PRICING METHODOLOGY
MONTHLY RATES - Rate Schedule OS (Part I/II)
Form 4

SECTION A - LED FIXTURES

Total Unit Cost	
Fixture Cost	$0.00
Arm Cost	$0.00
Bulb Cost	$0.00
Photocell Cost	$0.00
SUBTOTAL	$0.00
0.000 Man-hours to Install Fixture/Arm (If Applicable) @ $53.28/Manhour	$0.00
SUBTOTAL	$0.00
36.0% Engineering & Supervision Overheads	$0.00
UNIT COST TOTAL	$0.00
Fixture Charge	
Fixed Charge = (15.235% x Unit Cost Total)/12 Months	$0.00
Revenue Tax = Fixed Charge x 0.000721	$0.00
FIXTURE CHARGE	**$0.00**
Maintenance Charge	
Average Annual Bulb Failure Rate : 0.0%	
Bulb Life (in hours) Failure Rate = (Ann. Burn Hrs / Bulb Life)	
Annual Burn hours	
Photocell Replacement = (Photocell Cost + Labor) x Photocell Failure Rate/12 Months	$0.00
Photocell Life (in hours) Failure Rate = (Ann. Burn Hrs / Photocell Life)	
$ Photocell Cost = 0	
Photocell Replacement Labor Hrs	
Driver Replacement = (Driver Cost + Labor) x Driver Failure Rate/12 Months	$0.00
Driver Life (in hours) Failure Rate = (Ann. Burn Hrs / Driver Life)	
$ Driver Cost = 0	
Driver Replacement Labor Hrs	
Surge Protection Device (SPD) Replacement = (SPD Cost + Labor) x SPD Failure Rate/12 Months	$0.00
SPD Life (in hours) Failure Rate = (Ann. Burn Hrs / SPD Life)	
$ SPD Cost = 0	
SPD Replacement Labor Hrs	
Luminaire Repair Cost =	
[Man-hours to Remove of 0.36 @ $53.28/Manhour + Unit Cost Total]	
x 6.7% Annual Luminaire Failure Rate/12 Months	$0.00
SUBTOTAL	$0.00
Revenue Tax = Subtotal x 0.000721	$0.00
MAINTENANCE CHARGE	**$0.00**
Energy Charge	
0 Line Wattage x 4,120 Annual Operating Hours/(1,000 x 12) =	
0 kWh @ $0.02448/kWh **ENERGY CHARGE**	**$0.00**

PRICE SUMMARY	
Fixture Charge	**$0.00**
Maintenance Charge	**$0.00**
Energy Charge	**$0.00**
TOTAL MONTHLY CHARGE PER FIXTURE	**$0.00**

Section VII
Original Sheet No. 7.13.1

Form 4 (Continued)

SECTION A-1 - Non-LED FIXTURES

Total Unit Cost	
Fixture Cost	$0.00
Arm Cost	$0.00
Bulb Cost	$0.00
Photocell Cost	$0.00
SUBTOTAL	$0.00
0.000 Man-hours to Install Fixture/Arm (If Applicable) @ $53.28/Manhour	$0.00
SUBTOTAL	$0.00
36.0% Engineering & Supervision Overheads	$0.00
UNIT COST TOTAL	$0.00
Fixture Charge	
Fixed Charge = (15.235% x Unit Cost Total)/12 Months	$0.00
Revenue Tax = Fixed Charge x 0.000721	$0.00
FIXTURE CHARGE	**$0.00**
Maintenance Charge	
Average Annual Bulb Failure Rate : 0.0%	
Bulb Life (in hours) Failure Rate = (Ann. Burn Hrs / Bulb Life)	
Annual Burn hours	
Spot Rebulb Cost = (Bulb Cost + Photocell Cost + $29 Labor) x Bulb Failure Rate/12 Months	$0.00
Luminaire Repair Cost = [Man-hours to Remove of 0.36 @ $53.28/Manhour + Unit Cost Total] x 6.7% Annual Luminaire Failure Rate/12 Months	$0.00
SUBTOTAL	$0.00
Revenue Tax = Subtotal x 0.000721	$0.00
MAINTENANCE CHARGE	**$0.00**
Energy Charge	
Line Wattage x 4,120 Annual Operating Hours/(1,000 x 12) = 0 kWh @ $0.02448/kWh **ENERGY CHARGE**	**$0.00**

PRICE SUMMARY	
Fixture Charge	**$0.00**
Maintenance Charge	**$0.00**
Energy Charge	**$0.00**
TOTAL MONTHLY CHARGE PER FIXTURE	**$0.00**

ISSUED BY: S. W. Connally, Jr. EFFECTIVE:

Section VII
Sixth Revised Sheet No. 7.14
Canceling Fifth Revised Sheet No. 7.14

Form 4 (Continued)

SECTION B - POLES AND ADDITIONAL FACILITIES

Total Unit Cost	
Material Cost of Pole or Additional Facility	$0.00
0.000 Man-hours to Install Pole/Additional Facility @ $53.28/Manhour	$0.00
SUBTOTAL	$0.00
36.0% Engineering & Supervision Overheads	$0.00
UNIT COST TOTAL	$0.00
Pole/Additional Facility Charge	
Fixed Charge = (15.235% x Unit Cost Total)/12 Months	$0.00
Revenue Tax = Fixed Charge x 0.000721	$0.00
MONTHLY POLE/ADDITIONAL FACILITY CHARGE PER UNIT	**$0.00**

ISSUED BY: S. W. Connally, Jr.

EFFECTIVE:

Section VII
Seventh Revised Sheet No. 7.15
Canceling Sixth Revised Sheet No. 7.15

Form 4 (Continued)

SECTION C - RELAMPING SERVICE AGREEMENT

Bulb and Photocell Cost	
Bulb Cost	$0.00
Photocell Cost	$0.00
BULB AND PHOTOCELL COST	$0.00
Relamping Charge	
Average Annual Bulb Failure Rate : 0.0%	
Bulb Life (in hours) Failure Rate = (Ann. Burn Hrs / Bulb Life)	
Annual Burn hours	
Spot Rebulb Cost =(Bulb Cost + Photocell Cost + $29 Labor) x Bulb Failure Rate/12 Months	$0.00
SUBTOTAL	$0.00
Revenue Tax = Subtotal x 0.000721	$0.00
RELAMPING CHARGE	**$0.00**
Energy Charge	
0 Line Wattage x 4,120 Annual Operating Hours/(1,000 x 12) =	
0 kWh @ $0.02448/kWh **ENERGY CHARGE**	**$0.00**

PRICE SUMMARY	
Relamping Charge	**$0.00**
Energy Charge	**$0.00**
TOTAL MONTHLY CHARGE PER FIXTURE	**$0.00**

ISSUED BY: S. W. Connally, Jr. EFFECTIVE:

Eighteenth Revised Sheet No. 7.16
Canceling Seventeenth Revised Sheet No. 7.16

GULF POWER COMPANY
CONTRACT FOR STREET AND
GENERAL AREA LIGHTING SERVICE
RATE SCHEDULE OS (PART I/II)

Form 5

Contract No. _____

Customer Name _____ Date _____

DBA _____ Telephone No. _____ Tax I. D. (if applicable) _____

Street Address (Subdivision, etc.) of Light(s) _____

Billing Address _____

Driving Directions _____

_____

Location of Light(s) _____

Meter No. _____ Account No. _____ JETS WO No. _____

The Applicant requests Gulf Power Company to furnish the facilities described on Sheet No. 7.16.1 and the necessary electric energy for the operation thereof and hereby agrees to take and pay for the same in accordance with and subject to the Company's Rate Schedule "OS (PART I/II)" and Rules and Regulations for Electric Service on file in its office and on file with the Florida Public Service Commission or any changes therein as approved by the Florida Public Service Commission. In consideration of the supplying and maintenance of said electric current and facilities the Applicant hereby grants to Gulf Power Company, the right to construct, operate, and maintain upon, over, under, and across the premises located at the above service address its poles, lines, facilities, and appliances necessary in connection therewith for the transmission of electric power together with the rights of ingress and egress to and from said lines and the right to cut and keep clear all trees and other obstructions that may injure or endanger said lines. All fixtures, equipment and material used in the construction, operation, and maintenance of said facilities shall remain at all times the property of Gulf Power Company. The contract term as provided by Rate Schedule "OS (PART I/II)" shall be for an initial period of not less than three (3) years. Additional facilities required for the installation may constitute a longer term. At the time Gulf Power Company begins to install any facilities applied for herein, this application becomes a contract for a term of _____ years and thereafter from year to year until terminated by notice to either party by the other. Any damage done by vandalism shall be handled in accordance with the provisions of Rate Schedule "OS (Part I/II)". The location of said facilities shall be as specified by the Applicant and the Company shall be held harmless in connection therewith or the use thereof. Should the Applicant discontinue this service before the expiration of the full term of contract all unpaid charges for the full term shall immediately become due and payable. In the event the supply of electric current should be interrupted or fail by reason of accident, or condition beyond the control of Gulf Power Company, the service shall be restored within a reasonable time and such interruption shall not constitute a breach of the contract, nor shall Gulf Power Company be liable for damages by reason of such interruption or failure. For street lights, lamps are located on MAP which is hereto appended and made a part hereof.

GULF POWER COMPANY	CUSTOMER
Application Taken By _____	Customer _____
Approved by _____ Authorized Company Representative	Title _____
Signature _____	Signature _____
Date _____	Date _____

ISSUED BY: S. W. Connally, Jr. EFFECTIVE:

Section No. VII
Sixth Revised Sheet No. 7.24
Canceling Fifth Revised Sheet No. 7.24

GULF POWER COMPANY

AGREEMENT FOR UNDERGROUND ELECTRIC CONSTRUCTION BY THE UTILITY
Form 8

THIS AGREEMENT made and entered into this _____ day of _____, 20____, by and between GULF POWER COMPANY, hereinafter called the Utility, and _____, hereinafter called the Applicant, sets forth the standards and conditions which will apply to the construction, installation, repair and ownership of the underground facilities to be located at _____, Exhibit "A" hereto, contains a detailed description of the property where the facilities will be constructed or installed.

WITNESSETH THAT:

WHEREAS, the Utility owns and operates an electric distribution system in _____ County, Florida, in which the Applicant owns the real property described in Exhibit "A" on some or all of which the Applicant has constructed or proposes to construct certain improvements; and

WHEREAS, the Applicant has requested the Utility to supply and install all primary, secondary, and service trench, duct, and cable for the purpose of supplying electric service to the improvements to be located on the property described on Exhibit "A"; and

WHEREAS, the Utility desires to cooperate with the Applicant and to install the underground distribution system;

NOW, THEREFORE, in consideration of the premises and of the mutual agreements hereinafter set forth, it is agreed by and between the parties as follows:

1. Upon compliance by Applicant with all of the provisions of this Agreement in a manner acceptable to the Utility, the Utility shall install, own and maintain the necessary facilities for providing underground electric service to the improvements located on that portion of the property as shown on Exhibit "C" (construction drawing) attached. At no time shall the Utility be required by the Applicant, its successors or assigns to furnish other than single phase service through these facilities except as otherwise shown on Exhibit "C" and at a cost to the Applicant as specifically described in Exhibit "C".

2. The Applicant agrees to prepare an orderly plan for the location of all utility lines and equipment to be installed and to cause all utility companies and contractors involved to install their lines and equipment in the locations specified in said plan.

3. The Applicant agrees to cause to be conveyed to the Utility, without cost, all easements, including rights of ingress and egress, necessary or convenient to the Utility or required by it for the purpose of constructing, operating, maintaining, and removing said underground electrical distribution lines and other necessary equipment.

4. The Applicant shall remove or cause to be removed, at his expense, from the Utility easement or route of trench line, whether in a street, alley or otherwise, all trees, stumps or any other obstructions and shall not hard surface street, parking areas, courts, walkways, or other areas on the trench line route until the necessary ducts have been installed by the Utility. The Applicant shall locate and mark all property and/or lot corners and establish finish grade along the route of construction of the underground distribution system. The Applicant agrees to reimburse the Utility for the costs of facilities found to be installed at the wrong location or grade due to Applicant requested changes in property lines, easement, grade, and/or errors in staking or trenching.

5. The service entrance facilities for the improvements shall in all respects conform to the requirements of all applicable codes, the Rules and Regulations of the Utility, and the terms of this Agreement. The Applicant and his successors in interest will provide the service entrance facilities in accordance with Exhibit "B" (appropriate distribution standard specification).

NOW, THEREFORE, in consideration of the premises and of the mutual agreements hereinafter set forth, it is agreed by and between the parties as follows:

1. The Utility hereby agrees to permit the Applicant to construct and install all or a portion of the underground distribution facilities described herein below at the above location provided:

a) such work meets the Utility's construction standards, as set forth below:

(1) Conduit to be placed in any Utility underground distribution system must meet the specifications set forth in Exhibit "D" (appropriate distribution standard specification). Conduit shall be installed in the locations specified in Exhibit "C" (construction drawing);

(2) Primary and secondary conduit must be buried with 30" of cover or at a depth that meets applicable codes and is satisfactory to the utility and the applicant;

(3) The connection between the meter enclosure and the underground service entrance shall be in accordance with Exhibit "B" (appropriate distribution standard specification);

(4) Where the applicant installs the conduit, the applicant must install a tracer wire in the trench with the conduit as specified in Exhibit "E";

(5) When the Utility supplies the conduit to the Applicant, the Utility shall take ownership of that conduit at the time it is installed by the Applicant and all other provisions of this agreement have been satisfied. When the Applicant supplies and installs the conduit, the Utility shall take ownership of that conduit at the time the cable has been installed in the conduit by the Utility and all other provisions of this agreement have been satisfied. Until such time that the Utility takes ownership of the conduit, the Applicant, or Contractor acting for the Applicant, shall be responsible for accessing and repairing the conduit;

(6) After which time the Utility takes ownership of the conduit, the Utility shall be responsible for accessing, in a reasonable manner, and repairing the conduit and cable. The Applicant's

aforementioned duty includes, but is not limited to, repairs necessitated by the Utility accessing and repairing conduit or cable and specifically includes all repairs made necessary as a result of placement of conduit beneath a roadway. The Applicant will have no right, title or interest in or to the completed distribution facilities;

(7) The Utility reserves the right to verify, prior to taking ownership of the conduit system, that the duct system is installed as specified in the plan provided by the Utility under section 4, below. The Utility may exercise, at any time, its right to inspect and verify any Applicant provided facility, and any such inspection or verification shall not be deemed an approval of any Applicant provided facility or a waiver by the Utility of any right to enforce strict compliance with the terms and conditions of this agreement;

(b) that in the Utility's sole discretion such Agreement is not expected to cause the general body of ratepayers to incur greater costs;

(c) the Applicant agrees to pay Gulf Power Company's current applicable Engineering and Supervision rate associated with the estimate of work to be performed by the Applicant. This amount represents the cost of Gulf's engineering time to review and inspect the Applicant's work.

(d) the Applicant agrees to correct, to the satisfaction of the Utility, any deficiencies found by the Utility prior to the connection of any customers to the underground electric distribution system or the connection of the underground electric distribution facilities to Utility's distribution system. Deficiencies must be corrected in a timely manner or the Utility shall construct the system improvement using overhead facilities and the Applicant will have to pay the cost of such improvement and the cost of its removal before the corrected underground facilities will be connected;

2. Upon compliance by Applicant with all of the provisions of this Agreement in a manner acceptable to the Utility, the Utility shall own and maintain the necessary facilities for providing underground electric service to the property as shown on Exhibit "C" hereto. At no time shall the Utility be required by the Applicant, its successors or assigns to furnish other than single phase service through these facilities, except as otherwise shown on Exhibit "C". Three-phase service will be furnished only when specified on Exhibit "C" and paid for in advance by the Applicant. The Applicant agrees to reimburse the Utility for the costs of facilities found to be installed at the wrong location or grade due to Applicant requested changes in property lines, easement, grade, and/or errors in staking or trenching.

Section VII
First Revised Sheet No. 7.43
Canceling Original Sheet No. 7.43

APPLICATION FOR UNDERGROUND COST ESTIMATE
(Form 17)

Name _____

Address _____

Phone _____

Type estimate requested _____ Non-binding _____ Binding

Location / description of requested project _____

_____

_____

_____

_____

_____

_____

This application and the deposit paid is for the purpose of obtaining a estimate of the cost of underground facilities pursuant to Section IV Part VI of Gulf Power Company's Tariff for Retail Service, Sheets 4.21 through 4.28.1. Said provisions govern this application as if fully set forth herein.

Signed _____

Amount paid $ _____
(Binding cost estimate only)
(To be calculated by Gulf Power in accordance with Tariff Section IV, Subpart 6.5.3)

FOR COMPANY USE ONLY

Length in miles of underground trench or overhead primary to be converted _____

Amount of deposit $_____

Received by _____

Date Received by Gulf Power Company _____

Notice: The deposit paid applies specifically to the scope of work defined above. It cannot be credited to charges for any other work due to revisions in the scope.

ISSUED BY: S. W. Connally, Jr. **EFFECTIVE:**

GULF POWER COMPANY
OPTIONAL RELAMPING SERVICE AGREEMENT
CUSTOMER-OWNED STREET AND GENERAL AREA LIGHTING
RATE SCHEDULE OS (PART I/II)
Form 19

Contract No. _____

Customer Name _____ Date _____

DBA _____ Telephone No. _____ Tax I. D.. _____

Street Address (Subdivision, etc.) of Light(s) _____

Mailing Address _____

Driving Directions _____

_____

Location of Light(s) _____
Meter No. _____ Account No. _____ JETS WO No.

UNMETERED CUSTOMER-OWNED FIXTURES:
High Pressure Sodium Vapor Lighting:

_____ 8,800 Lumen (100 Watts) Light(s) to be billed at a base rate of $1.68 each per month	$ _____
_____ 16,000 Lumen (150 Watts) Light(s) to be billed at a base rate of $2.33 each per month	$ _____
_____ 20,000 Lumen (200 Watts) Light(s) to be billed at a base rate of $2.65 each per month	$ _____
_____ 25,000 Lumen (250 Watts) Light(s) to be billed at a base rate of $3.15 each per month	$ _____
_____ 46,000 Lumen (400 Watts) Light(s) to be billed at a base rate of $4.70 each per month	$ _____
_____ 125,000 Lumen (1000 Watts) Light(s) to be billed at a base rate of $10.16 each per month	$ _____

Metal Halide Lighting:

_____ 32,000 Lumen (400 Watts) Light(s) to be billed at a base rate of $4.81 each per month	$ _____

METERED CUSTOMER-OWNED FIXTURES:
High Pressure Sodium Vapor Lighting:

_____ 8,800 Lumen (100 Watts) Light(s) to be billed at a base rate or $0.68 each per month	$ _____
_____ 16,000 Lumen (150 Watts) Light(s) to be billed at a base rate of $0.67 each per month	$ _____
_____ 20,000 Lumen (200 Watts) Light(s) to be billed at a base rate of $0.69 each per month	$ _____
_____ 25,000 Lumen (250 Watts) Light(s) to be billed at a base rate or $0.70 each per month	$ _____
_____ 46,000 Lumen (400 Watts) Light(s) to be billed at a base rate or $0.69 each per month	$ _____
_____ 125,000 Lumen (1000 Watts) Light(s) to be billed at a base rate of $0.88 each per month	$ _____

Metal Halide Lighting:

_____ 32,000 Lumen (400 Watts) Light(s) to be billed at a base rate or $0.82 each per month	$ _____
Total Base Monthly Charge*	$ _____

*Base monthly charge does not include Fuel Charge, Purchased Power Capacity Charge, Environmental Charge, Energy Conservation Charge, Natural Disaster Recovery Surcharge, applicable taxes, or fees.

The Applicant requests a relamping service agreement on the lamp(s) and photocell(s) for the fixtures described above and the necessary electric energy (if unmetered) for the operation thereof and hereby agrees to take and pay for the same in accordance with and subject to the Company's Rate Schedule "OS (PART I/II)" and Rules and Regulations for Electric Service on file in its office and on file with the Florida Public Service Commission or any changes therein as approved by the Florida Public Service Commission. This agreement and the monthly rates set forth above cover both the electric service (if unmetered) and the replacement of lamps and photoelectric controls upon routine failure. Lamps or photoelectric controls damaged or destroyed due to vandalism or willful abuse are not covered by this agreement and will only be replaced at the Applicant's expense. The Applicant remains responsible for all maintenance other than the replacement of lamps and photoelectric controls. The distribution system shall serve no other electrical loads except the lighting equipment described above.

Section VII
Seventh Revised Sheet No. 7.55
Canceling Sixth Revised Sheet No. 7.55

GULF POWER COMPANY
CUSTOMER-OWNED LIGHTING AGREEMENT
(WITHOUT RELAMPING SERVICE PROVISIONS)
RATE SCHEDULE OS (PART I/II)

Form 24

Contract No. _____

Customer Name _____ Date _____

DBA _____ Telephone No. _____ Tax I. D. _____

Street Address (Subdivision, etc.) of Light(s) _____

Billing Address _____

Driving Directions _____

No. of Light(s) _____ Location of Light(s) _____

Meter No. _____ Account No. _____

JETS WO No. _____ **CUSTOMER-OWNED FIXTURE(S):**

High Pressure Sodium

_____ 8800 Lumen (100 Watts) Light(s) to be billed at a base rate of $1.00 each per month $_____
_____ 25000 Lumen (250 Watts) Light(s) to be billed at a base rate of $2.45 each per month $_____
_____ 46000 Lumen (400 Watts) Light(s) to be billed at a base rate of $4.01 each per month $_____
_____ 125000 Lumen (1000 Watts) Light(s) to be billed at a base rate of $9.28 each per month $_____

Metal Halide

_____ 12000 Lumen (175 Watts) Light(s) to be billed at a base rate of $1.76 each per month $_____
_____ 13000 Lumen (150 Watts PS) Light(s) to be billed at a base rate of $1.59 each per month $_____
_____ 32000 Lumen (400 Watts) Light(s) to be billed at a base rate of $3.99 each per month $_____
_____ 100000 Lumen (1000 Watts) Light(s) to be billed at a base rate of $9.25 each per month $_____

All others to be billed as follows:

_____ Light(s) @ a base rate of $_____ * each per month (kWh for one light = _____) $_____
_____ Light(s) @ a base rate of $_____ * each per month (kWh for one light = _____) $_____
_____ Light(s) @ a base rate of $_____ * each per month kWh for one light = _____) $_____
Total Base Monthly Charge** $_____

* This base rate per light is calculated by taking the kWh for one light and multiplying by $0.02448/kWh. Repeat this line for each different type of customer-owned light other than the 8800 Lumen, 12000 Lumen, 13000 Lumen, 25000 Lumen, 32000 Lumen, 46000 Lumen, 100000 Lumen, or 125000 Lumen lights shown above.

** Base monthly charge does not include Fuel Charge, Purchased Power Capacity Charge, Environmental Charge, Energy Conservation Charge, Natural Disaster Recovery Surcharge, applicable taxes, or fees.

The Applicant requests the necessary electric energy for the operation thereof for the fixtures described above and hereby agrees to take and pay for the same in accordance with and subject to the Company's Rate Schedule "OS (PART I/II)" and Rules and Regulations for Electric Service on file in its office and on file with the Florida Public Service Commission or any changes therein as approved by the Florida Public Service Commission. This agreement and the monthly rates set forth above cover the electric service. The distribution system shall serve no other electrical loads except the lighting equipment described above.

GULF POWER
A SOUTHERN COMPANY

Section No. VIII
Third Revised Sheet No. 8.0
Canceling Second Revised Sheet No. 8.0

[redacted]	[redacted]

Gulf does not presently have in place any special contracts for the sale of electricity.

ISSUED BY: S. W. Connally, Jr.

Proposed Tariff Sheets

Proposed Tariff Sheets consisting of 32 pages, including this cover sheet.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130140-EI EXHIBIT 27
PARTY Gulf Power Company (Gulf) Direct
DESCRIPTION James I. Thompson (JIT-2)
DATE

GULF POWER
A SOUTHERN COMPANY

Section No. VI
Thirty-First Revised Sheet No. 6.3
Canceling Thirtieth Revised Sheet No. 6.3

RATE SCHEDULE RS
RESIDENTIAL SERVICE
URSC: RS

[redacted]

AVAILABILITY:

Available throughout the entire territory served by the Company.

APPLICABILITY:

Applicable for service used for domestic purposes at an individually metered dwelling unit suitable for year-round family occupancy containing full kitchen facilities and to commonly-owned facilities in condominium and cooperative apartment buildings. Garages, pools, pumps, boat dock, etc., on the same premise as the dwelling unit are included if all such service is for personal use. Service provided hereunder shall not be shared with or resold to others.

CHARACTER OF SERVICE:

Available for single phase service from local distribution lines of the Company's system at nominal secondary voltage of 120/240 volts.

RATES:

Base Charge: $0.62 per day

Energy-Demand Charge: 5.018¢ per kWh

MINIMUM BILL:

In consideration of the readiness of the Company to furnish such service, a monthly minimum charge will be made of not less than the Base Charge.

DEPOSIT:

A deposit amounting to twice the estimated average monthly bill may be required before service is connected at designated premises. The deposit may be applied to any final bills against the Customer for service.

ISSUED BY: S.W. Connally, Jr.

GULF POWER
A SOUTHERN COMPANY

Section No. VI
Twenty-Fifth Revised Sheet No. 6.5
Canceling Twenty-Fourth Revised Sheet No. 6.5

RATE SCHEDULE GS
GENERAL SERVICE – NON-DEMAND
URSC: GS

[redacted]

AVAILABILITY:

Available throughout the entire territory served by the Company.

APPLICABILITY:

Applicable for general lighting and power service covering the entire electrical requirements of any Customer with a demand of less than 25 kW except for service to which another Rate Schedule is applicable. Service to two or more premises shall not be combined nor shall service furnished hereunder be shared with or resold to others. All service shall be taken at the same voltage and from a single delivery point.

CHARACTER OF SERVICE:

The delivery voltage to the Customer shall be the voltage of the available distribution lines of the Company for the locality in which service is to be rendered. Three phase service may be furnished at the request of the Customer subject to the Rules and Regulations of the Company which govern the extension of three phase service.

MONTHLY RATES:

Base Charge: $21.48

Energy-Demand Charge: 5.422¢ per kWh

MINIMUM MONTHLY BILLS:

In consideration of the readiness of the Company to furnish such service, no monthly bill will be rendered for less than the Base Charge.

ISSUED BY: S. W. Connally, Jr.

GULF POWER
A SOUTHERN COMPANY

Section No. VI
Twenty-Fourth Revised Sheet No. 6.7
Canceling Twenty-Third Revised Sheet No. 6.7

RATE SCHEDULE GSD
GENERAL SERVICE - DEMAND
URSC: GSD

[redacted]

AVAILABILITY:

Available throughout the entire territory served by the Company.

APPLICABILITY:

Applicable for commercial, industrial, or institutional general service on an annual basis covering the entire electrical requirements of any Customer whose highest actual measured demand is not more than four hundred ninety-nine (499) kilowatts. Service to two or more premises shall not be combined nor shall service furnished hereunder be shared with or resold to others. All service shall be taken at the same voltage, from a single delivery point, and shall be measured by a single meter.

CHARACTER OF SERVICE:

The delivery voltage to the Customer shall be the voltage of the available secondary distribution lines of the Company for the locality in which service is to be rendered. Three phase service may be furnished at the request of the Customer subject to the Rules and Regulations of the Company which govern the extension of the three phase service.

MONTHLY RATES:

Base Charge:	$45.10
Demand Charge:	$7.01 per kW of billing demand
Energy Charge:	1.793¢ per kWh

MINIMUM MONTHLY BILLS:

In consideration of the readiness of the Company to furnish such service, no monthly bill will be rendered for less than the Base Charge plus the Demand Charge.

ISSUED BY: S. W. Connally, Jr.

GULF POWER
A SOUTHERN COMPANY

Section No. VI
Twenty-Second Revised Sheet No. 6.8
Canceling Twenty-First Revised Sheet No. 6.8

(Continued from Rate Schedule GSD, Sheet No. 6.7)

DETERMINATION OF BILLING DEMAND:

The kilowatt (kW) billing demand for billing purposes shall be the Customer's maximum integrated fifteen (15) minute demand to the nearest kilowatt (kW) during each service month.

REACTIVE DEMAND CHARGE:

When the capacity required to be maintained is one-hundred (100) kilowatts or more, at the option of the Company, the monthly bill calculated at the above rates may be increased in the amount of $1.00 per kvar for all over 0.48432 kilovars per kilowatt (90% power factor). The kilovars to which this adjustment shall apply shall be the monthly maximum measured kilovar demand or may be calculated as the square root of the difference between the square of the maximum monthly measured kVA demand and the square of the maximum monthly measured kW demand.

TRANSFORMER OWNERSHIP DISCOUNT AND PRIMARY METERING VOLTAGE DISCOUNTS:

When the Company renders service under this Rate Schedule at the local primary distribution voltage and any transformers required are furnished by the Customer, the Monthly Rate will be subject to a discount of forty (40) cents per kW of the Customer's billing demand as determined above, and an additional discount of one percent (1%) of the Energy Charge and one percent (1%) of the Demand Charge; however, such deduction shall not reduce the minimum monthly bill specified above.

TERM OF CONTRACT:

Service under this Schedule shall be for a period of not less than one year and thereafter from year to year until terminated by three (3) months' written notice by either party to the other.

DEPOSIT:

A deposit amounting to twice the estimated average monthly bill may be required before service is connected at designated premises. The deposit may be applied to any final bills against the Customer for service.

ISSUED BY: S. W. Connally, Jr.

GULF POWER
A SOUTHERN COMPANY

Section No. VI
Twenty-Seventh Revised Sheet No. 6.10
Canceling Twenty-Sixth Revised Sheet No. 6.10

RATE SCHEDULE LP
LARGE POWER SERVICE
URSC: GSLD

[redacted]

AVAILABILITY:

Available throughout the entire territory served by the transmission system of the Company.

APPLICABILITY:

Applicable for three phase general service on an annual basis covering the entire electrical requirements of any Customer. Service to two or more premises shall not be combined nor shall service furnished hereunder be shared with or resold to others. All service shall be taken at the same voltage, from a single delivery point, and shall be measured by a single meter.

CHARACTER OF SERVICE:

The delivery voltage to the Customer shall be the voltage of the available secondary distribution lines of the Company for the locality in which service is to be rendered.

MONTHLY RATES:

Base Charge:	$260.00
Demand Charge:	$12.70 per kW of billing demand
Energy Charge:	0.970¢ per kWh

MINIMUM MONTHLY BILLS:

In consideration of the readiness of the Company to furnish such service, no monthly bill will be rendered for less than the Base Charge plus the Demand Charge.

ISSUED BY: S. W. Connally, Jr.

GULF POWER
A SOUTHERN COMPANY

Section No. VI
Twenty-Sixth Revised Sheet No. 6.11
Canceling Twenty-Fifth Revised Sheet No. 6.11

[redacted]

(Continued from Rate Schedule LP, Sheet No. 6.10)

DETERMINATION OF BILLING DEMAND:

The kilowatt (kW) billing demand for billing purposes shall be the Customer's maximum integrated fifteen (15) minute demand to the nearest kilowatt (kW) during each service month.

REACTIVE DEMAND CHARGE:

The monthly bill calculated at the above rates shall also be increased in the amount of $1.00 per kvar for all over 0.48432 kilovars per kilowatt (90% power factor). The kilovars to which this adjustment shall apply shall be the monthly maximum measured kilovar demand or may be calculated as the square root of the difference between the square of the maximum monthly measured kVA demand and the square of the maximum monthly measured kW demand.

TRANSFORMER OWNERSHIP DISCOUNT AND PRIMARY METERING VOLTAGE DISCOUNTS:

When the Company renders service under this Rate Schedule at the local primary distribution voltage and any transformers required are furnished by the Customer, the Monthly Rate will be subject to a discount of fifty-seven (57) cents per month per kilowatt (kW) of the Customer's billing demand as determined above, and an additional discount of one percent (1%) of the Energy Charge and one percent (1%) of the Demand Charge; however, such deduction shall not reduce the minimum monthly bill specified above.

TRANSFORMER OWNERSHIP DISCOUNT AND TRANSMISSION METERING VOLTAGE DISCOUNTS:

When the Company renders service under this Rate Schedule from an available transmission line of 46,000 volts or higher and the Customer furnishes, operates and maintains the complete step-down transformer substation necessary to receive and use such service the Monthly Rate will be subject to a discount of eighty-one (81) cents per month per kilowatt (kW) of the Customer's billing demand as determined above, and an additional discount of two percent (2%) of the Energy Charge and two percent (2%) of the Demand Charge; however, such deduction shall not reduce the minimum monthly bill specified above.

DEPOSIT:

A deposit amounting to twice the estimated average monthly bill may be required before service is connected at designated premises. The deposit may be applied to any final bills against the Customer for service.

ISSUED BY: S. W. Connally, Jr.

GULF POWER
A SOUTHERN COMPANY

Section No. VI
Twenty-Third Revised Sheet No. 6.13
Canceling Twenty-Second Revised Sheet No. 6.13

RATE SCHEDULE PX
LARGE HIGH LOAD FACTOR POWER SERVICE
URSC: GSLD1

[redacted]

AVAILABILITY:

Available throughout the entire territory served by the transmission system of the Company.

APPLICABILITY:

Applicable for three phase lighting and power service to any Customer whose actual measured demand is not less than 7,500 kilowatts (kW), with an annual load factor of not less than seventy-five percent (75%). Service to two or more premises shall not be combined nor shall service furnished hereunder be shared with or resold to others. All service shall be taken at the same voltage and from a single delivery point, and shall be measured by a single meter.

CHARACTER OF SERVICE:

The delivery voltage to the Customer shall be the standard secondary voltage of the Company's transformers supplied from the transmission lines of the Company.

MONTHLY RATES:

Base Charge:	$764.55
Demand Charge:	$11.16 per kW of billing demand
Energy Charge:	0.410¢ per kWh

MINIMUM MONTHLY BILL:

In the event the Customer's annual load factor for the current and preceding eleven months is less than 75% and in consideration of the readiness of the Company to furnish such service, the minimum monthly bill shall not be less than the Base Charge plus $13.40 per kW of billing demand.

ISSUED BY: S.W. Connally, Jr.

GULF POWER
A SOUTHERN COMPANY

Section No. VI
Twenty-Third Revised Sheet No. 6.16
Canceling Twenty-Second Revised Sheet No. 6.16

RATE SCHEDULE OS
OUTDOOR SERVICE
URSC: SL, OL, OL1, OL2

[redacted]

AVAILABILITY:

Available throughout the entire territory served by the Company.

OS-I/II STREET, ROADWAY, AND GENERAL AREA LIGHTING

APPLICABILITY:

Applicable for street, roadway, and general area lighting service under the provisions of the Company's standard contract for such service. Service hereunder includes power supply and may include lamp renewals and regular maintenance.

LIMITATION OF SERVICE:

Company-owned fixtures will be mounted on Company-owned poles of the Company's distribution system. Customer-owned fixtures will be mounted on Customer-owned poles, of a standard type and design, permitting service and maintenance at no abnormal cost to the Company.

MONTHLY RATES:
High Pressure Sodium Vapor

Initial Lamp Rating (Lumen)	Desc.	Lamp Wattage	Line Wattage	Est. kWh **	Fixture Charge	Maint. Charge	Energy Charge ***	Total Charge
5400*	Open Bottom	70	84	29	$3.12	$1.68	$0.72	$5.52
8800	Open Bottom	100	120	41	$2.66	$1.52	$1.01	$5.19
8800	Open Bottom w/Shield	100	120	41	$3.66	$1.79	$1.01	$6.46
8800	Acorn	100	120	41	$13.30	$4.48	$1.01	$18.79
8800	Colonial	100	120	41	$3.58	$1.76	$1.01	$6.35
8800	English Coach	100	120	41	$14.51	$4.82	$1.01	$20.34
8800	Destin Single	100	120	41	$24.96	$7.74	$1.01	$33.71
17600	Destin Double	200	240	82	$49.78	$14.94	$2.03	$66.75
5400*	Cobrahead	70	84	29	$4.37	$2.02	$0.72	$7.11
8800	Cobrahead	100	120	41	$3.66	$1.79	$1.01	$6.46
20000*	Cobrahead	200	233	80	$5.04	$2.20	$1.98	$9.22
25000	Cobrahead	250	292	100	$4.90	$2.17	$2.47	$9.54
46000	Cobrahead	400	477	164	$5.16	$2.23	$4.05	$11.44
8800	Cutoff Cobrahead	100	120	41	$4.05	$1.89	$1.01	$6.95
25000	Cutoff Cobrahead	250	292	100	$4.96	$2.19	$2.47	$9.62
46000	Cutoff Cobrahead	400	477	164	$5.18	$2.23	$4.05	$11.46
25000	Bracket Mount CIS	250	292	100	$11.36	$3.97	$2.47	$17.80
25000	Tenon Top CIS	250	292	100	$11.36	$3.97	$2.47	$17.80

ISSUED BY: S. W. Connally, Jr.

GULF POWER
A SOUTHERN COMPANY

Section No. VI
Thirty-Sixth Revised Sheet No. 6.16.1
Canceling Thirty-Fifth Revised Sheet No. 6.16.1

(Continued from Rate Schedule OS, Sheet No. 6.16)

High Pressure Sodium Vapor (continued)

Initial Lamp Rating (Lumen)	Desc.	Lamp Wattage	Line Wattage	Est. kWh **	Fixture Charge	Maint. Charge	Energy Charge ***	Total Charge
46000	Bracket Mount CIS	400	468	161	$12.08	$4.16	$3.98	$20.22
20000*	Small ORL	200	233	80	$11.63	$4.03	$1.98	$17.64
25000	Small ORL	250	292	100	$11.20	$3.92	$2.47	$17.59
46000	Small ORL	400	477	164	$11.73	$4.06	$4.05	$19.84
20000*	Large ORL	200	233	80	$18.95	$6.06	$1.98	$26.99
46000*	Large ORL	400	477	164	$21.35	$6.74	$4.05	$32.14
46000	Shoebox	400	477	164	$9.78	$3.52	$4.05	$17.35
16000	Directional	150	197	68	$5.49	$2.29	$1.68	$9.46
20000*	Directional	200	233	80	$7.94	$3.02	$1.98	$12.94
46000	Directional	400	477	164	$5.90	$2.44	$4.05	$12.39
125000	Large Flood	1000	1105	379	$9.37	$3.59	$9.37	$22.33

Metal Halide

Initial Lamp Rating (Lumen)	Desc.	Lamp Wattage	Line Wattage	Est. kWh **	Fixture Charge	Maint. Charge	Energy Charge ***	Total Charge
12000	Acorn	175	210	72	$13.43	$5.65	$1.78	$20.86
12000	Colonial	175	210	72	$3.71	$2.95	$1.78	$8.44
12000	English Coach	175	210	72	$14.64	$5.99	$1.78	$22.41
12000	Destin Single	175	210	72	$25.09	$8.91	$1.78	$35.78
24000	Destin Double	350	420	144	$50.04	$16.67	$3.57	$70.28
32000	Small Flood	400	476	163	$6.03	$2.61	$4.03	$12.67
32000	Small Parking Lot	400	476	163	$11.14	$4.05	$4.03	$19.22
100000	Large Flood	1000	1100	378	$8.65	$5.18	$9.34	$23.17
100000	Large Parking Lot	1000	1100	378	$19.24	$7.17	$9.34	$35.75

Metal Halide Pulse Start

Initial Lamp Rating (Lumen)	Desc.	Lamp Wattage	Line Wattage	Est. kWh **	Fixture Charge	Maint. Charge	Energy Charge ***	Total Charge
13000	Acorn	150	190	65	$15.23	$5.48	$1.61	$22.32
13000	Colonial	150	190	65	$4.75	$2.58	$1.61	$8.94
13000	English Coach	150	190	65	$15.57	$5.60	$1.61	$22.78
13000	Destin Single	150	190	65	$33.03	$10.47	$1.61	$45.11
26000	Destin Double	300	380	130	$65.91	$20.12	$3.22	$89.25
33000	Small Flood	350	400	137	$6.76	$3.33	$3.39	$13.46
33000	Shoebox	350	400	137	$8.07	$3.70	$3.39	$15.16
68000	Flood	750	840	288	$6.96	$5.60	$7.14	$19.70

ISSUED BY: S. W. Connally, Jr.

GULF POWER
A SOUTHERN COMPANY

Section No. VI
Twenty-Sixth Revised Sheet No. 6.17
Canceling Twenty-Fifth Revised Sheet No. 6.17

[redacted]

(Continued from Rate Schedule OS, Sheet No. 6.16.1)

Combined High Pressure Sodium/Metal Halide

Initial Lamp Rating (Lumen)	Desc.	Lamp Wattage	Line Wattage	Est. kWh **	Fixture Charge	Maint. Charge	Energy Charge ***	Total Charge
20800	Destin Combo	275	330	113	$49.91	$16.45	$2.80	$69.16

Combined High Pressure Sodium/Metal Halide Pulse Start

Initial Lamp Rating (Lumen)	Desc.	Lamp Wattage	Line Wattage	Est. kWh **	Fixture Charge	Maint. Charge	Energy Charge ***	Total Charge
21800	Destin Combo PS	250	310	106	$57.85	$17.80	$2.63	$78.28

LED

Nominal Delivered Lumen	Desc.	Lamp Wattage	Line Wattage	Est. kWh **	Fixture Charge	Maint. Charge	Energy Charge ***	Total Charge
3776	Acorn	75	75	26	$17.87	$9.23	$0.64	$27.74
4440	Street Light	72	72	25	$13.87	$4.75	$0.62	$19.24
2820	Acorn A5	56	56	19	$25.71	$7.95	$0.47	$34.13
5100	Cobrahead S2	73	73	25	$6.08	$3.97	$0.62	$10.67
10200	Cobrahead S3	135	135	46	$7.49	$4.57	$1.14	$13.20
6320	ATB071 S2/S3	71	71	24	$7.58	$5.16	$0.59	$13.33
9200	ATB1 105 S3	105	105	36	$11.08	$6.22	$0.89	$18.19
23240	ATB2 280 S4	280	280	96	$12.54	$7.24	$2.38	$22.16
7200	E132 A3	132	132	45	$27.75	$8.12	$1.11	$36.98
9600	E157 SAW	157	157	54	$18.78	$5.61	$1.33	$25.72
7377	WP9 A2/S2	140	140	48	$42.20	$13.98	$1.19	$57.37
7614	Destin Single	105	105	36	$32.43	$15.56	$0.89	$48.88
15228	Destin Double	210	210	72	$64.58	$30.89	$1.78	$97.25

ISSUED BY: S. W. Connally, Jr.

GULF POWER
A SOUTHERN COMPANY

Section No. VI
Twenty-Eighth Revised Sheet No. 6.18
Canceling Twenty-Seventh Revised Sheet No. 6.18

[redacted]

(Continued from Rate Schedule OS, Sheet No. 6.17)

Mercury Vapor
(Not Available for New Installations)

Initial Lamp Rating (Lumen)	Desc.	Lamp Wattage	Line Wattage	Est. kWh **	Fixture Charge	Maint. Charge	Energy Charge ***	Total Charge
7000*	Open Bottom	175	195	67	$2.17	$1.34	$1.66	$5.17
3200*	Cobrahead	100	114	39	$4.01	$1.88	$0.96	$6.85
7000*	Cobrahead	175	195	67	$3.64	$1.75	$1.66	$7.05
9400*	Cobrahead	250	277	95	$4.79	$2.14	$2.35	$9.28
17000*	Cobrahead	400	442	152	$5.22	$2.23	$3.76	$11.21
48000*	Cobrahead	1000	1084	372	$10.48	$3.87	$9.20	$23.55
17000*	Directional	400	474	163	$7.86	$2.97	$4.03	$14.86

* Not Available for New Installation.
** Estimated Monthly kWh = (Line Wattage x Annual Operating Hours)/(1000 x 12)
*** Energy Charge = 2.477¢/kWh x Estimated Monthly kWh Usage

ADDITIONAL FACILITIES CHARGES:

The above rates apply to lighting installations made on the Company's existing overhead distribution system. Any special or additional facilities, which may be installed at the Company's option, will be billed in addition to the above rates.

Charge for 13 ft. decorative concrete pole used only for decorative lights (Colonial, Acorn, or English Coach) $17.48.
Charge for 13 ft. decorative high gloss concrete pole used only for decorative lights. (Colonial, Acorn, or English Coach) $15.83.
Charge for 16 ft. decorative base aluminum pole with 6" Tenon used only for decorative lights (Destin Single or Double) $12.54.
Charge for 17 ft. decorative base aluminum pole used only for decorative lights (Colonial, Acorn, or English Coach) $18.31.
Charge for 20 ft. fiberglass pole used only for decorative lights (Colonial) $6.48.
Charge for 20 ft. (16 ft. mounting height) aluminum, round, tapered pole (Spun Tenon) $5.71.
Charge for 20 ft. (16 ft. mounting height) aluminum, round, tapered pole (Welded Tenon) $19.43.
Charge for 25 ft. (20 ft. mounting height) aluminum, round, tapered pole $20.31.
Charge for 30 ft. wood pole $4.19.
Charge for 30 ft. concrete pole $8.79.
Charge for 30 ft. fiberglass pole with concrete, anchor-based pedestal used primarily for the 100,000 Lumen Large Parking Lot fixture $41.64.
Charge for 30 ft. (25 ft. mounting height) aluminum, round, tapered pole $22.53.
Charge for 35 ft. concrete pole $12.82.
Charge for 35 ft. concrete pole (Tenon Top) $17.69.

ISSUED BY: S. W. Connally, Jr.

GULF POWER
A SOUTHERN COMPANY

Section No. VI
Twenty-Fourth Revised Sheet No. 6.19
Canceling Twenty-Third Revised Sheet No. 6.19

(Continued from Rate Schedule OS, Sheet No. 6.18)

ADDITIONAL FACILITIES CHARGES (continued):

Charge for 35 ft. wood pole $6.12.
Charge for 35 ft. (30 ft. mounting height) aluminum, round, tapered pole $25.22.
Charge for 40 ft. wood pole $7.51.
Charge for 45 ft. concrete pole (Tenon Top) $23.22.
Charge for single arm for Shoebox/Small Parking Lot fixture $2.43.
Charge for double arm for Shoebox/Small Parking Lot fixture $2.71.
Charge for triple arm for Shoebox/Small Parking Lot fixture $3.65.
Charge for quadruple arm for Shoebox/Small Parking Lot fixture $4.61.
Charge for Tenon Top adapter for 100,000 Lumen Large Parking Lot fixture $4.50.
Charge for optional 100 amp relay $25.16.
Charge for 25 kVA transformer (non-coastal) for 46,000 Lumen Shoebox, 32,000 Lumen Small Parking Lot, or 100,000 Lumen Large Parking Lot fixture(s) $34.82.
Charge for 25 kVA transformer (coastal) for 46,000 Lumen Shoebox, 32,000 Lumen Small Parking Lot, or 100,000 Lumen Large Parking Lot fixture(s) $49.62.

All other additional facilities shall be billed at 1.74% per month of the Company's cost. Such facilities may include, but are not limited to, additional overhead or underground wiring and special poles approved by the Company.

VANDALISM (WILLFUL DAMAGE):

The Customer will have the following three options on the second occurrence of vandalism (willful damage) to a Company fixture:

1. Pay (a) the total repair costs of the fixture or the original total installed cost of the fixture less any depreciation and salvage value plus the removal cost if the fixture cannot be repaired and (b) the total installed cost of a luminaire protective shield. If the fixture is not compatible with the shield, then the fixture will be replaced with either a compatible 100 watt or 250 watt cobrahead fixture,

2. Request that the damaged fixture be replaced with the same type of unshielded fixture. For this and any subsequent occurrence, the Customer will pay either (a) the total repair costs of the fixture or (b) the original total installed cost of the fixture less any depreciation and salvage value plus the removal cost if the fixture cannot be repaired, or

3. Discontinue the service to the fixture.

The Customer must notify the Company in writing of its selected option. The Customer may choose to pay the total installed cost of a luminaire protective shield after the first occurrence of vandalism (willful damage) to a Company fixture and save the costs incurred in 1(a) above.

ISSUED BY: S. W. Connally, Jr.

GULF POWER
A SOUTHERN COMPANY

Section No. VI
Twenty-Fifth Revised Sheet No. 6.20
Canceling Twenty-Fourth Revised Sheet No. 6.20

(Continued from Rate Schedule OS, Sheet No. 6.19)

MONTHLY RATES - CUSTOMER OWNED WITHOUT RELAMPING SERVICE AGREEMENT:

Customer-owned street, roadway, and general area lighting fixtures which conform to the specifications of Company-owned fixtures may receive energy at the appropriate charges for each size light above. Customer-owned street, roadway, and general area lighting systems which do not conform to specifications of the Company-owned fixtures shall be charged the monthly rate of 2.477¢/kWh of the estimated kWh usage of each unit. Customer-owned equipment must be approved in advance as to accessibility to be eligible to receive service. The Customer will provide all pole(s), fixture(s), lamp(s), photoelectric control(s), and circuit(s) up to the point of connection to the Company's supply lines (point of service), and an adequate support for the Company-owned service conductors. The Company will provide an overhead service drop from its existing secondary conductors to the point of service designated by the Company for Customer-owned lights. Underground service conductors will be installed in lieu of the overhead conductors at the Customer's request, and upon payment by the Customer of the installed cost of the underground conductors after allowance for the cost of equivalent overhead service conductors and any trenching and backfilling provided by the Customer. The distribution system shall serve no other electrical loads except the lighting equipment eligible for this rate.

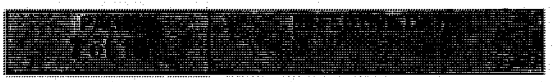
MONTHLY RATES - CUSTOMER OWNED WITH RELAMPING SERVICE AGREEMENT:

The monthly rates set forth below cover both the electric service (if unmetered) and the replacement of lamps and photoelectric controls upon routine failure. Lamps or photoelectric controls damaged or destroyed due to vandalism or willful abuse are not covered by the agreement and will only be replaced at the Customer's expense. Customer-owned equipment must be approved in advance as to compatibility with Company-owned lamps and photoelectric controls and accessibility to be eligible to receive service. The Customer will provide all pole(s), fixture(s), initial lamp(s) and photoelectric control(s), and circuit(s) up to the point of connection to the Company's supply lines (point of service), and an adequate support for the Company-owned service conductors. The Company will provide an overhead service drop from its existing secondary conductors to the point of service designated by the Company for Customer-owned lights. Underground service conductors will be installed in lieu of the overhead conductors at the Customer's request, and upon payment by the Customer of the installed cost of the underground conductors after allowance for the cost of equivalent overhead service conductors and any trenching and backfilling provided by the Customer. The distribution system shall serve no other electrical loads except the lighting equipment eligible for this rate. The Customer remains responsible for all maintenance other than the replacement of lamps and photoelectric controls.

ISSUED BY: S.W. Connally, Jr.

GULF POWER
A SOUTHERN COMPANY

Section No. VI
Twenty-Fifth Revised Sheet No. 6.21
Canceling Twenty-Fourth Revised Sheet No. 6.21



(Continued from Rate Schedule OS, Sheet No. 6.20)

MONTHLY RATES - CUSTOMER OWNED WITH RELAMPING SERVICE AGREEMENT:

High Pressure Sodium Vapor

Initial Lamp Rating (Lumen)	Lamp Wattage	Line Wattage	Est. kWh **	Relamping Charge	Energy Charge ***	Total Charge
8800	100	120	41	$0.69	$1.01	$1.70
6000	150	197	68	$0.68	$1.68	$2.36
20000*	200	233	80	$0.70	$1.98	$2.68
25000	250	292	100	$0.71	$2.48	$3.19
46000	400	477	164	$0.70	$4.05	$4.75
125000	1000	1105	379	$0.89	$9.39	$10.28

Metal Halide

Initial Lamp Rating (Lumen)	Lamp Wattage	Line Wattage	Est. kWh **	Relamping Charge	Energy Charge ***	Total Charge
32000	400	476	163	$0.83	$4.03	$4.86

LED

Initial Lamp Rating (Lumen)	Lamp Wattage	Line Wattage	Est. kWh **	Relamping Charge	Energy Charge ***	Total Charge
4440	72	72	25	$0.78	$0.62	$1.40

* Not Available for New Installation
** Estimated Monthly kWh = (Line Wattage x Annual Operating Hours)/(1000 x 12)
*** Energy Charge = 2.477¢/kWh x Estimated Monthly kWh Usage

The Total Charge shown above is for an unmetered fixture. If the service is metered, there will be no Energy Charge billed under this rate.

ADDITIONAL FACILITIES CHARGES FOR CUSTOMER OWNED:

Any special or additional facilities, which may be installed at the Company's option, will be billed in addition to the above Customer-owned rates.

Charge for 35 ft. wood pole $6.12.

All other additional facilities shall be billed at 1.74 percent per month of the Company's cost.

ISSUED BY: S. W Connally, Jr.

GULF POWER
A SOUTHERN COMPANY

Section No. VI
Twentieth Revised Sheet No. 6.23
Canceling Nineteenth Revised Sheet No. 6.23

(Continued from Rate Schedule OS, Sheet No. 6.22)

OS-III. OTHER OUTDOOR SERVICE (OL1)

Other outdoor service for Customer-owned facilities with fixed wattage loads operating continuously throughout the billing period such as, but not limited to, traffic signals and cable television amplifiers shall be billed according to the monthly rate below:

4.669 cents per kWh for all kWh

The estimated annual kWh usage shall be determined by multiplying the annual operation hours times the maximum demand. The monthly kWh usage will be one-twelfth (1/12) of the estimated annual kWh usage. Maximum demand shall be the total number of kilowatts connected at any one time. At the option of the Company service rendered under this section may be metered and billed under the applicable General Service rate schedule. Minimum Monthly bill shall be $1.00 per service connection.

TERM OF CONTRACT (OS-I/II, OS-III):

Service under this Rate Schedule shall be for an initial period of not less than three (3) years and shall remain until terminated by notice to either party by the other. When additional facilities are required, the Company may require a contract for a longer initial period. There is no term of contract for rate OS-III.

DEPOSIT (OS-I/II, OS-III):

A deposit amounting to not over one-half the billing for the initial contract period may be required before service is connected. The deposit may be applied to any final bills against the Customer for service.

ISSUED BY: S. W. Connally, Jr.

GULF POWER
A SOUTHERN COMPANY

Section No. VI
Tenth Revised Sheet No. 6.42
Canceling Ninth Revised Sheet No. 6.42

RATE SCHEDULE GSTOU
GENERAL SERVICE TIME-OF-USE CONSERVATION (OPTIONAL SCHEDULE)

URSC: GSTOU

[redacted]

AVAILABILITY:

Available on a first come - first serve basis subject to meter availability throughout the entire territory served by the Company.

APPLICABILITY:

Applicable as an option to Rate Schedule GSD for general service on an annual basis covering the entire electrical requirements of any Customer whose highest actual measured demand is not more than four hundred ninety-nine (499) kilowatts. Service to two or more premises shall not be combined nor shall service furnished hereunder be shared with or resold to others. All service shall be taken at the same voltage, from a single delivery point, and shall be measured by a single meter.

CHARACTER OF SERVICE:

The delivery voltage to the Customer shall be the voltage of the available secondary distribution lines of the Company for the locality in which service is to be rendered. Three phase service may be furnished at the request of the Customer subject to the Rules and Regulations of the Company which govern the extension of the three phase service.

MONTHLY RATES:

Base Charge: $45.10

Energy Charges:

Summer – June through September:

On-Peak	19.160¢ per kWh
Intermediate	7.153¢ per kWh
Off-Peak	2.975¢ per kWh

October through May:

All hours	4.164¢ per kWh

ISSUED BY: S. W. Connally, Jr.

GULF POWER
A SOUTHERN COMPANY

Section No. VI
Sixth Revised Sheet No. 6.46
Canceling Fifth Revised Sheet No. 6.46

(Continued from Rate Schedule GSDT, Sheet No. 6.45)

MONTHLY RATES:

Base Charge:	$45.10
Demand Charge:	$3.32 per kW of maximum demand plus; $3.75 per kW of on-peak demand
Energy Charge:	1.793¢ per kWh

CRITICAL PEAK OPTION – Under this option, the Demand Charge shall be:

Demand Charge:	$3.32 per kW of maximum demand plus; $1.88 per kW of on-peak demand plus, $5.63 per kW of critical peak demand

MINIMUM MONTHLY BILLS:

In consideration of the readiness of the Company to furnish such service, no monthly bill will be rendered for less than the Base Charge plus the Demand Charge.

DETERMINATION OF THE ON-PEAK PERIOD:

The on-peak period for calendar months April through October is defined as being those hours between 12:00 p.m. and 9:00 p.m. Central Daylight Time/Central Standard Time, Monday through Friday.

The on-peak period for calendar months November through March is defined as being those hours between 6:00 a.m. and 10:00 a.m. and between 6:00 p.m. and 10:00 p.m. Central Standard Time/Central Daylight Time, Monday through Friday.

ISSUED BY: S. W. Connally, Jr.

GULF POWER
A SOUTHERN COMPANY

Section No. VI
Fifth Revised Sheet No. 6.48
Canceling Fourth Revised Sheet No. 6.48

(Continued from Rate Schedule GSDT, Sheet No. 6.47)

TRANSFORMER OWNERSHIP DISCOUNT AND PRIMARY METERING VOLTAGE DISCOUNTS:

When the Company renders service under this Rate Schedule at the local primary distribution voltage and any transformers required are furnished by the Customer, the Monthly Rate will be subject to a discount of forty (40) cents per kW of the Customer's Maximum Demand as determined above, and an additional discount of one percent (1%) of the Energy Charge and one percent (1%) of the Demand Charge; however, such deduction shall not reduce the minimum monthly bill specified above.

CRITICAL PEAK DEMAND NOTIFICATION

A customer electing the critical peak option will be notified of a critical peak period one business day prior to the beginning of the critical peak period event. The Company is not responsible for a customer's failure to receive and act upon the critical peak period. If a customer does not receive these notifications, it is the customer's responsibility to inform the Company so the notifications may be supplied.

TERM OF CONTRACT:

(1) Service under this Schedule shall be for a period of not less than one year and thereafter from year to year until terminated by three (3) months' written notice by either party to the other.

(2) The initial selection of this optional rate schedule by a Rate Schedule GSD Customer may be terminated at any time by written or personal notice from the Customer. After such termination, any subsequent selection of this option by the same Customer for service at the same premises shall have a term of contract as specified in (1) above.

ISSUED BY: S. W. Connally, Jr.

GULF POWER
A SOUTHERN COMPANY

Section No. VI
Sixth Revised Sheet No. 6.49
Canceling Fifth Revised Sheet No. 6.49

RATE SCHEDULE LPT
LARGE POWER SERVICE – TIME-OF-USE CONSERVATION (OPTIONAL SCHEDULE)

URSC: GSLDT

[redacted]

AVAILABILITY:

Available on a first come - first serve basis subject to meter availability throughout the entire territory served by the transmission system of the Company.

APPLICABILITY:

Applicable as an option to Rate Schedule LP for three phase general service on an annual basis covering the entire electrical requirements of any Customer. Service to two or more premises shall not be combined nor shall service furnished hereunder be shared with or resold to others. All service shall be taken at the same voltage, from a single delivery point, and shall be measured by a single meter. Customers taking service under Rate LPT may elect the critical peak option.

CHARACTER OF SERVICE:

The delivery voltage to the Customer shall be the voltage of the available secondary distribution lines of the Company for the locality in which service is to be rendered.

MONTHLY RATES:

Base Charge:	$260.00
Demand Charge:	$2.64 per kW of maximum demand plus; $10.22 per kW of on-peak demand
Energy Charge:	0.970¢ per kWh

ISSUED BY: S. W. Connally, Jr.

GULF POWER
A SOUTHERN COMPANY

Section No. VI
Fourth Revised Sheet No. 6.50
Canceling Third Sheet No. 6.50

[redacted]

(Continued from Rate Schedule LPT, Sheet No. 6.49)

CRITICAL PEAK OPTION –Under this option, the Demand Charge shall be:

Demand Charge:	$2.64 per kW of maximum demand plus; $5.11 per kW of on-peak demand plus, $15.32 per kW of critical peak demand

MINIMUM MONTHLY BILLS:

In consideration of the readiness of the Company to furnish such service, no monthly bill shall be rendered for less than the Base Charge plus the Demand Charge.

DETERMINATION OF THE ON-PEAK PERIOD:

The on-peak period for calendar months April through October is defined as being those hours between 12:00 p.m. and 9:00 p.m. Central Daylight Time/Central Standard Time, Monday through Friday.

The on-peak period for calendar months November through March is defined as being those hours between 6:00 a.m. and 10:00 a.m. and between 6:00 p.m. and 10:00 p.m. Central Standard Time/Central Daylight Time, Monday through Friday.

DETERMINATION OF THE OFF-PEAK PERIOD:

All hours not included above and all hours of the observed holidays of New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving, and Christmas are in the off-peak period.

DETERMINATION OF CRITICAL PEAK PERIOD:

A critical peak period may be designated at any time at the Company's discretion. The duration of any single critical peak period may range from 1 to 2 hours in length. The total number of hours designated as critical peak periods may not exceed 87 hours per year. The total number of critical peak periods may not exceed one per day, and may not exceed four per week. Conditions which may result in the designation of a critical peak period by the Company include, but are not limited to: (i) A temperature forecast for the Company's service area that is above 95°F or below 32°F; (ii) Real-Time-Prices that exceed certain thresholds; (iii) Projections of system peak loads that exceed certain thresholds.

ISSUED BY: S. W. Connally, Jr.

GULF POWER
A SOUTHERN COMPANY

Section No. VI
Fourth Revised Sheet No. 6.51
Canceling Third Revised Sheet No. 6.51

(Continued from Rate Schedule LPT, Sheet No. 6.50)

DETERMINATION OF BILLING DEMAND:

(a) Maximum Demand--The kilowatt (kW) billing demand for billing purposes shall be the Customer's maximum integrated 15 minute demand to the nearest kilowatt (kW) during each service month.

(b) On-Peak Demand--The kilowatt (kW) billing demand for billing purposes shall be the Customer's maximum integrated 15 minute demand to the nearest kilowatt (kW) during each service month as measured during the hours designated as on-peak.

(c) Critical Peak Demand -- The kilowatt (kW) billing demand for billing purposes shall be the Customer's maximum integrated 15 minute demand to the nearest kilowatt (kW) during each service month as measured during the hours designated as critical peak.

REACTIVE DEMAND CHARGE:

The monthly bill calculated at the above rates may be increased in the amount of $1.00 per kvar for all over 0.48432 kilovars per kilowatt (90% power factor). The kilovars to which this adjustment shall apply shall be the monthly maximum measured kilovar demand or may be calculated as the square root of the difference between the square of the maximum monthly measured kVA demand and the square of the maximum monthly measured kW demand.

TRANSFORMER OWNERSHIP DISCOUNT AND PRIMARY METERING VOLTAGE DISCOUNTS:

When the Company renders service under this Rate Schedule at the local primary distribution voltage and any transformers required are furnished by the Customer, the Monthly Rate will be subject to a discount of fifty-seven (57) cents per month per kilowatt (kW) of the Customer's highest billing demand as determined above, and an additional discount of one percent (1%) of the Energy Charge and one percent (1%) of the Demand Charge; however, such deduction shall not reduce the minimum monthly bill specified above.

ISSUED BY: S. W. Connally, Jr.

GULF POWER
A SOUTHERN COMPANY

Section No. VI
Fourth Revised Sheet No. 6.52
Canceling Third Revised Sheet No. 6.52

(Continued from Rate Schedule LPT, Sheet No. 6.51)

TRANSFORMER OWNERSHIP DISCOUNT AND TRANSMISSION METERING VOLTAGE DISCOUNTS:

When the Company renders service under this Rate Schedule from an available transmission line of 46,000 volts or higher and the Customer furnishes, operates, and maintains the complete step-down transformer substation necessary to receive and use such service, the Monthly Rate will be subject to a discount of eighty-one (81) cents per month per kilowatt (kW) of the Customer's highest billing demand as determined above, and an additional discount of two percent (2%) of the Energy Charge and two percent (2%) of the Demand Charge; however, such deduction shall not reduce the minimum monthly bill specified above.

DEPOSIT:

A deposit amounting to twice the estimated average monthly bill may be required before service is connected at designated premises. The deposit may be applied to any final bills against the Customer for service.

CRITICAL PEAK DEMAND NOTIFICATION

A customer electing the critical peak option will be notified of a critical peak period one business day prior to the beginning of the critical peak period event. The Company is not responsible for a customer's failure to receive and act upon the critical peak period. If a customer does not receive these notifications, it is the customer's responsibility to inform the Company so the notifications may be supplied.

TERM OF CONTRACT:

(1) Service under this Schedule shall be for a period of not less than one year and thereafter from year to year until terminated by three (3) months' written notice by either party to the other.

(2) The initial selection of this rate schedule as an option by a Rate Schedule LP Customer may be terminated at any time by written or personal notice from the Customer. After such termination, any subsequent selection of this option by the same Customer for service at the same premises shall have a term of contract as specified in (1) above.

ISSUED BY: S. W. Connally, Jr.

GULF POWER
A SOUTHERN COMPANY

Section No. VI
Sixth Revised Sheet No. 6.53
Canceling Fifth Revised Sheet No. 6.53

RATE SCHEDULE PXT
LARGE HIGH LOAD FACTOR POWER SERVICE
TIME-OF-USE CONSERVATION
(OPTIONAL SCHEDULE)

URSC: GSLDT1

[redacted]

AVAILABILITY:

Available throughout the entire territory served by the transmission system of the Company.

APPLICABILITY:

Applicable as an option to Rate Schedule PX for three phase lighting and power service to any customer whose actual measured demand is not less than 7,500 kilowatts (kW), with an annual load factor of not less than seventy-five percent (75%). Service to two or more premises shall not be combined nor shall service furnished hereunder be shared with or resold to others. All service shall be taken at the same voltage and from a single delivery point, and shall be measured by a single meter.

CHARACTER OF SERVICE:

The delivery voltage to the Customer shall be the standard secondary voltage of the Company's transformers supplied from the transmission lines of the Company.

MONTHLY RATES:

Base Charge:	$764.56
Demand Charge:	$0.93 per kW of maximum demand plus; $10.36 per kW of on-peak demand
Energy Charge:	On-Peak and Off-Peak Period: 0.410¢ per kWh

ISSUED BY: S. W. Connally, Jr.

GULF POWER
A SOUTHERN COMPANY

Section No. VI
Sixth Revised Sheet No. 6.54
Canceling Fifth Revised Sheet No. 6.54

(Continued from Rate Schedule PXT, Sheet No. 6.53)

DETERMINATION OF THE ON-PEAK PERIOD:

The on-peak period for calendar months April through October is defined as being those hours between 12:00 p.m. and 9:00 p.m. Central Daylight Time/Central Standard Time, Monday through Friday.

The on-peak period for calendar months November through March is defined as being those hours between 6:00 a.m. and 10:00 a.m. and between 6:00 p.m. and 10:00 p.m. Central Standard Time/Central Daylight Time, Monday through Friday.

DETERMINATION OF THE OFF-PEAK PERIOD:

All hours not included above and all hours of the observed holidays of New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving, and Christmas are in the off-peak period.

MINIMUM MONTHLY BILLS:

In the event the Customer's annual load factor for the current and preceding eleven months is less than 75% and in consideration of the readiness of the Company to furnish such service, the minimum monthly bill shall not be less than the Base Charge plus $13.53 per kW of maximum billing demand.

DETERMINATION OF BILLING DEMAND:

(a) Maximum Demand--The kilowatt (kW) billing demand for billing purposes shall be the maximum measured kw demand integrated over any fifteen minute interval during the current bill month but not less than 7500 kW.

(b) On-Peak Demand--The kilowatt (kW) billing demand for billing purposes shall be the customer's maximum integrated 15 minute demand to the nearest kilowatt (kW) during each service month as measured during the hours designated as on-peak.

REACTIVE DEMAND CHARGE:

The monthly bill calculated at the above rates shall also be increased in the amount of $1.00 per kvar for all over 0.48432 kilovars per kilowatt (90% power factor). The kilovars to which this adjustment shall apply shall be the monthly maximum measured kilovar demand or may be calculated as the square root of the difference between the square of the maximum monthly measured kVA demand and the square of the maximum monthly measured kW demand.

ISSUED BY: S. W. Connally, Jr.

GULF POWER
A SOUTHERN COMPANY

Section No. VI
Sixth Revised Sheet No. 6.59
Canceling Fifth Revised Sheet No. 6.59

[redacted]

(Continued from Rate Schedule SBS, Sheet No. 6.58)

A Standby Service Customer will be billed for electric service in accordance with the following charges:

Contract Demand:	100 to 499 kW	500 to 7,499 kW	Above 7,499 kW
Base Charge:	$258.18	$258.18	$614.77
Demand Charge:			
Local Facilities Charge Per kW of BC and NC	$2.77	$2.44	$1.08
On-Peak Demand Charge: Per kW of On-Peak kW up to NC	$3.81	$10.24	$10.47
Plus the greater of:			
Reservation Charge: Per kW of BC or	$1.23	$1.23	$1.26
The Sum of the Daily On-Peak Standby Demand Charges: Per kW per day of On-Peak kW in excess of NC	$0.58	$0.58	$0.59
Energy Charge Per kWh:	3.599¢	3.599¢	3.599¢

Customers with zero (0) NC will not be subject to the On-Peak Demand Charge.

ISSUED BY: S. W. Connally, Jr

GULF POWER
A SOUTHERN COMPANY

Section No. VI
Seventh Revised Sheet No. 6.76
Canceling Sixth Revised Sheet No. 6.76

(Continued from Rate Schedule RSVP, Sheet No. 6.75)

If a Customer moves into a residence with existing Company-owned energy management equipment, the Customer will receive service under Rate Schedule RSVP. The Customer will be given the option of remaining on Rate Schedule RSVP or moving to Rate Schedule RS. If the Customer chooses Rate Schedule RS at that time, Company-owned energy management equipment will be removed free of charge.

CHARACTER OF SERVICE:

Available for single-phase service from local distribution lines of the Company's system at nominal secondary voltage of 120/240 volts. Service shall be metered through one metering device capable of measuring electrical energy consumption during the various times each energy demand charge is in effect.

RATES:

Base Charge: $0.62 per day

Energy Demand Charge:

Low Cost Hours (P_1):	5.018¢ per kWh
Medium Cost Hours (P_2):	5.018¢ per kWh
High Cost Hours (P_3):	5.018¢ per kWh
Critical Cost Hours (P_4):	5.018¢ per kWh

ISSUED BY: S. W. Connally, Jr.

Section VII
Eighth Revised Sheet No. 7.13
Canceling Seventh Revised Sheet No. 7.13

GULF POWER COMPANY
OUTDOOR SERVICE - LIGHTING PRICING METHODOLOGY
MONTHLY RATES - Rate Schedule OS (Part I/II)
Form 4

SECTION A - LED FIXTURES

Total Unit Cost	
Fixture Cost	$0.00
Arm Cost	$0.00
Bulb Cost	$0.00
Photocell Cost	$0.00
SUBTOTAL	$0.00
0.000 Man-hours to Install Fixture/Arm (If Applicable) @ $53.28/Manhour	$0.00
SUBTOTAL	$0.00
36.0% Engineering & Supervision Overheads	$0.00
UNIT COST TOTAL	$0.00
Fixture Charge	
Fixed Charge = (15.235% x Unit Cost Total)/12 Months	$0.00
Revenue Tax = Fixed Charge x 0.000721	$0.00
FIXTURE CHARGE	**$0.00**
Maintenance Charge	
Average Annual Bulb Failure Rate : 0.0%	
Bulb Life (in hours) Failure Rate = (Ann. Burn Hrs / Bulb Life)	
Annual Burn hours	
Photocell Replacement = (Photocell Cost + Labor) x Photocell Failure Rate/12 Months	$0.00
Photocell Life (in hours) Failure Rate = (Ann. Burn Hrs / Photocell Life)	
$0 Photocell Cost = 0	
Photocell Replacement Labor Hrs	
Driver Replacement = (Driver Cost + Labor) x Driver Failure Rate/12 Months	$0.00
Driver Life (in hours) Failure Rate = (Ann. Burn Hrs / Driver Life)	
$0 Driver Cost = 0	
Driver Replacement Labor Hrs	
Surge Protection Device (SPD) Replacement = (SPD Cost + Labor) x SPD Failure Rate/12 Months	$0.00
SPD Life (in hours) Failure Rate = (Ann. Burn Hrs / SPD Life)	
$0 SPD Cost = 0	
SPD Replacement Labor Hrs	
Luminaire Repair Cost =	
[Man-hours to Remove of 0.36 @ $53.28/Manhour + Unit Cost Total]	
x 6.7% Annual Luminaire Failure Rate/12 Months	$0.00
SUBTOTAL	$0.00
Revenue Tax = Subtotal x 0.000721	$0.00
MAINTENANCE CHARGE	**$0.00**
Energy Charge	
0 Line Wattage x 4,120 Annual Operating Hours/(1,000 x 12) =	
0 kWh @ $0.02477/kWh **ENERGY CHARGE**	**$0.00**

PRICE SUMMARY	
Fixture Charge	$0.00
Maintenance Charge	$0.00
Energy Charge	$0.00
TOTAL MONTHLY CHARGE PER FIXTURE	**$0.00**

ISSUED BY: S. W. Connally, Jr.

EFFECTIVE:

Section VII
First Revised Sheet No. 7.13.1
Canceling Original Sheet No. 7.13.1

Form 4 (Continued)

SECTION A-1 - Non-LED FIXTURES

Total Unit Cost	
Fixture Cost	$0.00
Arm Cost	$0.00
Bulb Cost	$0.00
Photocell Cost	$0.00
SUBTOTAL	$0.00
0.000 Man-hours to Install Fixture/Arm (If Applicable) @ $53.28/Manhour	$0.00
SUBTOTAL	$0.00
36.0% Engineering & Supervision Overheads	$0.00
UNIT COST TOTAL	$0.00
Fixture Charge	
Fixed Charge = (15.235% x Unit Cost Total)/12 Months	$0.00
Revenue Tax = Fixed Charge x 0.000721	$0.00
FIXTURE CHARGE	**$0.00**
Maintenance Charge	
Average Annual Bulb Failure Rate : 0.0%	
Bulb Life (in hours) / Annual Burn hours — Failure Rate = (Ann. Burn Hrs / Bulb Life)	
Spot Rebulb Cost = (Bulb Cost + Photocell Cost + $29 Labor) x Bulb Failure Rate/12 Months	$0.00
Luminaire Repair Cost = [Man-hours to Remove of 0.36 @ $53.28/Manhour + Unit Cost Total] x 6.7% Annual Luminaire Failure Rate/12 Months	$0.00
SUBTOTAL	$0.00
Revenue Tax = Subtotal x 0.000721	$0.00
MAINTENANCE CHARGE	**$0.00**
Energy Charge	
Line Wattage x 4,120 Annual Operating Hours/(1,000 x 12) = 0 kWh @ $0.02477/kWh	
ENERGY CHARGE	**$0.00**

PRICE SUMMARY	
Fixture Charge	**$0.00**
Maintenance Charge	**$0.00**
Energy Charge	**$0.00**
TOTAL MONTHLY CHARGE PER FIXTURE	**$0.00**

ISSUED BY: S. W. Connally, Jr.

EFFECTIVE:

Section VII
Eighth Revised Sheet No. 7.15
Canceling Seventh Revised Sheet No. 7.15

Form 4 (Continued)

SECTION C - RELAMPING SERVICE AGREEMENT

Bulb and Photocell Cost	
Bulb Cost	$0.00
Photocell Cost	$0.00
BULB AND PHOTOCELL COST	$0.00
Relamping Charge	
Average Annual Bulb Failure Rate : 0.0%	
Bulb Life (in hours) Failure Rate = (Ann. Burn Hrs / Bulb Life)	
Annual Burn hours	
Spot Rebulb Cost =(Bulb Cost + Photocell Cost + $29 Labor) x Bulb Failure Rate/12 Months	$0.00
SUBTOTAL	$0.00
Revenue Tax = Subtotal x 0.000721	$0.00
RELAMPING CHARGE	**$0.00**
Energy Charge	
0 Line Wattage x 4,120 Annual Operating Hours/(1,000 x 12) =	
0 kWh @ $0.02477/kWh **ENERGY CHARGE**	**$0.00**

PRICE SUMMARY	
Relamping Charge	**$0.00**
Energy Charge	**$0.00**
TOTAL MONTHLY CHARGE PER FIXTURE	**$0.00**

ISSUED BY: S. W. Connally, Jr.

EFFECTIVE:

Section VII
Ninth Revised Sheet No. 7.45
Canceling Eighth Revised Sheet No. 7.45

GULF POWER COMPANY
OPTIONAL RELAMPING SERVICE AGREEMENT
CUSTOMER-OWNED STREET AND GENERAL AREA LIGHTING
RATE SCHEDULE OS (PART I/II)
Form 19

Contract No. _____

Customer Name _____ Date _____

DBA _____ Telephone No. _____ Tax I. D.. _____

Street Address (Subdivision, etc.) of Light(s) _____

Mailing Address _____

Driving Directions _____

_____

Location of Light(s) _____
Meter No. _____ Account No. _____ JETS WO No. _____

UNMETERED CUSTOMER-OWNED FIXTURES:
High Pressure Sodium Vapor Lighting:

_____ 8,800 Lumen (100 Watts) Light(s) to be billed at a base rate of $1.70 each per month	$ _____
_____ 16,000 Lumen (150 Watts) Light(s) to be billed at a base rate of $2.36 each per month	$ _____
_____ 20,000 Lumen (200 Watts) Light(s) to be billed at a base rate of $2.68 each per month	$ _____
_____ 25,000 Lumen (250 Watts) Light(s) to be billed at a base rate of $3.19 each per month	$ _____
_____ 46,000 Lumen (400 Watts) Light(s) to be billed at a base rate of $4.75 each per month	$ _____
_____ 125,000 Lumen (1000 Watts) Light(s) to be billed at a base rate of $10.28 each per month	$ _____

Metal Halide Lighting:

_____ 32,000 Lumen (400 Watts) Light(s) to be billed at a base rate of $4.86 each per month	$ _____

METERED CUSTOMER-OWNED FIXTURES:
High Pressure Sodium Vapor Lighting:

_____ 8,800 Lumen (100 Watts) Light(s) to be billed at a base rate or $0.69 each per month	$ _____
_____ 16,000 Lumen (150 Watts) Light(s) to be billed at a base rate of $0.68 each per month	$ _____
_____ 20,000 Lumen (200 Watts) Light(s) to be billed at a base rate of $0.70 each per month	$ _____
_____ 25,000 Lumen (250 Watts) Light(s) to be billed at a base rate or $0.71 each per month	$ _____
_____ 46,000 Lumen (400 Watts) Light(s) to be billed at a base rate or $0.70 each per month	$ _____
_____ 125,000 Lumen (1000 Watts) Light(s) to be billed at a base rate of $0.89 each per month	$ _____

Metal Halide Lighting:

_____ 32,000 Lumen (400 Watts) Light(s) to be billed at a base rate or $0.83 each per month	$ _____
Total Base Monthly Charge*	$ _____

*Base monthly charge does not include Fuel Charge, Purchased Power Capacity Charge, Environmental Charge, Energy Conservation Charge, Natural Disaster Recovery Surcharge, applicable taxes, or fees.

The Applicant requests a relamping service agreement on the lamp(s) and photocell(s) for the fixtures described above and the necessary electric energy (if unmetered) for the operation thereof and hereby agrees to take and pay for the same in accordance with and subject to the Company's Rate Schedule "OS (PART I/II)" and Rules and Regulations for Electric Service on file in its office and on file with the Florida Public Service Commission or any changes therein as approved by the Florida Public Service Commission. This agreement and the monthly rates set forth above cover both the electric service (if unmetered) and the replacement of lamps and photoelectric controls upon routine failure. Lamps or photoelectric controls damaged or destroyed due to vandalism or willful abuse are not covered by this agreement and will only be replaced at the Applicant's expense. The Applicant remains responsible for all maintenance other than the replacement of lamps and photoelectric controls. The distribution system shall serve no other electrical loads except the lighting equipment described above.

ISSUED BY: S. W. Connally, Jr. EFFECTIVE:

Section VII
Eighth Revised Sheet No. 7.55
Canceling Seventh Revised Sheet No. 7.55

GULF POWER COMPANY
CUSTOMER-OWNED LIGHTING AGREEMENT
(WITHOUT RELAMPING SERVICE PROVISIONS)
RATE SCHEDULE OS (PART I/II)

Form 24

Contract No. _____

Customer Name _____ Date _____

DBA _____ Telephone No. _____ Tax I. D. _____

Street Address (Subdivision, etc.) of Light(s) _____

Billing Address _____

Driving Directions _____

No. of Light(s) _____ Location of Light(s) _____

Meter No. _____ Account No. _____

JETS WO No. _____ **CUSTOMER-OWNED FIXTURE(S):**

High Pressure Sodium

_____ 8800 Lumen (100 Watts) Light(s) to be billed at a base rate of $1.01 each per month $_____
_____ 25000 Lumen (250 Watts) Light(s) to be billed at a base rate of $2.48 each per month $_____
_____ 46000 Lumen (400 Watts) Light(s) to be billed at a base rate of $4.05 each per month $_____
_____ 125000 Lumen (1000 Watts) Light(s) to be billed at a base rate of $9.39 each per month $_____

Metal Halide

_____ 12000 Lumen (175 Watts) Light(s) to be billed at a base rate of $1.78 each per month $_____
_____ 13000 Lumen (150 Watts PS) Light(s) to be billed at a base rate of $1.61 each per month $_____
_____ 32000 Lumen (400 Watts) Light(s) to be billed at a base rate of $4.03 each per month $_____
_____ 100000 Lumen (1000 Watts) Light(s) to be billed at a base rate of $9.34 each per month $_____

All others to be billed as follows:

_____ Light(s) @ a base rate of $_____ * each per month (kWh for one light = _____) $_____
_____ Light(s) @ a base rate of $_____ * each per month (kWh for one light = _____) $_____
_____ Light(s) @ a base rate of $_____ * each per month kWh for one light = _____) $_____
Total Base Monthly Charge** $_____

* This base rate per light is calculated by taking the kWh for one light and multiplying by $0.02477/kWh. Repeat this line for each different type of customer-owned light other than the 8800 Lumen, 12000 Lumen, 13000 Lumen, 25000 Lumen, 32000 Lumen, 46000 Lumen, 100000 Lumen, or 125000 Lumen lights shown above.

** Base monthly charge does not include Fuel Charge, Purchased Power Capacity Charge, Environmental Charge, Energy Conservation Charge, Natural Disaster Recovery Surcharge, applicable taxes, or fees.

The Applicant requests the necessary electric energy for the operation thereof for the fixtures described above and hereby agrees to take and pay for the same in accordance with and subject to the Company's Rate Schedule "OS (PART I/II)" and Rules and Regulations for Electric Service on file in its office and on file with the Florida Public Service Commission or any changes therein as approved by the Florida Public Service Commission. This agreement and the monthly rates set forth above cover the electric service. The distribution system shall serve no other electrical loads except the lighting equipment described above.

ISSUED BY: S. W. Connally, Jr. EFFECTIVE:

MARK E. GARRETT

CONTACT INFORMATION:
11713 N.W. 120th Street
Yukon, OK 73099
(405) 239-2226

EDUCATION:
Juris Doctor Degree, With Honors, Oklahoma City University Law School, 1997
Post Graduate Hours in Accounting, Finance and Economics, 1984-85:
University of Texas at Arlington
University of Texas at Pan American
Stephen F. Austin State University
Bachelor of Arts Degree, University of Oklahoma, 1978

CREDENTIALS:
Member Oklahoma Bar Association, 1997, License No. 017629
Certified Public Accountant in Oklahoma, 1992, Certificate No. 11707-R
Certified Public Accountant in Texas, 1986, Certificate No. 48514

WORK HISTORY:

CONSULTING PRACTICE (1996 - Present) Participate as a consultant and expert witness in electric utility, natural gas distribution company, and natural gas pipeline matters before regulatory agencies making recommendations related to cost-based rates. Review management decisions of regulated utility companies for reasonableness from a ratemaking perspective, especially in proceedings to review the reasonableness of prices paid for natural gas supplies and transportation, coal supplies and transportation, purchased power and renewable energy projects. Participate in gas gathering, gas transportation, gas contract and royalty valuation disputes to determine pricing and damage calculations and to make recommendations concerning the reasonableness of charges to royalty and working interest owners and other interested parties. Participate in regulatory proceedings to restructure the electric and natural gas utility industries. Also participate as an Instructor at NMSU Center for Public Utilities and as a Speaker at NARUC Staff Subcommittee on Accounting and Finance.

OKLAHOMA CORPORATION COMMISSION – Aide to Commissioner Bob Anthony (1995)

OKLAHOMA CORPORATION COMMISSION - Coordinator of Accounting and Financial Analysis (1991 - 1994) Planned and supervised the audits of major public utility companies doing business Oklahoma for the purpose of determining revenue requirements. Presented both oral and written testimony as an expert witness for Staff in defense of numerous accounting and financial recommendations related to cost-of-service based rates. Audit work and testimony covered all areas of rate base and operating expense. Supervised, trained and reviewed the audit work of numerous Staff CPAs and auditors. Promoted from Supervisor of Audits to Coordinator in 1992.

FREEDOM FINANCIAL CORPORATION - Controller for Real Estate Development Company with $300 million in assets (1987 - 1990) Responsible for all financial reporting including monthly and annual financial statements, cash flow statements, budget reports, long-term financial planning, tax planning and personnel development. Managed the General Ledger and Accounts Payable departments and supervised a staff of seven CPAs and accountants. Reviewed all subsidiary state and federal tax returns and facilitated the annual independent financial audit and all state or federal tax audits. Received promotion from Assistant Controller in September 1988.

SHELBY, RUCKSDASHEL & JONES, CPA's - Auditor (1986 - 1987) Audited the financial statements of businesses in the state of Texas, with an emphasis in financial institutions.

Previous Experience Related to Cost-of-Service, Rate Design, Pricing and Energy-Related Issues

1. **Entergy Texas Inc., 2013 (PUC Docket No. 49791) –** Participating as an expert witness on behalf of the Cities[1] in ETI's general rate case to provide testimony on various cost of service issues and on the utility's overall revenue requirement.

2. **NV Energy, Inc., 2013 (Docket No. 13-07021**) – Participating as an expert witness in the MidAmerican/NVE merger and acquisition docket on behalf of the Southern Nevada Hotel Group[2] before the Public Utility Commission of Nevada to provide testimony regarding the merger in general and the requested acquisition premium in particular.

3. **Entergy Arkansas, 2013 (Docket No. 13-028-U) –** Participating as an expert witness on behalf of the Hospital and Higher Education Consumers ("HHEC") an intervener group that includes the University of Arkansas and several hospitals before the Arkansas PSC in Entergy's general rate case to provide testimony on various revenue requirement issues.

4. **Sierra Pacific Power Company, 2013 (Docket No. 13-06002) –** Participating as an expert witness on behalf of the Northern Nevada Utility Customers before the Nevada PUC in SPPC's general rate case proceeding to provide testimony on various cost of service and revenue requirement issues.

5. **Sierra Pacific Power Company, 2013 (Docket No. 13-06004) –** Participating as an expert witness on behalf of the Northern Nevada Utility Customers before the Nevada PUC in SPPC's application for new depreciation rates to provide testimony on the Company's excess depreciation reserve to address how the excess reserve should be treated for ratemaking purposes.

6. **Gulf Power Company, 2013 (Docket No. 130140-EI) –** Participating as an expert witness on behalf of the Office of Public Counsel before the Florida Commission in Gulf Power's general rate case proceeding to provide testimony on various revenue requirement issues.

7. **Public Service Company of Oklahoma, 2012 (Cause No. PUD 201200054) –** Participating as an expert witness on behalf of the Oklahoma Industrial Energy Consumers ("OIEC")[3] before the Oklahoma Corporation Commission ("OCC") to provide testimony in PSO's application seeking Commission approval of its settlement agreement with EPA.

8. **Southwestern Electric Power Company, 2012 (PUC Docket No. 40443) –** Participated as an expert witness on behalf of Cities Advocating Reasonable Deregulation ("CARD Cities") before the Texas Public Utility Commission in SWEPCO's general rate case proceeding to provide testimony on various cost of service issues and on the utility's overall revenue requirement.

9. **Doyon Utilities, 2012 Alaska Rate Case** (Docket No. TA7-717) – Participated as an expert witness consultant on behalf of the Department of Defense to provide expert testimony in twelve rate case reviews for the utility systems of Fort Wainwright, Fort Greely and Joint Base Elmendorf-Richardson before the Regulatory Commission of Alaska.

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1 Beaumont, Conroe, Groves, Houston, Huntsville, Orange, Navasota, Nederland, Pine Forest, Pinehurst, Port Arthur, Port Neches, Rose City, Shenandoah, Silsbee, Sour Lake, Vidor, and West Orange

2 The Southern Nevada Hotel Group is comprised of Boyd Gaming, Caesars Entertainment, MGM Resorts, Station Casinos, Venetian Casino Resort, and Wynn Las Vegas.

3 OIEC is an association of approximately 25 large industrial manufacturing facilities in Oklahoma.

Garrett Group, LLC
1400 First National Center
120 North Robinson Ave.
Oklahoma City, OK 73102
(405) 239-2226/ mgarrett@garrettgroupllc.com

10. **University of Oklahoma, 2012** – Participated as an expert witness on behalf of the University of Oklahoma to provide expert testimony on various revenue requirement issues in the University's general rate case with the Corix Group, which provides utility services to the University.

11. **Public Service Company of Oklahoma, 2012 (Cause No. PUD 201200079) –** Participated as an expert witness on behalf of the OIEC before the Oklahoma Corporation Commission to provide expert testimony addressing the utility's request to earn additional compensation on a 510MW purchased power agreement with Exelon

12. **Centerpoint Energy Texas Gas, 2012 (Docket No.** GUD 10182) – Participated as an expert witness on behalf of the Steering Committee of Cities before the Texas Railroad Commission to provide expert testimony on various revenue requirement issues.

13. **Entergy Texas Inc., 2012 (PUC Docket No. 39896) –** Participating as an expert witness on behalf of the Cities[4] in ETI's general rate case to provide testimony on various cost of service issues and on the utility's overall revenue requirement.

14. **Oklahoma Natural Gas Company, 2012 (Cause No. PUD 2012-029)** – Participating as an expert witness on behalf of the OIEC before the OCC in ONG's Performance Based Rate ("PBR") application seeking Commission approval of a requested rate increase based upon formula results for 2011.

15. **University of Oklahoma, 2012** – Assisted the University of Oklahoma with an audit of the costs associated with its six utility operations and its contract with the Corix Group to provide utility services to the university.

16. **Oklahoma Gas and Electric Company, 2012 (Cause No. PUD 2011-186)** – Participating as an expert witness on behalf of the OIEC before the OCC in OG&E's application seeking Commission approval of a special contract with Oklahoma State University and a wind energy purchase agreement in connection therewith.

17. **Empire Electric Company, 2011, (Cause No. PUD 11-082)** – Participated as an expert witness on behalf of Enbridge before the OCC in Empire's rate case to provided testimony in both the revenue requirement and rate design phases of the proceedings to establish prospective cost-of-service based rates for the power company.

18. **Nevada Power Company, 2011, (Docket No. 11-04010)** - Participated as an expert witness on behalf of the Southern Nevada Hotel Group ("SNHG") before the Nevada PUC to sponsored written and oral testimony to address proposed changes to the Company's customer deposit rules.

19. **Nevada Power Company, 2011, (Docket No. 11-06006)** - Participated as an expert witness on behalf of the Southern Nevada Hotel Group before the Nevada PUC to sponsored written and oral testimony in both the revenue requirement phase and the rate design phase of the proceedings to establish prospective cost-of-service based rates for the power company.

20. **Public Service Company of Oklahoma, 2011 (Cause No. PUD 2011-106)** – Participated as an expert witness on behalf of the OIEC before the OCC in PSO's application seeking rider recovery of third party SPP transmission costs and fees.

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4 Beaumont, Conroe, Groves, Houston, Huntsville, Orange, Navasota, Nederland, Pine Forest, Pinehurst, Port Arthur, Port Neches, Rose City, Shenandoah, Silsbee, Sour Lake, Vidor, and West Orange

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21. **Oklahoma Gas and Electric Company, 2011 (Cause No. PUD 2011-087) –** Participating as an expert witness on behalf of OIEC before the OCC in OG&E's rate case to provided testimony in both the revenue requirement and rate design phases of the proceedings to establish prospective cost-of-service based rates for the power company.

22. **Oklahoma Gas & Electric Company, 2011 (Docket No. 10-109-U)** – Participated as an expert witness on behalf of Gerdau Macsteel before the Arkansas Public Service Commission in OG&E's application to recover Smart Grid costs to make recommendations regarding the allocation of the Smart Grid costs.

23. **Oklahoma Gas & Electric Company, 2011 (Cause No. PUD 2011-027)** – Participated as an expert witness on behalf of the OIEC before the OCC in OG&E's application seeking to include retire medical expense in the Company's pension tracker mechanism.

24. **Public Service Company of Oklahoma, 2011 (Cause No. PUD 2010-50)** – Participated as an expert witness on behalf of OIEC before the Oklahoma Corporation Commission in AEP/PSO's application to recover ice storm O&M expenses through a regulatory asset/rider mechanism to address tax impact and return issues in the proposed rider.

25. **Public Service Company of Colorado, 2011 (Docket No. 10AL-908E) –** Participated as an expert witness on behalf of the Colorado Retail Council ("CRC") before the Colorado Public Utilities Commission providing written and live testimony to address PSCo's proposed Environmental Tariff.

26. **Oklahoma Gas & Electric Company, 2011 (Docket No. 10-067-U)** – Participated as an expert witness on behalf of the Northwest Arkansas Industrial Energy Consumers ("NWIEC")[5] before the Arkansas Public Service Commission in OG&E's general rate case application to provide testimony on various revenue requirement, cost of service and rate design issues.

27. **Oklahoma Gas & Electric Company, 2010 (Cause No. PUD 2010-146)** – Participated as an expert witness on behalf of the OIEC before the OCC in OG&E's application seeking rider recovery of third party SPP transmission costs and SPP administration fees.

28. **Massachusetts Electric Co. & Nantucket Electric Co. d/b/a National Grid, 2010 (Docket No. DPU 10-54)** – Participated as an expert witness providing both written and live testimony before the Massachusetts Department of Public Utilities on behalf of the Associated Industries of Massachusetts ("AIM") to address the Company's proposed participation in the 438MW Cape Wind project in Nantucket Sound

29. **Public Service Company of Oklahoma, 2010 (Cause No. PUD 2010-50)** – Participated as an expert witness on behalf of the OIEC before the OCC in AEP/PSO's general rate case application to provide testimony on various cost-of-service issues and on the utility's overall revenue requirement and rate design proposals.

30. **Texas-New Mexico Power Co., 2010 (Docket 38480)** – Participating as an expert witness on behalf of the Alliance of Texas Municipalities ("ATM") before the Texas PUC in TMNP's general rate case application to address various revenue requirement and rate design issues to establish prospective cost-of-service based rates.

5 NWIEC is an association of industrial manufacturing facilities in northwest Arkansas.

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31. **Southwestern Public Service Co., 2010 (PUCT Docket No. 38147) –** Participating as an expert witness on behalf of the Alliance of Xcel Municipalities ("AXM") in the SPS general rate case application to provide testimony before the Texas Public Utility Commission regarding rate base and operating expense issues and sponsor the AXM Accounting Exhibits.

32. **Oklahoma Gas & Electric Company, 2010 (Cause No. PUD 2010-37)** – Participating as an expert witness on behalf of OIEC before the OCC to address the preapproval and ratemaking treatment of OG&E's 220MW self-build wind project.

33. **Oklahoma Gas & Electric Company, 2010 (Cause No. PUD 2010-29)** – Participated as an expert witness on behalf of the OIEC before the OCC in OG&E's application seeking pre-approval of deployment of smart-grid technology and rider-recovery of the associated costs. Sponsored written testimony to address smart-grid deployment and time-differentiated fuel rates.

34. **Public Service Company of Oklahoma, 2010 (Cause No. PUD 2010-01)** – Participated as an expert witness on behalf of the OIEC before the OCC in the Company's proposed Green Energy Choice Tariff. Sponsored testimony to address the pricing and ratemaking treatment of the Company's proposed wind subscription tariff.

35. **Nevada Power Company, 2010 (Docket No. 10-02009) –** Participated as an expert witness on behalf of the Southern Nevada Hotel Group ("SNHG") before the Nevada PUC to provide testimony in NPC's Internal Resource Plan to address the ratemaking treatment of the proposed ON Line transmission line.

36. **Entergy Texas Inc., 2010 (PUC Docket No. 37744) –** Participating as an expert witness on behalf of the Cities in ETI's general rate case to provide testimony on various cost of service issues and on the utility's overall revenue requirement.

37. **El Paso Electric Company, 2010 (PUC Docket No. 37690)** – Participated as an expert witness on behalf of the City of El Paso in the EPI general rate case to provide testimony on various cost of service issues and on the utility's overall revenue requirement.

38. **Public Service Company of Oklahoma, 2009 (Cause No. 09-196) –** Participated as an expert witness on behalf of the OIEC before the OCC in PSO's application for approval of DSM programs and cost recovery. Sponsored testimony to address program costs, lost revenue recovery, cost allocations and incentives.

39. **Oklahoma Gas and Electric Company, 2009 (Cause No. PUD 09-230 and 09-231) –** Participated as an expert witness on behalf of OIEC before the OCC in OG&E's application to add wind resources from two purchased power contracts. Sponsored written testimony to address the proper ratemaking treatment of the contract costs and the renewable energy certificates.

40. **Oklahoma Gas and Electric Company, 2009 (Cause No. PUD 08-398) –** Participated as an expert witness on behalf of OIEC before the OCC in OG&E's rate case. Provided testimony in both the revenue requirement and rate design phases of the proceedings to establish prospective cost-of-service based rates for the power company.

41. **Nevada Power Company, 2009, (Docket No. 08-12002)** - Participated as an expert witness on behalf of the Southern Nevada Hotel Group before the Nevada PUC. Sponsored written and oral testimony in both the revenue requirement phase and the rate design phase of the proceedings to establish prospective cost-of-service based rates for the power company.

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42. **Public Service Company of Oklahoma, 2009 (Cause No. 09-031) –** Participated as an expert witness on behalf of OIEC before the OCC in PSO's application to add wind resources from two purchased power contracts. Sponsored written testimony to address the proper ratemaking treatment of the contract costs and the renewable energy certificates.

43. **Oklahoma Natural Gas Co., 2009 (Cause No. PUD 08-348) –** Participated as an expert witness on witness on behalf of the OIEC before the OCC in ONG's application to establish a Performance Based Rate tariff. Sponsored both written and oral testimony to address the merits of the utility's proposed PBR.

44. **Rocky Mountain Power, 2009 (Docket No. 08-035-38) –** Participated as an expert witness on behalf of the Division of Public Utilities (Staff) in PacifiCorp's general rate case to provide testimony on various revenue requirement issues.

45. **Texas-New Mexico Power Co., 2008 (Docket 36025)** – Participating as an expert witness on behalf of the Alliance of Texas Municipalities ("ATM") before the Texas PUC in TMNP's general rate case application to address various revenue requirement and rate design issues to establish prospective cost-of-service based rates.

46. **Public Service Company of Oklahoma, 2008 (Cause No. 08-144) –** Participated as an expert witness on behalf of the OIEC before the OCC in PSO's general rate case application to address revenue requirement and rate design issues to establish prospective cost-of-service based rates.

47. **Public Service Company of Oklahoma, 2008 (Cause No. 08-150) –** Participated as an expert witness on behalf of the OIEC before the OCC to address PSO's calculation of its Fuel Clause Adjustment for 2008.

48. **Oklahoma Gas and Electric Company, 2008 (Cause No. PUD 08-059) –** Participated as an expert witness on behalf of the OIEC before the OCC in OG&E's application seeking authorization of its Demand Side Management ("DSM") programs and the establishment of a DSM Rider to recover program costs, lost revenues and utility incentives.

49. **Entergy Gulf States, 2008 (PUC Docket No. 34800, SOAH Docket No. 473-08-0334) –** Participated as an expert witness on behalf of the Cities in EGSI's general rate case to provide testimony on various cost of service issues and on the utility's overall revenue requirement.

50. **Public Service Company of Oklahoma, 2008 (Cause No. 07-465) –** Participated as an expert witness on behalf of the OIEC before the OCC in PSO's application to recover the pre-construction costs of the cancelled Red Rock coal generation facility.

51. **Oklahoma Gas and Electric Company, 2008 (Cause No. 07-447) –** Participating as an expert witness on behalf of the OIEC before the OCC in OG&E's application seeking authorization to recover the pre-construction costs of the cancelled Red Rock coal generation facility using proceeds from sales of excess SO_2 allowances.

52. **Rocky Mountain Power, 2008 (Docket No. 07-035-93) –** Participating as an expert witness on behalf of Division of Public Utilities (Staff) in PacifiCorp's general rate case to provide testimony on various revenue requirement issues.

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53. **Public Service Company of Oklahoma, 2008 (Cause No. PUD 07-449) –** Participated as an expert witness on behalf of the OIEC before the OCC in PSO's application seeking authorization of its Demand Side Management ("DSM") programs and the establishment of a DSM Rider to recover program costs, lost revenues and utility incentives.

54. **Public Service Company of Oklahoma, 2008 (Cause No. PUD 07-397) –** Participated as an expert witness on behalf of OIEC before the OCC in PSO's application seeking authorization to defer storm damage costs in a regulatory asset account and to recover the costs using the proceeds from sales of excess SO_2 allowances.

55. **Oklahoma Gas & Electric Co., 2007 (Cause No. PUD 07-012) –** Participated as an expert witness on behalf of OIEC before the OCC in OG&E's application seeking pre-approval to construct the Red Rock coal plant to address the Company's proposed rider recovery mechanism.

56. **Oklahoma Natural Gas Co., 2007 (Cause No. PUD 07-335) –** Participated as an expert witness on behalf of the OIEC before the OCC in ONG's application proposing alternative cost recovery for the Company's ongoing capital expenditures through the proposed Capital Investment Mechanism Rider ("CIM Rider"). Sponsored testimony to address ONG's proposal.

57. **Public Service Company of Oklahoma, 2007 (Cause No. PUD 06-030) –** Participated as an expert witness on behalf of the OIEC before the OCC in PSO's application seeking a used and useful determination for its planned addition of the Red Rock coal plant to address the Company's use of debt equivalency in the competitive bidding process for new resources.

58. **Public Service Company of Oklahoma, 2006 (Cause No. PUD 06-285) –** Participated as an expert witness on behalf of the OIEC before the OCC in PSO's general rate case application to address various revenue requirement and rate design issues to establish prospective cost-of-service based rates.

59. **Nevada Power Company, 2007, (Docket No. 07-01022)** - Participated as an expert witness on behalf of the MGM MIRAGE before the Nevada PUC in Nevada Power Company's deferred energy docket to determine the level of prudent company expenditures for fuel and purchased power.

60. **Nevada Power Company, 2006, (Docket No. 06-11022)** - Participated as an expert witness on behalf of the MGM MIRAGE properties before the Nevada PUC. Sponsored written and oral testimony in both the revenue requirement phase and the rate design phase of the proceedings to establish prospective cost-of-service based rates for the power company.

61. **Southwestern Public Service Co., 2006 (PUCT Docket No. 37766) –** Participated as an expert witness on behalf of the Alliance of Xcel Municipalities ("AXM") in the SPS general rate case application. Provided testimony before the Texas Public Utility Commission regarding rate base and operating expense issues and sponsored the Accounting Exhibits on behalf of AXM.

62. **Atmos Energy Corp., Mid-Tex Division, 2006 (Texas GUD 9676) –** Participated as an expert witness in the Atmos Mid-Tex general rate case application on behalf of the Atmos Texas Municipalities ("ATM"). Provided written and oral testimony before the Railroad Commission of Texas regarding the revenue requirements of Mid-Tex including various rate base, operating expense, depreciation and tax issues. Sponsored the Accounting Exhibits for ATM.

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63. **Nevada Power Company, 2006 (Docket No. 06-06007) –** Participated as an expert witness on behalf of the MGM MIRAGE in the Sinatra Substation Electric Line Extension and Service Contract case. Provided both written and oral testimony before the Nevada Public Utility Commission to provide the Commission with information as to why the application is consistent with the line extension requirements of Rule 9 and why the cost recovery proposals set forth in the application provide a least cost approach to adding necessary new capacity in the Las Vegas strip area.

64. **Public Service Co. of Oklahoma, 2006 (Cause No. PUD 05-00516) -** Participated as an expert witness on behalf of the OIEC to review PSO's application for a "used and useful" determination of its proposed peaking facility.

65. **Oklahoma Gas and Electric Co., 2006 (Cause No. PUD 06-00041) –** Participated as an expert witness on behalf of the OIEC in OG&E's application to propose an incentive sharing mechanism for SO_2 allowance proceeds.

66. **Chermac Energy Corporation, 2006 (Cause No. PUD 05-00059 and 05-00177) –** Participated as an expert witness on behalf of the OIEC in Chermac's PURPA application. Sponsored written responsive and rebuttal testimony to address various rate design issues arising under the application.

67. **Oklahoma Gas and Electric Co., 2006 (Cause No. PUD 05-00140) –** Participated as an expert witness on behalf of the OIEC in OG&E's 2003 an 2004 Fuel Clause reviews. Sponsored written testimony to address the purchasing practices of the Company, it transactions with affiliates, and the prices paid for natural gas, coal and purchased power.

68. **Nevada Power Company, 2006, (Docket No. 06-01016)** - Participated as an expert witness on behalf of the MGM MIRAGE properties before the Nevada PUC. Sponsored written testimony in NPC's deferred energy docket to determine the level of prudent company expenditures for fuel and purchased power.

69. **Oklahoma Gas and Electric Co., 2005 (Cause No. PUD 05-151) –** Participated as an expert witness on behalf of the OIEC in OG&E's general rate case application. Sponsored both written and oral testimony before the OCC to address various revenue requirement and rate design issues for the purpose of setting prospective cost-of-service based rates.

70. **Oklahoma Natural Gas Co., 2005 (Cause No. PUD 04-610) –** Participated as an expert witness on behalf of the Attorney General of Oklahoma. Sponsored written and oral testimony to address numerous rate base, operating expense and depreciation issues for the purpose of setting prospective cost-of-service based rates.

71. **CenterPoint Energy Arkla, 2004 (Cause No. PUD 04-0187)** – Participating as an expert witness on behalf of the Attorney General of Oklahoma: Sponsored written testimony to provide the OCC with analysis from an accounting and ratemaking perspective of the Co.'s proposed change in depreciation rates from an Average Life Group to an Equal Life Group methodology. Addressed the Co.'s proposed increase in depreciation rates associated with increased negative salvage value calculations.

72. **Public Service Co. of Oklahoma, 2004 (Cause No. PUD 02-0754) –** Participated as an expert witness on behalf of the OIEC. Sponsored written testimony (1) making adjustments to PSO's requested recovery of an ICR programming error, (2) correcting errors in the allocation of trading margins on off-system sales of electricity from AEP East to West and among the AEP West utilities and (3) recommending an annual rather than a quarterly change in the FAC rates.

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73. **PowerSmith Cogeneration Project, 2004 (Cause No. PUD 03-0564) -** Participated as an expert witness on behalf of the OIEC to provide the OCC with direction in setting an avoided cost for the PowerSmith Cogeneration project under PURPA requirements. Provided both written and oral testimony on the provisions of the proposed contract under PURPA:

74. **Electric Utility Rules for Affiliate Transactions, 2004 (Cause No. RM 03-0003)** – Participated as a consultant on behalf of the OIEC to draft comments to assist the OCC in developing rules for affiliate transactions. Assisted in drafting the proposed rules. Successful in having the Lower of Cost or Market rule adopted for affiliate transactions in Oklahoma.

75. **Nevada Power Company, 2003, (Docket No. 03-10001)** - Participated as an expert witness on behalf of the MGM MIRAGE properties before the Nevada PUC. Sponsored written and oral testimony in both the revenue requirement phase and the rate design phase of the proceedings to establish prospective cost-of-service based rates for the power company.

76. **Nevada Power Company, 2003, (Docket No. 03-11019)** - Participated as an expert witness on behalf of the MGM MIRAGE before the Nevada PUC in Nevada Power Company's deferred energy docket to determine the level of prudent company expenditures for fuel and purchased power.

77. **Public Service Company of Oklahoma, 2003 (Cause No. PUD 03-0076) –** Participating as an expert witness on behalf of the OIEC before the OCC in PSO's general rate case application to address various revenue requirement and rate design issues to establish prospective cost-of-service based rates.

78. **Oklahoma Gas & Electric Co., 2003 (Cause No. PUD 03-0226) –** Participated as an expert witness on behalf of the OIEC. Provided both written and oral testimony before the OCC to determine the appropriate level to include in rates for natural gas transportation and storage services acquired from an affiliated company.

79. **Nevada Power Company, 2003 (Docket No. 02-5003-5007)** - Participated as an expert witness on behalf of the MGM Mirage before the Nevada PUC. Sponsored written and oral testimony to calculate the appropriate exit fee in MGM Mirage's 661 Application to leave the system.

80. **McCarthy Family Farms, 2003** – Participated as a consultant to assist McCarthy Family Farms in converting a biomass and biosolids composting process into a renewable energy power producing business in California.

81. **Bice v. Petro Hunt, 2003 (ND, Supreme Court No. 20030306)** - Participated as an expert witness in a class certification proceeding to provide cost-of-service calculations for royalty valuation deductions for natural gas gathering, dehydration, compression, treatment and processing fees in North Dakota.

82. **Nevada Power Company, 2003 (Docket No. 03-11019) -** Participated as a consulting expert on behalf of the MGM Mirage before the Nevada PUC in Nevada Power Company's deferred energy docket to determine the level of prudent company expenditures for fuel and purchased power. Provided written and oral testimony on the reasonableness of the cost allocations to the utility's various customer classes.

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83. **Wind River Reservation, 2003 (Fed. Claims Ct. No. 458-79L, 459-79L)** – Participated as a consulting expert on behalf of the Shoshone and Arapaho Tribes to provide cost-of-service calculations for royalty valuation deductions for gathering, dehydration, treatment and compression of natural gas and the reasonableness of deductions for gas transportation.

84. **Oklahoma Gas & Electric Co., 2002 (Cause No. PUD 01-0455) –** Participated as an expert witness on behalf of the OIEC before the OCC. Sponsored written and oral testimony on numerous revenue requirement issues including rate base, operating expense and rate design issues to establish prospective cost-of-service based rates.

85. **Nevada Power Company, 2002 (Docket No. 02-11021) -** Participated as an expert witness on behalf of the MGM Mirage before the Nevada PUC in Nevada Power Company's deferred energy docket to determine the level of prudent company expenditures for fuel and purchased power and to make recommendations with respect to rate design.

86. **Nevada Power Company, 2002 (Docket No. 01-11029) -** Participated as a consulting expert on behalf of the MGM Mirage before the Nevada PUC in Nevada Power Company's deferred energy docket to determine the level of prudent company expenditures for fuel and purchased power included in the Company's $928 million deferred energy balances.

87. **Nevada Power Company, 2002 (Docket No. 01-10001)** - Participated as an expert witness on behalf of the MGM Mirage before the Nevada PUC. Sponsored written and oral testimony in both the revenue requirement phase and the rate design phase of the proceedings to establish prospective cost-of-service based rates for the power company.

88. **Chesapeake v. Kinder Morgan, 2001 (CIV-00-397L) -** Participated as an expert witness on behalf of Chesapeake Energy in a gas gathering dispute. Sponsored testimony to calculate and support a reasonable rate on the gas gathering system. Performed necessary calculations to determine appropriate levels of operating expense, depreciation and cost of capital to include in a reasonable gathering charge and developed an appropriate rate design to recover these costs.

89. **Southern Union Gas Company, 2001** - Participated as a consultant to the City of El Paso in its review of SUG's gas purchasing practices, gas storage position, and potential use of financial hedging instruments and ratemaking incentives to devise strategies to help shelter customers from the risk of high commodity price spikes during the winter months.

90. **Nevada Power Company, 2001 -** Participated as an expert witness on behalf of the MGM-Mirage, Park Place and Mandalay Bay Group before the Nevada Public Utility Commission to review NPC's Comprehensive Energy Plan (CEP) for the State of Nevada and make recommendations regarding the appropriate level of additional costs to include in rates for the Company's prospective power costs associated with natural gas and gas transportation, coal and coal transportation and purchased power.

91. **Bridenstine v. Kaiser-Francis Oil Co. et al., 2001 (CJ-95-54)** - Participated as an expert witness on behalf of royalty owner plaintiffs in a valuation dispute regarding gathering, dehydration, metering, compression, and marketing costs. Provided cost-of-service calculations to determine the reasonableness of the gathering rate charged to the royalty interest. Also provided calculations as to the average price available in the field based upon a study of royalty payments received on other wells in the area.

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92. **Klatt v. Hunt et al., 2000 (ND)** - Participated as an expert witness and filed report in United States District Court for the District of North Dakota in a natural gas gathering contract dispute to calculate charges and allocations for processing, sour gas compression, treatment, overhead, depreciation expense, use of residue gas, purchase price allocations, and risk capital.

93. **Oklahoma Gas and Electric Co., 2000 (Cause No. PUD 00-0020)** - Participated as an expert witness on behalf of the OIEC before the OCC. Sponsored testimony on OG&E's proposed Generation Efficiency Performance Rider (GEPR). Provided a list of criteria with which to measure a utility's proposal for alternative ratemaking. Recommended modifications to the Company's proposed GEPR to bring it within the boundaries of an acceptable alternative ratemaking formula.

94. **Oklahoma Gas and Electric Co., 1999 -** Participated as an expert witness on behalf of the OIEC before the OCC. Sponsored testimony on OG&E's proposed Performance Based Ratemaking (PBR) proposal including analysis of the Company's regulated return on equity, fluctuations in the capital investment and operating expense accounts of the Company and the impact that various rate base, operating expense and cost of capital adjustments would have on the Company's proposal.

95. **Nevada Power Company, 1999 (Docket No. 99-7035) -** Participated as an expert witness on behalf of the Mirage, Park Place and Mandalay Bay Group before the Nevada PUC. Sponsored written and oral testimony addressing the appropriate ratemaking treatment of the Company's deferred energy balances, prospective power costs for natural gas, coal and purchased power and deferred capacity payments for purchased power.

96. **Nevada Power Company, 1999 (Docket No. 99-4005) -** Participated as an expert witness on behalf of the Mirage, Park Place and Mandalay Bay Group before the Nevada PUC. Sponsored written and oral testimony to unbundle the utility services of the NPC and to establish the appropriate cost-of-service allocations and rate design for the utility in Nevada's new competitive electric utility industry.

97. **Nevada Power Company, 1999 (Docket No. 99-4005) -** Participated as an expert witness on behalf of the Mirage, Park Place and Mandalay Bay Group before the Nevada PUC. Sponsored written and oral testimony to establish the cost-of-service revenue requirement of the Company.

98. **Nevada Power/Sierra Pacific Merger, 1998 (Docket No. 98-7023) -** Participated as an expert witness on behalf of the Mirage and MGM Grand before the Nevada PUC. Sponsored written and oral testimony to establish (1) appropriate conditions on the merger (2) the proper sequence of regulatory events to unbundle utility services and deregulate the electric utility industry in Nevada (3) the proper accounting treatment of the acquisition premium and the gain on divestiture of generation assets. The recommendations regarding conditions on the merger, the sequence of regulatory events to unbundle and deregulate, and the accounting treatment of the acquisition premium were specifically adopted in the Commission's final order.

99. **Oklahoma Natural Gas Company, 1998 (Cause No. PUD 98-0177) -** Participated as an expert witness in ONG's unbundling proceedings before the OCC. Sponsored written and oral testimony on behalf of Transok, LLC to establish the cost of ONG's unbundled upstream gas services. Substantially all of the cost-of-service recommendations to unbundle ONG's gas services were adopted in the Commission's interim order.

100. **Public Service Company of Oklahoma, 1997 (Cause No. PUD 96-0214) -** Audited both rate base investment and operating revenue and expense to determine the Company's revenue requirement and cost-of-service. Sponsored written testimony before the OCC on behalf of the OIEC.

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101. **Oklahoma Natural Gas /Western Resources Merger, 1997 (Cause No. PUD 97-0106) -** Sponsored testimony on behalf of the OIEC regarding the appropriate accounting treatment of acquisition premiums resulting from the purchase of regulated assets.

102. **Oklahoma Gas and Electric Co., 1996 (Cause No. PUD 96-0116) -** Audited both rate base investment and operating income. Sponsored testimony on behalf of the OIEC for the purpose of determining the Company's revenue requirement and cost-of-service allocations.

103. **Oklahoma Corporation Commission, 1996 -** Provided technical assistance to Commissioner Anthony's office in analyzing gas contracts and related legal proceedings involving ONG and certain of its gas supply contracts. Assignment included comparison of pricing terms of subject gas contracts to portfolio of gas contracts and other data obtained through annual fuel audits analyzing ONG's gas purchasing practices.

104. **Tenkiller Water Company, 1996 -** Provided technical assistance to the Attorney General of Oklahoma in his review of the Company's regulated cost-of-service for the purpose of setting prospective utility rates.

105. **Arkansas Oklahoma Gas Company, 1995 (Cause No. PUD 95-0134) -** Sponsored written and oral testimony before the OCC on behalf of the Attorney General of Oklahoma regarding the price of natural gas on AOG's system and the impact of AOG's proposed cost of gas allocations and gas transportation rates and tariffs on AOG's various customer classes.

106. **Enogex, Inc., 1995 (FERC 95-10-000) -** Analyzed Enogex's application before the FERC to increase gas transportation rates for the Oklahoma Independent Petroleum Association and made recommendations regarding revenue requirement, cost-of-service and rate design on behalf of independent producers and shippers.

107. **Oklahoma Natural Gas Company, 1995 (Cause No. PUD 94-0477) -** Analyzed a portfolio of ONG's gas purchase contracts in the Company's Payment-In-Kind (PIC) gas purchase program and made recommendations to the OCC Staff on behalf of Terra Nitrogen, Inc. regarding the inappropriate profits made by ONG on the sale of the gas commodity through the PIC program pricing formula. Also analyzed the price of gas on ONG's system, ONG's cost-of-service based rates, and certain class cross-subsidizations in ONG's existing rate design.

108. **Arkansas Louisiana Gas Company, 1994 (Cause No. PUD 94-0354) -** Planned and supervised the rate case audit for the OCC Staff and reviewed the workpapers and testimony of the other auditors on the case. Sponsored cost-of-service testimony on cash working capital and developed policy recommendations on post test year adjustments.

109. **Empire District Electric Company, 1994 (Cause No. PUD 94-0343) -** Planned and supervised the rate case audit for the OCC Staff and reviewed the workpapers and testimony of other auditors. Sponsored cost-of-service testimony on rate base investment areas including cash working capital.

110. **Oklahoma Natural Gas Company, 1992 through 1993 (Cause No. PUD 92-1190) -** Planned and supervised the rate case audit of ONG for the OCC Staff. Reviewed all workpapers and testimony of the other auditors on the case. Sponsored written and oral testimony on numerous cost-of-service adjustments. Analyzed ONG's gas supply contracts under the Company's PIC program.

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111. Oklahoma Gas and Electric Company, 1991 through 1992 (Cause No. PUD 91-1055) - Audited the rate base, operating revenue and operating expense accounts of OG&E on behalf of the OCC Staff. Sponsored written and oral testimony on numerous revenue requirement adjustments to establish the appropriate level of costs to include for the purpose of setting prospective rates.

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GARRETT GROUP
INCENTIVE COMPENSATION SURVEY
Of the 24 WESTERN STATES
2007, 2009, 2011

States that follow the Financial-Performance rule

Arizona The commission deals with incentive compensation plans on a case by case basis. It first compares overall compensation to the state norm, then asks if the costs are prudent and reasonable. The commission leans toward disallowing programs which benefit only the shareholder even if total compensation is comparable to the state norm. Staff's position is that unless a plan is tied to performance issues it is unnecessary for the provision of service and that shareholders should pay for plans tied to financial measures. In practice, the costs of annual incentive plans are often shared 50/50 between ratepayers and shareholders.[1]

Arkansas Excludes 100% of the long-term, equity-based plans.[2] Short-term incentive plans are evaluated to determine if they are based on financial or operational measures. Operational-based plans are allowed. 50% of plans containing financial measures are disallowed. Any plans based solely on the discretion of the company are seen as having no direct benefit to ratepayers and are disallowed 100%. Settlements in recent cases have upheld this treatment.[3]

California Incentive funding is an issue that is typically litigated. In CPUC Decision 00-02-046, the commission established that utilities could recover 50% of the regular employee's incentive compensation costs in rates. In California's latest litigated rate case, the commission decided that Edison's non-executive plans and 50% of the short-term executive plans would be funded in rates and that 100% of the executive long-term stock plans would be disallowed.[4]

[1] See *e.g.*, APS 2008 rate case, Decision 70360, Southwest Gas 2008 rate case, Decision 70665 and UNS Gas 2008 rate case, Decision 70011.
[2] In this summary of the incentive compensation survey, the treatment of executive incentives in each state is underlined, and will be discussed in the following section of the testimony.
[3] Entergy Arkansas, 06-101-U, Order No. 10.
[4] Southern California Edison (Application No. 07-11-011; Decision No. 09-03-025).

Colorado Regular employee programs are judged based on ratepayer verses stockholder benefit ratio. Plans with metrics for goals benefiting ratepayers but dependent on an earnings-per-share trigger are considered to benefit shareholders and opposed by staff. Staff's approach is set forth most recently, in 10AL-963G by staff witness Kahl. The settlement in that case removed the dollar amount opposed by Kahl. All executive incentives are excluded from rates and typically no longer sought in company filings.

Hawaii Hawaii does not allow incentive compensation to be included in rates. In Docket No. 6531 the commission agreed that bonus awards tied to company income and earnings benefit stockholders, not ratepayers. The commission further states, "...we believe that a utility employee, especially at the executive level, should perform at an optimum level without additional compensation. Ratepayers should not be burdened with additional costs for expected levels of service."[5]

Idaho The commission's policy for evaluating incentive compensation plans involves determining who benefits, the customer or the company. This treatment has been refined in the recent Idaho Power rate case for plans which benefit the customer but require a financial trigger to be paid. For these plans the commission reduced the percentage allowed in rates. The commission also now does not include any executive compensation in rates.[6]

Kansas Plans based solely on financial goals are not allowed. For executive incentive programs, the Commission also disallows 100% of plans based on financial measures and 50% for plans using a balance of financial and operational measures. The Commission has allowed in rates non-executive annual incentive programs that have no focus on profitability or earning.[7]

[5] Hawaii's policy is set forth in Docket No. 6531 in the October 17, 1991 Order No. 11317. Prior Dockets in which the commission disallowed incentive compensation include No. 3216, No. 4215, No. 4588 and No. 5114.

[6] The Commission's focus on customer benefit is reflected in the direct testimony of Staff witness Leckie, and in the final order for IPC General Rate Case IPC-E-08-10. For earlier examples of the basic policy, see Idaho Power Company Rate Case IPC-E-05-28, Corrected Motion for Approval of Stipulation 3/1/06, 6e, p. 4; Idaho Power Company IPC-05-28, Order No. 30035, p. 4/10.

[7] In the litigated 2010 KCP&L rate case (10-KCPE-415-RTS) the Commission also stated that relying on peer group statistics "can result in a continuing upward spiral [instead] the Commission must examine the elements of incentive packages, and the behavior they incent." The Commission held that a focus on profitability or earning might incent employee behavior "detrimental to customers."

Louisiana Traditionally incentive compensation for upper level management and officers is excluded, while costs for lower level managers and employees are allowed. The criteria used to evaluate plan design consider whether the goals of each plan directly benefit ratepayers or shareholders. Stock based compensation plans at all levels are excluded.

Minnesota Minnesota distinguishes between incentive plans tied to financial triggers (such as a threshold ROE), and plans tied to criteria benefitting the ratepayer. Plans based on goals that benefit ratepayers are allowed in rates, but their costs are capped at 25% of base salaries.[8] The portions of these plans that are allowed into rates are tracked and must be returned to ratepayers if they are not paid to employees. Executive plans are largely not allowed.[9]

Missouri Missouri's treatment disallows incentives tied to goals benefitting primarily the stockholders (*e.g.,* tied to earnings per share) while allowing plans with customer-specific goals (*e.g.,* safety). Plans must also be reasonable. The Commission also allows only the amounts actually paid, not those accrued. The same criteria are used for executive plans and few are allowed.[10]

Nevada The commission excludes 100% of the long-term plans and all short-term plan costs directly related to financial performance.[11]

New Mexico The commission does not favor incentive compensation plans that are tied to financial goals and tends to allow in rates those based on operational goals. This standard is applied to all levels of utility employees and tends to eliminate the greater portion of executive plans.[12]

[8] This general policy is demonstrated in recent orders in the Minnesota Power and Ottertail rate cases: E002/GR-09-1151 and E002/GR-10-239 respectively.

[9] Minnesota's general policy is demonstrated in recent orders in the Minnesota Power and Ottertail rate cases: E002/GR-09-1151 and E002/GR-10-239 respectively. See also Minnesota Power General Rate Case E002/GR/05/1428.

[10] See *e.g.*, in the latest Missouri American rate case (WR-2010-0131), not only were plans based on financial goals disallowed, but incentive payments based on customer satisfaction were disallowed due to the unreasonably small sample size used to establish a positive rating (a phone survey of 927 of roughly 450,000 customers). The commission also removed incentive payments tied to lobbying and charitable activity. In the most recent case processed, the Ameren UE rate case, the company did not seek even short-term incentive compensation tied to earnings, providing further indication that staff's practice of disallowing financial performance based incentives is accepted by the companies. All incentive compensation adjustments were made not only to expense charges, but to construction charges as well. *See also* recent Kansas City Power and Light and Empire Electric District orders on the commission's website.

[11] See *e.g.*, PUCN's final order in Docket 11-06006.

[12] See Docket 07-00077-UT.

N. Dakota Historically, North Dakota has followed the general policy that the portion of incentive compensation that relates to shareholder earnings is disallowed and the rest is included. However, in one recent case, the commission chose to determine if overall compensation was reasonable as compared to the market.[13] Executive incentive compensation is not allowed in rates, and is typically not sought by the company.

Oklahoma The commission excludes incentive payments tied to financial performance. From a practical perspective this means that all executive stock plans are excluded and some portion of the annual cash plan for all employees. Since the commission has not been able to determine in recent cases the precise portion of the annual plans tied to financial measures, the commission has excluded 50% of the annual plans. 100% of the executive stock plans are excluded.[14]

Oregon The commission's general policy is to evaluate plans based on whether they benefit the customers or the company. Customer-based plans involving reliability, response speed, etc. are called "merit" (operational) plans. Company-based plans which track increases to the bottom line, ROE, etc. are called "performance" (financial) plans. 50% of the cost of merit plans is disallowed and 75% of the performance plans is disallowed. 100% of officer bonuses are disallowed.[15]

S. Dakota The commission's general policy is to disallow the portion of incentive plans that are based on the company's financial performance.[16] Current treatment also includes disallowing both executive and non-executive management incentive compensation. There are no incentive compensation plans for union employees. Several utilities have whole incentive programs that hinge on whether or not the company earns a certain return. These financial prerequisites cause the whole plans to be excluded from rates.

[13] Other than Xcel, the utilities in North Dakota (Otter Tail and MDU) are highly diversified now (with mostly unregulated operations, *e.g.* MDU 90%). This allows utility executives to draw on the unregulated components for their compensation.

[14] See *e.g.*, AEP-PSO Cause No. PUD 06-285; OG&E Cause No. PUD 05-151; and ONG Cause No. PUD 04-610.

[15] A recent order reflecting this policy can be found in Docket UE 197, Order No. 09-020.

[16] In Docket No. EL 08-030 the settlement excluded bonuses related to "stockholder-benefitting financial goals." The settlement in Xcel rate case Docket No. EL09-009 removed payments based on financial performance indicators. In the settlement agreement signed July 7, 2010 in the Black Hills Power rate case Docket No. EL09-018 the *Staff Memorandum* states, "The settlement removes financial based incentive payments that were included in the capitalized labor costs for plant. Shareholders are the overwhelming beneficiaries of incentive plans that promote the financial performance of the Company and therefore should be responsible for the cost of such compensation."

Texas The general rule is that incentive payments designed to improve the financial performance of the utility are excluded. For example, in PUC Docket No. 28840,[17] the commission disallowed sixty-six percent (66%) of AEP-Texas Central's test year incentive payments in the amount of $4.2 million. This was the portion of the utility's incentive payments that were based on financial performance measures.[18] Long-term executive incentive pay is routinely disallowed.[19]

Utah The commission's general policy is to allow in rates the parts of a plan that are tied to ratepayer benefit and disallow the parts tied to financial goals. Equity-based incentive compensation is excluded from rates.[20]

Washington Incentive plans are evaluated on a case by case basis. Incentives tied to operational efficiency or other measures which benefit ratepayers are allowed in rates and incentives based on return on earnings or other measures that benefit the shareholders are disallowed.[21]

Wyoming Employee incentive compensation plans are evaluated on a case by case basis, distinguishing between employee programs that benefit the ratepayer or the stockholders and requiring the benefitting party to pay. Executive incentive compensation plans are all excluded from rates.

States were Incentive Compensation has not been and Issue

Alaska Incentive compensation is not an issue in rate cases in Alaska. There is no relevant regulation or policy.

Iowa Incentive compensation is not typically an issue because few rate cases are litigated in this jurisdiction. Mid-American has an incentive compensation plan but hasn't filed a rate case in many years. For the state's other utilities, it has been a long time since they have filed a rate case or had a rate increase. The standing treatment is to consider incentive compensation plans on a case-by-case basis and to evaluate whether they are reasonably and prudently incurred. Both of the investor owned utilities in Iowa are under rate freezes until 2013 and 2014.

[17] *Application of AEP Texas Central Company for Authority to Change Rates*, Docket No. 28840; SOAH Docket No. 473-04-1033, Final Order (August 15, 2005).
[18] See ALJ's Proposal for Decision at page 113 in PUC Docket No. 28840, SOAH Docket No. 473-04-1033, issued July 1, 2004. The PFD with respect to the treatment of incentive compensation was adopted by the Commission in its Final Order.
[19] See Final Order in Docket No. 39896 where even rate case costs associated with asking for long-term financial-based incentives was disallowed.
[20] The recent final order in Docket 09-035-23 follows this general policy as does the order in Docket 07-35-93. *See also* Missouri Corp. Rate Case Docket 97-035-01, pp. 10-12; US West Communications Rate Case Docket 95-049-05.
[21] See the Order in Pacific Power and Light Docket 061546.

Montana Montana has no specific treatment directive and considers the issue on a case by case basis. In a recent NorthWestern Energy rate case, as part of a stipulation agreement, the company took a portion of its incentive compensation out of rates, but reserved the right to propose that it be included in a later filing.

Before the

Florida Public Service Commission

Docket Numbers: 130140-EI, 130151-EI, 130092-EI

GULF POWER COMPANY

REVENUE REQUIREMENT EXHIBIT

OF

CITIZENS OF THE STATE OF FLORIDA

DOCKET NOS. 130140-EI, 130151-EI, 130092-EI

October 16, 2013

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130140-EI EXHIBIT 30
PARTY Office of Public Counsel (OPC) Direct
DESCRIPTION Mark E. Garrett (MEG-3)
DATE

Gulf Power Company
Index to Revenue Requirement Exhibits
Projected Test Year Ended December 31, 2014

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Gulf Power Company
Jurisdictional Revenue Requirement
Projected Test Year Ended December 31, 2014
($000)

(1) Line No.	(2) Description	(3) Company's Jurisdictional Proposed Rate Increase	(4) OPC Jurisdictional Adjustments	(5) Ref.	(6) OPC Jurisdictional Proposed Rate Increase
1	Jurisdictional Adjusted Rate Base	$ 1,883,901	$ (37,199)	B-1	$ 1,846,702
2	Required Rate of Return	6.4700%	-0.9500%	D-1	5.520%
3	Jurisdictional Income Requirement (Line 1 x Line 2)	$ 121,888	$ (19,950)		$ 101,938
4	Jurisdictional Adjusted Net Operating Income	76,359	26,806	C-1	103,165
5	Income Deficiency (Sufficiency) (Line 3 - Line 4)	$ 45,529	$ (46,756)		$ (1,227)
6	Earned Rate of Return (Line 4 / Line 1)	4.05%			5.59%
7	Net Operating Income Multiplier	1.633971	0.000211	A-1	1.633760
8	**Base Rate Revenue Increase (Decrease)**	**$ 74,393**	**$ (76,398)**		**$ (2,005)**

Gulf Power Company
Net Operating Income Multiplier
Projected Test Year Ended December 31, 2014
($000)

(1)	(2)	(3)	(4)	(5)
Line No.	Description	Ref.	Company Percentage	OPC Percentage
1	Revenue Requirement		100%	100%
2	Regulatory Assessment Rate		0.0720%	0.0720%
3	Uncollectible Expense Factor	C-4	0.2934%	0.2801%
4	Net Before Income Taxes		99.635%	99.648%
5	State Income Tax Rate (Effective)		5.500%	5.500%
6	State Income Tax		5.4799%	5.4806%
7	Net Before Federal Income Taxes		94.155%	94.167%
8	Federal Income Tax Rate (Effective)		35.000%	35.000%
9	Federal Income Tax		32.9543%	32.9585%
10	Revenue Expansion Factor		61.2007%	61.2085%
11	Net Operating Income Multiplier		1.633968	1.633760
			To Sch A	To Sch A

Gulf Power Company
OPC Adjusted Rate Base
Projected Test Year Ended December 31, 2014
($000)

(1) Line No.	(2) Description	(3) Company's Jurisdictional Rate Base	(4) OPC Jurisdictional Rate Base Adjustments	(5) OPC Jurisdictional Adjusted Rate Base
1	**Plant In Service:**			
2	Plant in Service	$ 2,944,168	$ (2,375)	$ 2,941,793
3	Less: Accumulated Depreciation	(1,243,319)		(1,243,319)
4	Net Plant	$ 1,700,849	$ (2,375)	$ 1,698,474
5	**Other Rate Base Investment:**			
6	Plant Held for Future Use	5,276	-	5,276
7	Construction Work In Progress	26,656	-	26,656
8	Working Capital Allowance	151,120	(34,824)	116,296
9	**Total Rate Base**	$ 1,883,901	$ (37,199)	$ 1,846,702

Gulf Power Company
OPC Rate Base Adjustments
Projected Test Year Ended December 31, 2014
($000)

(1) Line No.	(2) Description	(3) Witness	(4) Ref No.	(5) Total Adjustments to Rate Base	(6) Jurisdictional Allocation Factor	(7) OPC Adjusted Rate Base
1	**Plant in Service Adjustments**					
2	To Remove Incentive Comp from Rate Base	Garrett	B-3	$ (2,420)	0.9814230	$ (2,375)
3	Subtotal			$ (2,420)		$ (2,375)
4	**Working Capital Adjustments**					
5	To Reduce Working Capital	Garrett	B-4	$ (35,372)	0.9845096	$ (34,824)
6	Subtotal			$ (35,372)		$ (34,824)
7	Total			$ (37,792)		$ (37,199)

Gulf Power Company
Rate Base Adjustment for Short Term Incentives
Projected Test Year Ended December 31, 2014
($000)

(1) Line No.	(2) Description	(3) Ref.	(4) Portion Capitalized	(5) Rate Base
7	**Performance Pay Program**	OPC ROG 80		
8	**Capital Items**			
9	Direct			$ 3,261
10	Allocated			828
11	Excluded by GPC			-
12	Subtotal			$ 4,089
13	Financial Portion of Perfomance Pay Program		52.0%	$ (2,126)
14	One Half of Customer Satisfaction Incentives		7.2%	(294)
15	Adjustment to Capitalized Incentives			$ (2,420)

Gulf Power Company
Rate Base Adjustment for Storm Damage Reserve
Projected Test Year Ended December 31, 2014
($000)

(1) Line No.	(2) Description	(3) Ref.	(4) Amount
1	Storm Damage Reserve at 12/31/2013	OPC ROG 162	$ 35,372
2	Adjustment to Include the Storm Damage Reserve in Working Capital		**$ (35,372)**

Gulf Power Company
Adjusted Operating Income Statement
Projected Test Year Ended December 31, 2014
($000)

(1) Line No.	(2) Description	(3) Ref.	(4) Company Jurisdictional Net Operating Statement	(5) OPC Jurisdictional Adjustments	(6) OPC Jurisdictional Adjusted Income Statement
1	**Operating Revenues:**				
2	Sales of Electricity		$ 505,620	$ 1,243	506,863
3	Other Operating Revenues		23,031	-	23,031
4	Total Operating Revenues		$ 528,651	$ 1,243	$ 529,894
5	**Operating Expenses:**				
6	Operation & Maintenance		290,199	$ (28,135)	262,064
7	Depreciation & Amortization		104,505	(13,878)	90,627
8	Amortization of ITC		(878)	-	(878)
9	Taxes Other Than Income		31,917	(814)	31,103
10	Income Taxes Federal & State		12,985	17,264	30,249
11	Net Federal Deferred Income Tax		7,959	-	7,959
12	Net State Deferred Income Tax		5,605	-	5,605
			-		-
13	**Total Operating Expenses**		$ 452,292	$ (25,563)	$ 426,729
14	**Operating Income**		$ 76,359	$ 26,806	$ 103,165

Gulf Power Company
Net Operating Income Adjustments
Projected Test Year Ended December 31, 2014
($000)

(1) Line No.	(2) Description	(3) Witness	(4) Ref. No.	(5) Total Company Adjustment to Net Operating Income	(6) Jurisdictional Allocation Factor	(7) Jurisdictional Adjustment to Net Operating Income
1	**Operating Revenues Adjustments**					
2	To Adjust Revenues	Garrett	C- 11	1,243	1.0000000	$ 1,243
3	**Operations & Maintenance Expense**					
4	To Adjust Short Term Incentive Expense	Garrett	C-3	(8,579)	0.9806803	(8,413)
5	To Adjust Long Term Incentive Expense	Garrett	C-3	(3,160)	0.9792787	(3,095)
6	To Adjust SERP Expense	Garrett	C- 4	(2,220)	0.9792787	(2,174)
7	To Adjust Payroll expense	Garrett	C- 5	(2,248)	0.9806803	(2,205)
8	To Adjust Medical Expense	Garrett	C-6	(387)	0.9806803	(380)
9	To Adjust D&O Expense	Garrett	C- 7	(48)	0.9792787	(47)
10	To Adjust Storm Damages Expense	Garrett	C- 8	(9,000)	0.9845096	(8,861)
11	To Adjust Corporate Aircraft Expense	Garrett	C- 9	(2,244)	0.9792787	(2,198)
12	To Uncollectible Expense	Garrett	C-10	(146)	0.9830180	$ (144)
13	To Adjust Transmission Expenses	Norwood	C-12	(637)	0.9705818	(618)
14	Reserved			-	0.9806803	-
15	Subtotal			$ (28,669)		$ (28,135)
16	**Depreciation & Amortization**					
17	Depreciation Expense	Pous	C - 13	(14,133)	0.9819407	(13,878)
18	Subtotal			$ (14,133)		$ (13,878)
19	**Taxes Other than Income**					
20	To Adjust Payroll Tax Expense	Garrett	C-3, C- 5	(828)	0.9830180	(814)
21	Subtotal			$ (828)		$ (814)
22	**Income Taxes**					
23	Parent Debt Adjustment			$ -	0.9813165	$ -
24	Impact of O&M and Other Tax Adj. on FIT		C - 14	14,691	1.0000000	$ 14,691
25	Impact of O&M and Other Tax Adj. on SIT		C - 14	2,309	1.0000000	$ 2,309
26	Interest Synchronization Adjustment		C-15	$ 264	1.0000000	$ 264
27	Total Income Federal & State Income Taxes			$ 17,264		$ 17,264
28	Total Operating Income Adjustments			$ 27,609		$ 26,806
29	NOI before Income Tax Adjustments					$ 44,070

Gulf Power Company
Short Term and Long Term Incentive Adjustments
Projected Test Year Ended December 31, 2014
($000)

(1) Line No.	(2) Description	(3) Ref.	(4) Amount
	Short-Term Incentive Expense Adjustment		
1	Total Short-Term Incentive Expense	OPC-ROG 80	$ 14,493
2	Financial Related Short-Term Incentives	OPC-ROG 80, (h) & (i)	-52%
3	Adjustment to Exclude Financial Related Short-Term Incentives		$ (7,536)
4	Adjustment to Exclude 50% of Customer Satisfaction Incentives	OPC-ROG 80 (k)	(1,043)
5	Total Adjustment to Short-Term Incentive Expense		$ (8,579)
6	Payroll Tax Rate		7.65%
7	Adjustment to Payroll Taxes for Short-Term Incentives		$ (656)
	Long-Term Incentive Expense Adjustment		
8	Total Long-Term Incentive Expense	OPC-ROG 81 and 82, (a), (b), and (e)	$ 3,160
9	Financial Related Portion to Exclude		-100%
10	Adjustment to Exclude Financial Related Short-Term Incentives		$ (3,160)

Gulf Power Company
Supplemental Executive Retirement Plan Adjustment
Test Year Ended 12-31-10
($000)

(1) Line No.	(2) Description	(3) Ref.	(4) Total
1	Supplemental Executive Retirement Plan Costs	OPC-ROG-7	$ 2,220
2	Expense Percentage		100.00%
3	Total Company SERP in Cost of Service		$ 2,220
4	Adjustment to Remove SERP Expense		$ (2,220)

Gulf Power Company
Payroll Expense and Payroll Tax Adjustments
Projected Test Year Ended December 31, 2014
($000)

(1) Line No.	(2) Description	(3) Ref.	(4)	(5) Amount
1	Company's Payroll Expense, 2012	OPC-POD 1-1		$ 81,371
2	Manufacturing Sector Productivity 2007-2012	Productivity and Labor Costs, BLS 9/2/2013		1.7%
3	OPC Productivity Adjustment 2012 - 2013			$ (1,383)
4	Adjusted Company's Payroll Expense, 2013	OPC-POD 1-1 + Line 3	$ 83,735	
5	Manufacturing Sector Productivity 2007-2012	Productivity and Labor Costs, BLS 9/2/2013	1.7%	
6	OPC Productivity Adjustment 2013 - 2014			(1,423)
7	OPC Total Productity Adjustments	Line 3 + Line 6		$ (2,806)
8	Less Company's Hiring Lag Adjustment	OPC-POD 1, C-3 Backup		(558)
9	OPC Net Productivity Adjustment	Line 7 - Line 8		$ (2,248)
10	Payroll Tax Rate			7.65%
11	OPC Payroll Tax Adjustment	Line 9 x Line 10		$ (172)

Gulf Power Company
Employee Medical Expense Adjustment
Projected Test Year Ended December 31, 2014
($000)

(1) Line No.	(2) Description	(3)	(4) Ref.	(5) Amount
1	2012 Medical Expense		OPC-ROG 10	$ 8,728
2	Employee Increase Factor			1.0475
3	Medical Cost Increase, 7% for 2 years		TW: 2013 Employer Survey on Purchasing Value in Health Care	1.1449
4	OPC Employee Medical Cost			$ 10,467
5	Less Company Proforma Employee Medical Cost		OPC-ROG 10	10,854
6	OPC Adjustment to Employee Medical Cost			$ (387)

Gulf Power Company
Directors and Officers' Liability Insurance Expense Adjustment
Projected Test Year Ended December 31, 2014
($000)

(1) Line No.	(2) Description	(3) Ref.	(4) Amount
1	Total Director and Officer Liability Insurance	Erickson, p. 11	$ 95
2	Portion to Exclude		50%
3	Adjustment to Director and Officer Liability Insurance		$ (48)

Gulf Power Company
Storm Damage Accrual Adjustment
Projected Test Year Ended December 31, 2014
($000)

(1) Line No.	(2) Description	(3) Ref.	(4) Amount
1	OPC Recommended Storm Damage Reserve Accrual		$ -
2	Test Year Storm Damage Reserve Accrual	Erickson, p. 6	9,000
3	OPC Adjustment to Storm Damage Reserve Accrual		$ (9,000)

Gulf Power Company
Corporate Aircraft Cost Allocation Adjustment
Projected Test Year Ended December 31, 2014
($000)

(1) Line No.	(2) Description	(3) Ref.	(4) Amount
1	OPC Recommended Corporate Aircraft Cost		$ -
2	Company's Requested Corporate Aircraft Cost	OPC-ROG 43	2,244
3	OPC Adjustment to Corporate Aircraft Expenses		$ (2,244)

Gulf Power Company
Uncollectible Accounts Expense Adjustment
Projected Test Year Ended December 31, 2014
($000)

(1) Line No.	(2) Description	(3) Ref.	(4) Net Write-Offs	(5) Gross Revenues	(6) Uncollectible Factor
1	2010	GPC C-11	$ 3,806	$ 1,295,892	0.2937%
2	2011	GPC C-11	$ 3,384	$ 1,233,068	0.2744%
3	2012	GPC C-11	$ 3,084	$ 1,133,224	0.2721%
4	3-Year Average Uncollectible Factor				0.2801%
5	2014 Gross Revenues, Per Company				$ 1,307,803 (1)
6	OPC Recommended Uncollectible Amount				$ 3,663
7	Uncollectible Amount per Company	GPC C-4			$ 3,809
8	OPC Reduction to Uncollectible Accounts				$ (146)

(1) Inadvertently, a 2012 value was used. The amount should be $1,293,402, based on GPC C-11. The error favors the Company. However, correcting the error would have only a de minimis effect on the adjustment shown. For that reason, and due to the timing of the discovery of the error, the correction (which would impact several schedules) was not made.

Gulf Power Company
Revenue Annualization Adjustment
Projected Test Year Ended December 31, 2014
($000)

(1) Line No.	(2) Description	(3) Ref.	(4) Revenue Amount
1	OPC Adjusted Residential Electric Revenue Based on Annualized Customers		$ 297,720
2	Gulf Power Company Adjusted Residential Electric Revenue	GPC E-13c, p 1	$ 296,477
3	Adjusted Amount		$ 1,243

Gulf Power Company
Transmission Expense Adjustment
Projected Test Year Ended December 31, 2014
($000)

(1) Line No.	(2) Description	(3) Ref.	(4) Amount
1	OPC Adjustment to Transmission Expense	Norwood	$ (637)

Gulf Power Company
Depreciation Expense Adjustment
Projected Test Year Ended December 31, 2014
($000)

(1) Line No.	(2) Description	(3) Ref.	(4) Amount
1	OPC Total Adjustment to Depreciation Expense		$ (19,986)
2	Less: OPC Adjustment to Depreciation Expense in Cost Recovery Clauses	Pous	(5,853)
3	OPC Adjustment to Depreciation Expense in Base Rates		$ (14,133)

Gulf Power Company
Current Income Tax Expense Adjustment
Projected Test Year Ended December 31, 2014
($000)

(1) Line No.	(2) Description	(3) Ref.	(4) Amount
1	Jurisdictional Operating Income Adj. before Income Taxes		$ 44,070
2	Composite Income Tax Rate		38.575%
3	Adjustment to Income Tax Expense		$ 17,000
4	Federal		$ 14,691
5	State		2,309
6	Total Federal & State		$ 17,000

Gulf Power Company
Interest Synchronization Adjustment
Projected Test Year Ended December 31, 2014
($000)

(1) Line No.	(2) Description	(3) Ref.	(4) Amount
1	Adjusted Jurisdictional Rate Base	B-1	$ 1,846,702
2	Weighted Cost of Debt	D-1	1.84%
3	Interest Deduction for Income Taxes		$ 33,979
4	Interest Deduction for Income Per Company		34,664
5	Increase in Deductible Interest		$ (685)
6	Consolidated Income Tax Rate		38.575%
7	Reduction (Increase) to Income Tax Expense		**$ (264)**
8	Long Term Debt	D-1	1.80%
9	Short Term Debt	D-1	0.01%
10	Customer Deposits	D-1	0.03%
11	Weighted Cost of Debt		1.84%
12	GPC Total Company Jurisdictional Rate Base		**$ 1,883,901**

Gulf Power Company
Capital Structure
Projected Test Year Ended December 31, 2014
($000)

(1) Line No.	(2) Description	(3) Capitalization Jurisdiction Amount	(4) Ratio	(5) Cost of Capital	(6) Weighted Cost of Capital
1	**GPC Requested Capital Structure:**				
2	Long Term Debt	$ 685,025	36.36%	4.96%	1.80%
3	Short Term Debt	27,615	1.47%	0.82%	0.01%
4	Preferred Stock	79,085	4.20%	6.00%	0.25%
5	Common Stock	715,221	37.96%	11.50%	4.37%
6	Customer Deposits	20,943	1.11%	2.30%	0.03%
7	Deferred Income Tax	379,918	20.17%	0.00%	0.00%
8	FASB 109 Deferred Taxes	(25,718)	-1.37%	0.00%	0.00%
9	Investment Credit	1,812	0.10%	8.18%	0.01%
10	TOTAL	**$ 1,883,901**	**100.00%**		**6.47%**
11	**OPC Adjusted Capital Structure:**				
12	Long Term Debt	$ 685,025	36.36%	4.96%	1.80%
13	Short Term Debt	27,615	1.47%	0.82%	0.01%
14	Preferred Stock	79,085	4.20%	6.00%	0.25%
15	Common Stock	715,221	37.96%	**9.00%**	3.42%
16	Customer Deposits	20,943	1.11%	2.30%	0.03%
17	Deferred Income Tax	379,918	20.17%	0.00%	0.00%
18	FASB 109 Deferred Taxes	(25,718)	-1.37%	0.00%	0.00%
19	Investment Credit	1,812	0.10%	8.18%	0.01%
20	TOTAL	**$ 1,883,901**	**100.00%**		**5.52%**

RESUME OF DON SCOTT NORWOOD

Norwood Energy Consulting, L.L.C.

P. O. Box 30197
Austin, Texas 78755-3197
(512) 343-9077

SUMMARY

Scott Norwood is an energy consultant with over 30 years of experience in electric utility regulatory consulting, resource planning and energy procurement. His clients include government agencies, publicly-owned utilities, public service commissions, municipalities and various electric consumer interests. Mr. Norwood has presented expert testimony on electric restructuring, resource planning and ratemaking issues in regulatory proceedings in Arkansas, Georgia, Iowa, Illinois, Michigan, Missouri, New Jersey, Oklahoma, South Dakota, Texas, Virginia, Washington and Wisconsin.

Prior to founding Norwood Energy Consulting in January of 2004, Mr. Norwood was employed for 18 years by GDS Associates, Inc., a Marietta, Georgia based energy consulting firm. Mr. Norwood was a Principal of GDS and directed the firm's Deregulated Services Department which provided a range of consulting services including merchant plant due diligence studies, deregulated market price forecasts, power supply planning and procurement projects, electric restructuring policy analyses, and studies of power plant dispatch and production costs.

Before joining GDS, Mr. Norwood was employed by the Public Utility Commission of Texas as Manager of Power Plant Engineering from 1984 through 1986. He began his career in 1980 as Staff Electrical Engineer with the City of Austin's Electric Utility Department where he was in charge of electrical maintenance and design projects at three gas-fired power plants.

Mr. Norwood is a graduate of the college of electrical engineering of the University of Texas.

EXPERIENCE

Energy Planning and Procurement Services

Dell Computer Corporation – Negotiated retail power supply agreement for Dell's Round Rock, Texas facilities producing annual savings in excess of $2 million.

Texas Association of School Boards Electric Aggregation Program – Serve as TASB's consultant in the development, marketing and administration of a retail electric aggregation program consisting of 2,500 Texas schools with a total load

of over 300 MW. Program produced annual savings of more than $30 million in its first year.

Oklahoma Industrial Energy Consumers - Analyzed and drafted comments addressing integrated resource plan filings by Public Service Company of Oklahoma and Oklahoma Gas and Electric Company.

S.C. Johnson - Analyzed and presented testimony addressing Wisconsin Electric Power Company's $4.1 billion CPCN application to construct three coal-fired generating units in southeast Wisconsin.

Oklahoma Industrial Energy Consumers - Analyzed wind energy project ownership proposals by Oklahoma Gas and Electric Company and presented testimony addressing project economics and operational impacts.

City of Chicago, Illinois Attorney General, Illinois Citizens' Utility Board - Analyzed Commonwealth Edison's proposed divestiture of the Kincaid and State Line power plants to SEI and Dominion Resources.

Georgia Public Service Commission - Analyzed and presented testimony on Georgia Power Company's integrated resource plan in a certification proceeding for an eight unit, 640 MW combustion turbine facility.

South Dakota Public Service Commission - Evaluated integrated resource plan and power plant certification filing of Black Hills Power & Light Company.

Shell Leasing Co. - Evaluated market value of 540 MW western coal-fired power plant.

Community Energy Electric Aggregation Program – Served as Community Energy's consultant in the development, marketing and start-up of a retail electric aggregation program consisting of major charitable organizations and their donors in Texas.

Austin Energy – Conducted competitive solicitation for peaking capacity. Developed request for proposal, administered solicitation and evaluated bids.

Austin Energy - Provided technical assistance in the evaluation of the economic viability of the City of Austin's ownership interest in the South Texas Project.

Austin Energy - Assisted with regional production cost modeling analysis to assess production cost savings associated with various public power merger and power pool alternatives.

Sam Rayburn G&T Electric Cooperative - Conducted competitive solicitation for peaking capacity. Developed request for proposal, administered solicitation and evaluated bids.

Rio Grande Electric Cooperative, Inc. - Directed preparation of power supply solicitation and conducted economic and technical analysis of offers.

Electric Restructuring Analyses

Electric Power Research Institute - Evaluated regional resource planning and power market dispatch impacts on rail transportation and coal supply procurement strategies and costs.

Arkansas House of Representatives – Critiqued proposed electric restructuring legislation and identified suggested amendments to provide increased protections for small consumers.

Virginia Legislative Committee on Electric Utility Restructuring – Presented report on status of stranded cost recovery for Virginia's electric utilities.

Georgia Public Service Commission – Developed models and a modeling process for preparing initial estimates of stranded costs for major electric utilities serving the state of Georgia.

City of Houston – Evaluated and recommended adjustments to Reliant Energy's stranded cost proposal before the Public Utility Commission of Texas.

Oklahoma Attorney General – Evaluated and advised the Attorney General on technical, economic and regulatory policy issues arising from various electric restructuring proposals considered by the Oklahoma Electric Restructuring Advisory Committee.

State of Hawaii Department of Business, Economics and Tourism – Evaluated electric restructuring proposals and developed models to assess the potential savings from deregulation of the Oahu power market.

Virginia Attorney General - Served as the Attorney General's consultant and expert witness in the evaluation of electric restructuring legislation, restructuring rulemakings and utility proposals addressing retail pilot programs, stranded costs, rate unbundling, functional separation plans, and competitive metering.

Western Public Power Producers, Inc. - Evaluated operational, cost and regional competitive impacts of the proposed merger of Southwestern Public Service Company and Public Service Company of Colorado.

Iowa Department of Justice, Consumer Advocate Division - Analyzed stranded investment and fuel recover issues resulting from a market-based pricing proposal submitted by MidAmerican Energy Company.

Cullen Weston Pines & Bach/Citizens' Utility Board - Evaluated estimated costs

and benefits of the proposed merger of Wisconsin Energy Corporation and Northern States Power Company (Primergy).

City of El Paso - Evaluated merger synergies and plant valuation issues related to the proposed acquisition and merger of El Paso Electric Company and Central & Southwest Company.

Rio Grande Electric Cooperative, Inc. - Analyzed stranded generation investment issues for Central Power & Light Company.

Regulatory Consulting

Oklahoma Industrial Energy Consumers - Assisted client with technical and economic analysis of proposed EPA regulations and compliance plans involving control of air emissions and potential conversion of coal-to-gas conversion options.

New York Public Service Commission - Conducted inter-company statistical benchmarking analysis of Consolidated Edison Company to provide the New York Public Service Commission with guidance in determining areas that should be reviewed in detailed management audit of the company.

Oklahoma Industrial Energy Consumers - Analyzed and presented testimony on affiliate energy trading transactions by AEP in ERCOT.

Georgia Public Service Commission - Presented testimony before the Georgia Public Service Commission in Docket 3840-U, providing recommendations on nuclear O&M levels for Hatch and Vogtle and recommending that a nuclear performance standard be implemented in the State of Georgia.

Oklahoma Industrial Energy Consumers - Analyzed and presented testimony addressing power production and coal plant dispatch issues in fuel prudence cases involving Oklahoma Gas and Electric Company.

Georgia Public Service Commission - Analyzed and provided recommendations regarding the reasonableness of nuclear O&M costs, fossil O&M costs and coal inventory levels reported in GPC's 1990 Surveillance Filing.

New York Public Service Commission - Conducted inter-company statistical benchmarking analysis of Rochester Gas & Electric Company to provide the New York Public Service Commission with guidance in determining areas which should be reviewed in detailed management audit of the company.

Oklahoma Attorney General – Analyzed and presented testimony regarding fuel and purchased power, depreciation and other expense items in Oklahoma Gas & Electric Company's 2001 rate case before the Oklahoma Corporation Commission.

City of Houston - Analyzed and presented testimony regarding fossil plant O&M expense levels in Houston Lighting & Power Company's rate case before the Public Utility Commission of Texas.

City of El Paso - Analyzed and presented testimony regarding regulatory and technical issues related to the Central & Southwest/El Paso Electric Company merger and rate proceedings before the PUCT, including analysis of merger synergy studies, fossil O&M and purchased power margins.

Residential Ratepayer Consortium - Analyzed Fermi 2 replacement power and operating performance issues in 1994 and 1995 fuel reconciliation proceedings for Detroit Edison Company before the Michigan Public Service Commission.

Residential Ratepayer Consortium - Analyzed and prepared testimony addressing coal plant outage rate projections in the Consumer's Power Company fuel proceeding before the Michigan Public Service Commission.

City of El Paso - Analyzed and developed testimony regarding Palo Verde operations and maintenance expenses in El Paso Electric Company's 1991 rate case before the Public Utility Commission of Texas.

City of Houston - Analyzed and developed testimony regarding the operations and maintenance expenses and performance standards for the South Texas Nuclear Project, and operations and maintenance expenses for the Limestone and Parish coal-fired power plants in HL&P's 1991 rate case before the PUCT.

City of El Paso - Analyzed and developed testimony regarding Palo Verde operations and maintenance expenses in El Paso Electric Company's 1990 rate case before the Public Utility Commission of Texas. Recommendations were adopted.

Power Plant Management

City of Austin Electric Utility Department - Analyzed the 1994 Operating Budget for the South Texas Nuclear Project (STNP) and assisted in the development of long-term performance and expense projections and divestiture strategies for Austin's ownership interest in the STNP.

City of Austin Electric Utility Department - Analyzed and provided recommendations regarding the 1991 capital and O&M budgets for the South Texas Nuclear Project.

Sam Rayburn G&T Electric Cooperative - Developed and conducted operational monitoring program relative to minority owner's interest in Nelson 6 Coal Station operated by Gulf States Utilities.

KAMO Electric Cooperative, City of Brownsville and Oklahoma Municipal Power Agency - Directed an operational audit of the Oklaunion coal-fired power plant.

Sam Rayburn G&T Electric Cooperative - Conducted a management/technical assessment of the Big Cajun II coal-fired power plant in conjunction with ownership feasibility studies for the project.

Kamo Electric Power Cooperative - Developed and conducted operational monitoring program for client's minority interest in GRDA Unit 2 Coal Fired Station.

Northeast Texas Electric Cooperative - Developed and conducted operational monitoring program concerning NTEC's interest in Pirkey Coal Station operated by Southwestern Electric Power Company and Dolet Hills Station operated by Central Louisiana Electric Company.

Corn Belt Electric Cooperative/Central Iowa Power Cooperative - Perform operational monitoring and budget analysis on behalf of co-owners of the Duane Arnold Energy Center.

PRESENTATIONS

Quantifying Impacts of Electric Restructuring: Dynamic Analysis of Power Markets, 1997 NARUC Winter Meetings, Committee on Finance and Technology.

Quantifying Costs and Benefits of Electric Utility Deregulation: Dynamic Analysis of Regional Power Markets, International Association for Energy Economics, 1996 Annual North American Conference.

Railroad Rates and Utility Dispatch Case Studies, 1996 EPRI Fuel Supply Seminar.

Quantifying Potentially Stranded Costs: Modeling and Policy Issues, 1996 NASUCA Annual Meeting.

TESTIMONY OF DON SCOTT NORWOOD
SINCE 2003

NO.	FILING DATE	REGULATORY AGENCY/COURT	DOCKET/CASE	UTILITY APPLICANT	ISSUES
1	01/27/03	Texas Public Utility Commission	26186	Southwestern Public Service Company (Direct)	Reasonableness of Reconcilable Fuel and Purchased Power Expenses for 24 month Reconciliation Period
2	02/10/03	Texas Public Utility Commission	27320	Reliant Energy Retail Services, LLC (Direct)	Reasonableness of Proposed Increase to PTB Fuel Factor and the Reasonableness of Rate Case Expenses
3	04/09/03	Texas Public Utility Commission	27035	Central Power and Light Company (Direct)	Reasonableness of CPL's Request to Reconcile Fuel Costs
4	04/10/03	Texas Public Utility Commission	26194	El Paso Electric Company (Direct)	Reasonableness of EPE's Request to Reconcile Fuel Costs
5	06/26/03	Texas Public Utility Commission	27956	Reliant Energy, and Retail Services, LCC (Direct)	Reasonableness of Reliant's Proposal to Increase PTB Fuel Factors
6	07/07/03	Public Service Commission of Wisconsin	05-CE-130	Wisconsin Electric Power Company (Direct)	Reasonableness of Input Assumptions and Results of Economic Analysis of ERGS
7	07/18/03	Texas Public Utility Commission	27576	Texas-New Mexico Power Company (Direct)*	Reasonableness of TNMP's Application for Final Reconciliation of Fuel Costs
8	08/19/03	Texas Public Utility Commission	26000	West Texas Utilities Company (Remand Direct)	Reasonableness of WTU's Application to Reconcile Eligible Fuel Expenses and Fuel Factor Revenues
9	08/26/03	Public Service Commission of Wisconsin	05-CE-130	Wisconsin Electric Power Company (Rebuttal)	Reasonableness of FEIS Economic Analysis of ERGS
10	08/26/03	Public Service Commission of Wisconsin	05-CE-130	Wisconsin Electric Power Company (Surrebuttal)	Reasonableness of Input Assumptions and Results of Economic Analysis of ERGS
11	09/05/03	State Corporation Commission of Virginia	PUE-2003-00285	Virginia Electric and Power Company (Direct)	Reasonableness of VEPCO's natural gas, coal, and purchased energy price forecasts underlying the Company's Fuel Factor Proposal
12	10/28/03	Texas Public Utility Commission	26195	Texas Genco and CenterPoint Energy (Refiled Direct)	Reasonableness of Estimated Costs and Benefits under a Joint Operating Agreement
13	11/05/03	Texas Public Utility Commission	28045	Southwestern Public Service Company (Direct)	Reasonableness of SWEPCO's Application for Reconciliation of Fuel Costs
14	12/12/03	Michigan Public Service Commission	U-13808	The Detroit Edison Company (Direct)	Analysis and Recommendations regarding DECO's proposed 2004 PSCR Plan applications and PSCR factor
15	02/27/04	Oklahoma Corporation Commission	PUD 200400004	Oklahoma Gas and Electric (Direct)	Request for Approval of McClain PPA
16	03/26/04	Michigan Public Service Commission	U-13808	The Detroit Edison Company (Direct)	Rebuttal Testimony Addressing DECO's proposed 2004 PSCR Plan applications and PSCR factor
17	03/29/04	Texas Public Utility Commission	29206	Texas New Mexico Power Company	Reasonableness of TNMP's Application for Final True-up of Stranded Costs
18	06/01/04	Texas Public Utility Commission	29526	CenterPoint, TGN, Reliant	Reasonableness of Applicants' Application for Final True-up of Stranded Costs
19	07/19/04	State of Wisconsin Division of Hearings and Appeals	3-SE-01-41-0005-0019	Wisconsin Electric Power Company	Authority for construction of ERGS facilities in Lake Michigan lakebed.
20	07/24/04	State of Wisconsin Division of Hearings and Appeals	IH-04-03	Wisconsin Electric Power Company	Comparison of environmental, social, capital and operating costs of proposed ERGS SCPC units to IGCC alternatives
21	8/9/04	State of Wisconsin Division of Hearings and Appeals	3-SE-01-41-0005-0019	Wisconsin Electric Power Company	WEPCO's failure to conduct a practicable alternatives analysis for wetlands impact of the ERGS.
22	8/18/04	Texas Public Utility Commission	29526	CenterPoint, TGN, Reliant	Reasonableness of Applicants' request for interest on claimed stranded costs; contribution of capacity auction true-up to return on stranded costs.
23	09/02/04	Texas Public Utility Commission	29526	CenterPoint, TGN, Reliant	Reasonableness of Applicants' request for interest on claimed stranded costs; contribution of capacity auction true-up to return on stranded costs.
24	9/10/04	Texas Public Utility Commission	27035	AEP TCC	Level and cost of capacity included in TCC's summer on-peak block energy purchases
25	09/27/04	State of Wisconsin Division of Hearings and Appeals	3-SE-01-41-0005-0019	Wisconsin Electric Power Company	Authority for construction of ERGS facilities in Lake Michigan lakebed
26	10/26/04	Texas Public Utility Commission	29801	Southwestern Public Service Company (Direct)	Reasonableness of SWEPCO's Application for Reconciliation of Fuel Costs
27	11/22/04	Texas Public Utility Commission	29206	Texas New Mexico Power Company (Remand Direct)	Reasonableness of TNMP's Claim for Interest on Final True-up Costs
28	1/18/05	Texas Public Utility Commission	29703	AEP Texas North Company (Direct)	Reasonableness of TNC's Final True-up Costs

TESTIMONY OF DON SCOTT NORWOOD
SINCE 2003

NO.	FILING DATE	REGULATORY AGENCY/COURT	DOCKET/CASE	UTILITY APPLICANT	ISSUES
29	1/20/05	Michigan Public Service Commission	U-14274	Consumers Energy Company (Direct)	Reasonableness of CECO's proposed 2005 PSCR Plan
30	2/23/05	Texas Public Utility Commission	30143	El Paso Electric Company (Direct)	Reasonableness of EPE's Request to Reconcile Fuel Costs
31	5/26/05	State Corporation Commission of Virginia	PUE2005-0012	Craig-Botetourt ECI (Direct)	General Rate Case, Power Supply Procurement Process
32	7/25/05	Oklahoma Corporation Commission	PUD 2002-00754	Public Service Company of Oklahoma (Direct)	Energy Trading Margins Allocation
33	09/02/05	Texas Public Utility Commission	31056	AEP TCC (Direct)	Reasonableness of TCC's Final True-up Costs
34	9/12/05	Oklahoma Corporation Commission	PUD 2005-00151	Oklahoma Gas and Electric (Direct)	Revenue Requirements, planning prudence, cost allocation
35	11/28/05	Louisiana Public Service Commission	U-27469	tergy Gulf States, Inc. and Entergy Louisiana, Inc. (Direct	Reasonableness of Settlement on Avoided Energy Costs
36	11/29/05	State Corporation Commission of Virginia	PUE2005-00056	Appalachian Power Company (Direct)	General Rate Case, Environmental and Reliability Costs
37	4/17/06	Texas Public Utility Commission	32475	AEP TCC (Direct)	Reasonableness of TCC's Securitization Proposal
38	4/25/06	State Corporation Commission of Virginia	PUE2006-00032	Delmarva Power & Light Company (Direct)	General Rate Case, Purchased Power Costs
39	5/15/06	Texas Public Utility Commission	31994	Texas New Mexico Power Company (Direct)	Reasonableness of TNP's CTC Proposal
40	8/24/06	Texas Public Utility Commission	32758	AEP TCC (Direct)	Reasonableness of TCC's CTC Proposal
41	10/04/06	State Corporation Commission of Virginia	PUE2006-00065	Appalachian Power Company (Direct)	General Rate Case, Off-System Sales and Jurisdictional Allocation
42	8/24/06	Texas Public Utility Commission	32758	AEP TCC (Direct)	Reasonableness of TCC's CTC Proposal
43	12/15/06	Texas Public Utility Commission	32766	Southwestern Public Service Company (Direct)	General Rate Case, Purchased Power Costs, Market-Based Sales
44	1/25/07	Texas Public Utility Commission	33106	Texas New Mexico Power Company (Direct)	Reasonableness of TNMP's CTC Carrying Charge Proposal
45	1/30/07	Texas Public Utility Commission	32898	Southwestern Electric Power Company (Direct)	Reasonableness of Fuel and Purchased Power Costs
46	2/15/07	Texas Public Utility Commission	31461	AEP TNC (Direct)	Reasonableness of TNC's CTC Proposal
47	3/13/07	Texas Public Utility Commission	33309	AEP TCC (Direct)	Reasonableness of Proposed Cost Allocation, Rate Design and Tariffs
48	3/13/07	Texas Public Utility Commission	33310	AEP TNC (Direct)	Reasonableness of Proposed Cost Allocation, Rate Design and Tariffs
49	3/20/07	Oklahoma Corporation Commission	PUD 2006-00285	Public Service Company of Oklahoma (Direct)	Non-fuel O&M, fuel costs, energy trading margins, purchased capacity costs
50	4/9/07	Oklahoma Corporation Commission	PUD 2006-00285	Public Service Company of Oklahoma (Rebuttal)	Non-fuel O&M, fuel costs, energy trading margins, purchased capacity costs
51	4/27/07	Texas Public Utility Commission	33687	Entergy Gulf States, Inc.	Transition to Competition Plan
52	5/21/07	Oklahoma Corporation Commission	PUD 2006-00030	Public Service Company of Oklahoma (Direct)	Prudence of Red Rock Generating Plant
53	5/21/07	Oklahoma Corporation Commission	PUD 2007-00012	Oklahoma Gas & Electric Company (Direct)	Prudence of Red Rock Generating Plant
54	6/8/07	Texas Public Utility Commission	33734	AEP/ETT	Formation of ETT Transmission Utility
55	6/18/07	Oklahoma Corporation Commission	PUD 2006-00030	Public Service Company of Oklahoma (Rebuttal)	Prudence of Red Rock Generating Plant
56	6/18/07	Oklahoma Corporation Commission	PUD 2007-00012	Oklahoma Gas & Electric Company (Rebuttal)	Prudence of Red Rock Generating Plant

TESTIMONY OF DON SCOTT NORWOOD
SINCE 2003

NO.	FILING DATE	REGULATORY AGENCY/COURT	DOCKET/CASE	UTILITY APPLICANT	ISSUES
57	6/19/07	Arkansas Public Service Commission	04-113-U	Entergy Arkansas Inc. (Direct)	Calculation of Avoided Energy Costs
58	7/24/07	Arkansas Public Service Commission	04-113-U	Entergy Arkansas Inc. (Surrebuttal)	Calculation of Avoided Energy Costs
59	9/26/07	Texas Public Utility Commission	34470	Southwestern Public Service Company (Direct)	System Loss Evaluation
60	10/01/07	State Corporation Commission of Virginia	PUE-2007-00067	Appalachian Power Company (Direct)	Fuel Factor Evaluation
61	10/03/07	State Corporation Commission of Virginia	PUE-2007-00069	Appalachian Power Company (Direct)	Environmental and Reliability Surcharge
62	11/02/07	State Corporation Commission of Virginia	PUE-2007-00066	Dominion Virginia Power (Direct)	Wise County Coal Plant Application
63	12/10/07	State Corporation Commission of Virginia	PUE-2007-00068	Appalachian Power Company (Direct)	WV IGCC Power Plant Proposal
64	1/18/08	Texas Public Utility Commission	34410	AEP TCC (Direct)	Oklaunion Sale True-up
65	4/4/08	Oklahoma Corporation Commission	PUE 2007-00365	Public Service Company of Oklahoma (Direct)	Fuel Prudence Review
66	4/11/08	Texas Public Utility Commission	34800	Entergy Gulf States, Inc. (Direct)	Fuel Reconciliation Case
67	5/15/08	Oklahoma Corporation Commission	PUD 2007-00364	Oklahoma Gas & Electric Company (Direct)	Fuel Prudence Review
68	5/23/08	Texas Public Utility Commission	33672	ERCOT (Direct)	Competitive Renewable Energy Zones for Wind Generation
69	6/3/08	Texas Public Utility Commission	33672	ERCOT (Rebuttal)	Competitive Renewable Energy Zones for Wind Generation
70	6/12/07	State Corporation Commission of Virginia	PUE-2008-00039	Dominion Virginia Power (Direct)	Fuel Factor Application
71	7/11/08	Oklahoma Corporation Commission	PUD 2008-00148	Oklahoma Gas & Electric Company (Direct)	Proposed Transmission for Wind Generation
72	7/17/08	Oklahoma Corporation Commission	PUD 2007-00364	Oklahoma Gas & Electric Company (Rebuttal)	Fuel Prudence Review
73	8/13/08	State Corporation Commission of Virginia	PUE-2008-00045	Appalachian Power Company (Direct)	Environmental and Reliability Surcharge
74	9/26/08	State Corporation Commission of Virginia	PUE-2008-00046	Appalachian Power Company (Direct)	Capacity Equalization, capital additions, production O&M
75	10/3/08	State Corporation Commission of Virginia	PUE-2008-00033	Potomac Edison Company (Direct)	Purchased Power Cost Recovery
76	10/13/08	Texas Public Utility Commission	35763	Southwestern Public Service Company (Direct)	Incremental Cost of Wholesale Sales, OSS and Commodity Trading Margins
77	10/29/08	Oklahoma Corporation Commission	PUE 2008-00144	Public Service Company of Oklahoma (Direct)	Capital additions, affiliate charges, corporate strategy
78	11/5/08	Oklahoma Corporation Commission	PUE 2008-00144	Public Service Company of Oklahoma (Direct)	Base rate fuel costs, reactive power charges
79	1/7/09	Texas Public Utility Commission	36324	Southwestern Electric Power Company (Direct)	Interim Fuel Factor Proposal
80	6/23/09	State Corporation Commission of Virginia	PUE-2009-00038	Appalachian Power Company (Direct)	Fuel Factor Evaluation
81	6/24/09	Oklahoma Corporation Commission	PUD 2008-00398	Oklahoma Gas & Electric Company (Direct)	General Rate Case, Rate Design Issues
82	6/25/09	State Corporation Commission of Virginia	PUE-2009-00016	Dominion Virginia Power (Direct)	Fuel Factor Application
83	8/27/09	State Corporation Commission of Virginia	PUE-2009-00039	Appalachian Power Company (Direct)	Environmental and Reliability Surcharge
84	9/29/09	Oklahoma Corporation Commission	PUD 2009-00167	Oklahoma Gas & Electric Company (Direct)	Certification of OU Spirit Wind Generation Project
85	11/2/09	State Corporation Commission of Virginia	PUE-2009-00019	Dominion Virginia Power (Direct)	General Rate Case

TESTIMONY OF DON SCOTT NORWOOD
SINCE 2003

NO.	FILING DATE	REGULATORY AGENCY/COURT	DOCKET/CASE	UTILITY APPLICANT	ISSUES
86	11/17/09	Washington Utilities and Trade Commission	UE-090704	Puget Sound Energy (Direct)	General Rate Case
87	12/28/09	State Corporation Commission of Virginia	PUE-2009-00030	Appalachian Power Company (Direct)	Base rate case, capacity equalization charges
88	1/13/10	State Corporation Commission of Virginia	PUE-2009-00081	Dominion Virginia Power (Direct)	DSM Cost Recovery, Voltage Reduction Program
89	1/28/10	Washington Utilities and Trade Commission	UE-070725	Puget Sound Energy (Direct)	Ratemaking Treatment of REC Sale Proceeds
90	3/17/10	Oklahoma Corporation Commission	PUE 2009-00158	Public Service Company of Oklahoma (Direct)	Affiliate Energy Trading Costs
91	5/6/10	Texas Public Utility Commission	37162	Southwestern Electric Power Company (Direct)	Energy Trading Margin Refund
92	6/11/10	Oklahoma Corporation Commission	PUD 2010-00037	Oklahoma Gas & Electric Company (Direct)	Crossroads Wind Generation Project
93	7/6/10	Texas Public Utility Commission	38361	El Paso Electric Company (Direct)	Mine Reclamation Costs
94	7/12/10	Texas Public Utility Commission	37162	Southwestern Electric Power Company (Direct)	Affiliate Energy Trading Costs
95	7/20/10	Oklahoma Corporation Commission	PUE 2009-00158	Public Service Company of Oklahoma (Surrebuttal)	Affiliate Energy Trading Costs
96	9/10/10	Texas Public Utility Commission	38339	CenterPoint Energy Houston Electric, LLC (Direct)	Storm Hardening and Distribution O&M Expenses
97	10/05/10	Oklahoma Corporation Commission	PUE 2010-00092	Public Service Company of Oklahoma (Direct)	Wind Energy PPA, REC Treatment
98	10/26/10	Oklahoma Corporation Commission	PUE 2010-00050	Public Service Company of Oklahoma (Direct)	Base Rate Case
97	1/7/11	State Corporation Commission of Virginia	PUE-2010-00126	Northern Virginia Electric Cooperative (Direct)	Biomass Power Plant CPCN
98	1/14/11	Oklahoma Corporation Commission	PUD 2010-00146	Oklahoma Gas & Electric Company (Direct)	SPP Cost Tracker
99	3/11/11	Oklahoma Corporation Commission	PUD 2010-00175	Oklahoma Gas & Electric Company (Direct)	2009 Fuel Prudence Review
100	3/15/11	Arkansas Public Service Commission	10-067-U	Oklahoma Gas & Electric Company (Direct)	Coal Inventory, Production O&M, ECR Revisions
99	4/1/11	Oklahoma Corporation Commission	PUD 2010-00172	Public Service Company of Oklahoma (Direct)	Fuel Prudence Review
100	7/20/11	State Corporation Commission of Virginia	PUE-2011-00037	Appalachian Power Company (Direct)	Base rate case, capacity equalization charges
101	7/21/11	State Corporation Commission of Virginia	PUE-2011-00027	Dominion Virginia Power (Direct)	Performance Incentive Program
102	7/29/11	State Corporation Commission of Virginia	PUE-2011-00035	Appalachian Power Company (Direct)	Environmental Compliance Rate Adjustment Clause
103	8/23/11	State Corporation Commission of Virginia	PUE-2011-00034	Appalachian Power Company (Direct)	RPS Rate Adjustment Clause
104	9/12/11	Texas Public Utility Commission	39504	CenterPoint Energy Houston Electric, LLC (Direct)	Stranded Cost Remand
105	9/16/11	Oklahoma Corporation Commission	PUD 2011-00106	Public Service Company of Oklahoma (Direct)	SPP Transmission Cost Recovery Rider
106	11/22/11	State Corporation Commission of Virginia	PUE-2011-00073	Dominion Virginia Power (Direct)	Biomass Conversion Project
107	12/7/11	Washington Utilities and Trade Commission	UE-111048	Puget Sound Energy (Direct)	Lower Snake River Wind Generation Project
108	1/17/12	State Corporation Commission of Virginia	PUE-2011-00093	Dominion Virginia Power (Direct)	DSM Program Evaluation and Cost Recovery
109	2/8/12	Oklahoma Corporation Commission	PUD 2011-00186	Oklahoma Gas & Electric Company (Direct)	OSU Special Contract

TESTIMONY OF DON SCOTT NORWOOD
SINCE 2003

NO.	FILING DATE	REGULATORY AGENCY/COURT	DOCKET/CASE	UTILITY APPLICANT	ISSUES
110	4/6/12	Oklahoma Corporation Commission	PUD 2011-00132	Oklahoma Gas & Electric Company (Direct)	2010 Fuel Prudence Review
111	4/30/12	Oklahoma Corporation Commission	PUD 2011-00129	Public Service Company of Oklahoma (Direct)	2010 Fuel Prudence Review
112	6/21/12	Texas Public Utility Commission	40020	Lone Star Transmission, LLC (Direct)	Transmission O&M Expenses
113	9/14/12	Oklahoma Corporation Commission	PUD 2011-00186	Oklahoma Gas & Electric Company (Direct)	SPP Cost Rider
114	12/10/12	Texas Public Utility Commission	40443	Southwestern Electric Power Company (Direct)	Turk Settlement Costs, Welsh 2 Retirement, Production O&M
115	1/8/13	Oklahoma Corporation Commission	PUD 2012-00054	Public Service Company of Oklahoma (Direct)	Environmental Compliance Plan
116	2/11/13	Oklahoma Corporation Commission	PUD 2012-00054	Public Service Company of Oklahoma (Rebuttal)	Environmental Compliance Plan
117	3/1/13	State Corporation Commission of Virginia	PUE-2012-00128	Dominion Virginia Power (Direct)	Brunswick CCCT CCN
118	3/22/13	Oklahoma Corporation Commission	PUD 2012-00054	Public Service Company of Oklahoma (Surrebuttal)	Environmental Compliance Plan
119	1/8/13	Oklahoma Corporation Commission	PUD 2012-00054	Public Service Company of Oklahoma (Direct)	Environmental Compliance Plan
120	4/23/13	State Corporation Commission of Virginia	PUE-2012-00141	Appalachian Power Company (Direct)	Coal-fired Generating Asset Transfers
121	7/31/13	State Corporation Commission of Virginia	PUE-2013-00020	Dominion Virginia Power (Direct)	Performance Incentive Program, Nuclear Outage Costs, Storm Expense

Docket Nos. 130140-EI, 130151-EI, 130092-EI
Confidential Exhibit SN-2
Transmission Upgrade Project Descriptions

Gulf Power Company
Ten Year Transmission Plans
2012 Assessments for Planning Horizon 2013-2022

Confidential in its entirety

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130140-EI EXHIBIT 32
PARTY Office of Public Counsel (OPC) Direct
DESCRIPTION Scott Norwood (SN-2) (CONFIDENTIAL)
DATE

Citizens' Fourth Request to Produce Documents
Docket No. 130140-EI
GULF POWER COMPANY
September 25, 2013
Item No. 76
Page 1 of 1

76. Transmission. Please provide copies of all operating policies that specify the criteria and conditions governing must-run generation for the Plant Crist and Plant Smith generating units as described in the Company's response to OPC Interrogatory No. 118.

ANSWER:

Responsive electronic documents that include confidential information are located in the folder named OPC POD_076 CONF on the DVD labeled Docket No. 130140-EI Citizens' Fourth Request to Produce Documents (Nos. 74-89) Disk 2-Confidential. Hard copy documents that have been saved in electronic (PDF) format are saved in this folder and are page numbered 130140-OPC-POD-76-1 through 130140-OPC-POD-76-2.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130140-EI EXHIBIT 33
PARTY Office of Public Counsel (OPC) Direct
DESCRIPTION Scott Norwood (SN-3) (CONFIDENTIAL)
DATE

SYSTEM CONTROL POLICY ON GENERATOR UNIT MUST-RUN REQUIREMENTS

SUBJECT

GENERATOR MUST-RUN REQUIREMENTS

PURPOSE:

The purpose of this policy is to ensure that adequate generation is available to maintain system reliability, taking into account both high and low load situations and corresponding contingencies. This policy also provides a process to ensure that proper notification is made to the PCC for communicating with the trading floor for appropriate gas nominations.

Must-Run Rules

Crist Plant:

[redacted] at all times - one of which must be [redacted]
*Special arrangements must be made in advance when [redacted] have to be off at the same time.

Smith Plant:

System Load Level	L. Smith unit dispatch
85-100	[redacted]
70-85	
60-70	
50-60	
<50	

*System Load Levels are percentages of Summer Gross Weather Normal Loads. Based on Gulf Summer Gross of [redacted] (YR-2013)

*Special arrangements must be made in advance when [redacted] Smith units have to be off at the same time.

Instructions

Crist Plant:

1. Night Shift PSC to check the Unit Commitment Report for any Crist unit coming offline.
2. Ensure the Must-Run Application matches the current Unit Commitment Report.

Smith Plant:

1. Night Shift PSC to check the Unit Commitment Report for any Smith unit coming offline.
2. Ensure the Must-Run Application matches the current Unit Commitment Report.

Responsibility

It is the responsibility of the System Operations Manager and the Transmission Control Center Supervisor to ensure that this procedure is followed.

Citizens' Fourth Request to Produce Documents
Docket No. 130140-EI
GULF POWER COMPANY
September 25, 2013
Item No. 78
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78. Transmission. Please provide all studies or analyses documenting the basis for the decisions to implement must-run operations at the Plant Smith and Plant Crist units as identified in the Company's response to OPC Interrogatory No. 140.

ANSWER:

There are no studies or analyses documenting the initial determination of Plant Crist and Plant Smith as must-run facilities.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130140-EI EXHIBIT 34
PARTY Office of Public Counsel (OPC) Direct
DESCRIPTION Scott Norwood (SN-4)
DATE

Citizens' Fourth Set of Interrogatories
Docket No. 130140-EI
GULF POWER COMPANY
September 25, 2013
Item No. 123
Page 1 of 2

123. Transmission. Please provide the number of hours in each month over the last five calendar years that each of the Company's Plant Crist and Plant Smith generating units were operated primarily to meet must-run conditions rather than for economic dispatch purposes.

ANSWER:

The information as requested is not available. The Company does not have the granularity in its historical operating data to determine which hours a specific unit was committed solely for transmission reliability must run requirements. Typically, units are committed and dispatched based upon a combination of operational factors which influence the dispatch economics for any particular hour of operation. For example, because steam units require many hours to start-up, a unit which will be needed and would have been in economic dispatch to serve a daily peak must be committed (or kept on line) during the off-peak hours as well, even though its relative economics during those off-peak hours may be less attractive.

Many other factors influence unit commitment and dispatch economics as well. Examples include testing plant equipment, meeting environmental limits, storm considerations, short-term fuel pricing volatility, maintenance outages, unplanned outages, area voltage support, and transmission reliability must run.

Due to the high number of constraints, we use a complex set of optimization models that concurrently meet the system constraints in the most cost effective manner for Gulf Power's customers. The number of constraints being managed and the significant overlap between these constraints makes it impractical to differentiate between individual drivers in a historical assessment. Therefore, while Gulf can employ reasonable, simplifying assumptions for prospective modeling, historical data regarding unit operation does not allow Gulf to identify when the seven individual generating units at Plant Smith and Plant Crist were used "primarily to meet must-run conditions rather than for economic dispatch purposes" over the 43,800 hour, five-year period.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130140-EI EXHIBIT 35
PARTY Office of Public Counsel (OPC) Direct
DESCRIPTION Scott Norwood (SN-5)
DATE

Citizens' Fourth Set of Interrogatories
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GULF POWER COMPANY
September 25, 2013
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From a transmission planning perspective, reliability must run analysis assesses whether a specific unit is needed to meet transmission reliability criteria under any expected system conditions. The analysis used in the Gulf Power Company Environmental Compliance Program Update to quantify the transmission reliability "must-run" costs/benefits was a forward looking economic analysis that considered the impact of increased cost due to the MATS rule, the Company's strategies to comply with the MATS rule and the resulting impact on Gulf's customer costs. In this forward looking model, it is possible to isolate a single constraint, while holding the other constraints constant, and assess the cost impact over a time period. This approach was utilized to determine the cost impact to Gulf customers associated with transmission constraints that effectively alter the commitment and dispatch of the units at Smith and Crist.

Docket Nos. 130140-EI, 130151-EI, 130092-EI
Confidential Exhibit SN-6
October 2012 Plant Smith Retirement Analysis

Gulf Crist and Smith Update
October 1, 2012

Confidential in its entirety

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130140-EI EXHIBIT 36
PARTY Office of Public Counsel (OPC) Direct
DESCRIPTION Scott Norwood (SN-6) (CONFIDENTIAL)
DATE

GULF POWER COMPANY
PROPOSED DEPRECIATION FACTORS AND RATES
AT DECEMBER 31, 2013

Account	Account Name	12/31/2013 Plant Balance	Average Service Life	IRR Net Removal Excl. Dismantling Amount	IRR Net Removal Excl. Dismantling Percent	Reserve Requirement w/ Net Removal	12/31/2013 Accumulated Depreciation Reserve	Amount to be Recovered	Average Remaining Life	Recommended Annual Depreciation	Depreciation Rate
		$	Yrs	$	%	$	$	$	Years	$	%
STEAM PRODUCTION PLANT											
Plant Crist Common 4-7											
311	Structures and Improvements	$ 122,456,878	36.4	$ 1,500,097	1.2%	$ 43,248,725	$ 40,140,631	$ 83,816,344	23.7	$ 3,536,555	2.89%
312	Boiler Plant Equipment	$ 473,369,675	26.9	$ 15,076,824	3.2%	$ 79,001,455	$ 73,323,971	$ 415,122,528	22.5	$ 18,409,645	3.89%
314	Turbogenerator Units	$ 26,920,570	34.6	$ 1,121,242	4.2%	$ 10,292,804	$ 9,553,106	$ 18,488,708	21.9	$ 844,233	3.14%
315	Accessory Electric Equipment	$ 95,875,088	28.9	$ 2,348,940	2.5%	$ 20,052,856	$ 18,611,561	$ 79,812,467	23.0	$ 3,461,412	3.61%
316	Misc. Power Plant Equipment	$ 12,203,409	25.7	$ 747,459	6.1%	$ 2,519,624	$ 2,338,550	$ 10,612,318	20.7	$ 512,672	4.20%
	Subtotal	$ 730,825,620	28.6	$ 20,794,561	2.8%	$ 155,115,263	$ 143,967,819	$ 607,852,362	22.70	$ 26,764,516	3.66%
Plant Crist Unit #4											
311	Structures and Improvements	$ -									
312	Boiler Plant Equipment	$ 32,345,400	23.2	$ 441,515	1.4%	$ 18,454,387	$ 17,128,152	$ 15,658,762	10.1	$ 1,544,000	4.77%
314	Turbogenerator Units	$ 10,116,143	21.4	$ 180,573	1.8%	$ 5,485,167	$ 5,090,972	$ 5,205,744	10.0	$ 520,574	5.15%
315	Accessory Electric Equipment	$ 3,454,218	21.7	$ 36,269	1.1%	$ 1,849,797	$ 1,716,861	$ 1,773,627	10.2	$ 173,885	5.03%
316	Misc. Power Plant Equipment	$ -									
	Subtotal	$ 45,915,761	22.7	$ 658,357	1.4%	$ 25,789,351	$ 23,935,985	$ 22,638,133	10.11	$ 2,238,459	4.88%
Plant Crist Unit #5											
311	Structures and Improvements	$ -									
312	Boiler Plant Equipment	$ 34,665,998	24.0	$ 563,322	1.6%	$ 17,626,128	$ 16,359,417	$ 18,869,904	12.0	$ 1,573,516	4.54%
314	Turbogenerator Units	$ 12,976,335	17.9	$ 275,747	2.1%	$ 4,516,073	$ 4,191,823	$ 9,060,560	11.8	$ 767,844	5.92%
315	Accessory Electric Equipment	$ 3,139,986	22.1	$ 39,250	1.3%	$ 1,438,568	$ 1,335,185	$ 1,844,061	12.1	$ 152,401	4.85%
316	Misc. Power Plant Equipment	$ -									
	Subtotal	$ 50,782,319	22.0	$ 878,319	1.7%	$ 23,580,789	$ 21,886,124	$ 29,774,514	11.94	$ 2,493,761	4.91%
Plant Crist Unit #6											
311	Structures and Improvements	$ -									
312	Boiler Plant Equipment	$ 259,851,934	22.8	$ 7,262,862	2.8%	$ 32,830,664	$ 30,471,270	$ 236,643,528	20.0	$ 11,833,545	4.55%
314	Turbogenerator Units	$ 47,404,661	24.7	$ 1,732,640	3.7%	$ 10,344,695	$ 9,601,268	$ 39,536,034	19.5	$ 2,027,489	4.28%
315	Accessory Electric Equipment	$ 31,688,605	23.8	$ 681,305	2.2%	$ 4,760,281	$ 4,418,181	$ 27,951,729	20.3	$ 1,376,932	4.35%
316	Misc. Power Plant Equipment	$ -									
	Subtotal	$ 338,945,200	23.1	$ 9,676,807	2.9%	$ 47,935,640	$ 44,490,718	$ 304,131,289	19.96	$ 15,237,966	4.50%
Plant Crist Unit #7											
311	Structures and Improvements	$ -									
312	Boiler Plant Equipment	$ 206,674,810	31.4	$ 6,582,593	3.2%	$ 60,111,506	$ 55,791,559	$ 157,465,843	22.5	$ 6,983,216	3.38%
314	Turbogenerator Units	$ 78,417,397	29.1	$ 3,266,085	4.2%	$ 20,210,346	$ 18,757,918	$ 62,925,583	21.9	$ 2,873,313	3.66%
315	Accessory Electric Equipment	$ 28,881,007	33.8	$ 707,585	2.5%	$ 9,454,343	$ 8,774,901	$ 20,813,690	23.0	$ 904,943	3.13%
316	Misc. Power Plant Equipment	$ -									
	Subtotal	$ 313,973,214	31.0	$ 10,556,262	3.4%	$ 89,776,195	$ 83,324,379	$ 241,205,097	22.41	$ 10,761,472	3.43%
Total Plant Crist Depreciable		$ 1,480,442,114	27.09	$ 42,564,307	2.9%	$ 342,197,218	$ 317,605,025	$ 1,206,401,396	20.96	$ 57,496,175	3.88%
310	Easements	$ -					$ 420				

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130140-EI EXHIBIT 37
PARTY Office of Public Counsel (OPC) Direct
DESCRIPTION Jacob Pous (JP- 1)

GULF POWER COMPANY
PROPOSED DEPRECIATION FACTORS AND RATES
AT DECEMBER 31, 2013

Account	Account Name	12/31/2013 Plant Balance $	Average Service Life Yrs	IRR Net Removal Excl. Dismantling Amount $	IRR Net Removal Excl. Dismantling Percent %	Reserve Requirement w/ Net Removal $	12/31/2013 Accumulated Depreciation Reserve $	Amount to be Recovered $	Average Remaining Life Years	Recommended Annual Depreciation $	Depreciation Rate %
Plant Crist Other Recovery/Non-Depreciable											
310	Land	$ 6,023,266					$ -				
312	Base Coal	$ 141,840					$ 141,840				
316	Amortization Property (5 yr.)	$ 137,572					$ 86,586				
316	Amortization Property (7 yr.)	$ 2,678,299					$ 1,425,704				
317	ARO	$ 1,132,431					$ 721,122				
	Dismantlement						$ 73,645,939				
TOTAL PLANT CRIST		$ 1,490,555,522					$ 393,626,636				
Plant Scholz Common											
311	Structures and Improvements	$ 6,225,461	31.1	$ 4,669	0.1%	$ 5,929,642	$ 6,230,130	$ -	1.5	$ -	0.00%
312	Boiler Plant Equipment	$ 6,035,087	21.4	$ 11,768	0.2%	$ 5,625,077	$ 6,032,994	$ 13,862	1.5	$ 9,286	0.15%
314	Turbogenerator Units	$ 1,115,804	13.1	$ 2,845	0.3%	$ 990,560	$ 1,062,393	$ 56,257	1.5	$ 37,504	3.36%
315	Accessory Electric Equipment	$ 3,202,528	31.8	$ 4,804	0.2%	$ 3,056,043	$ 3,207,332	$ -	1.5	$ -	0.00%
316	Misc. Power Plant Equipment	$ 453,566	8.8	$ 1,701	0.4%	$ 377,665	$ 405,052	$ 50,215	1.5	$ 33,477	7.38%
	Subtotal	$ 17,032,446	23.7	$ 25,787	0.2%	$ 15,978,985	$ 16,937,900	$ 120,333	1.50	$ 80,267	0.47%
Plant Scholz Unit #1											
311	Structures and Improvements	$ -									
312	Boiler Plant Equipment	$ 4,689,139	34.2	$ 9,144	0.2%	$ 4,493,222	$ 4,698,283	$ -	1.5	$ -	0.00%
314	Turbogenerator Units	$ 2,498,880	39.6	$ 6,372	0.3%	$ 2,410,356	$ 2,505,252	$ -	1.5	$ -	0.00%
315	Accessory Electric Equipment	$ 105,404	10.1	$ 158	0.2%	$ 89,885	$ 96,403	$ 9,159	1.5	$ 6,106	5.79%
316	Misc. Power Plant Equipment	$ -									
	Subtotal	$ 7,293,423	34.6	$ 15,674	0.2%	$ 6,993,463	$ 7,299,938	$ 9,159	1.50	$ 6,106	0.08%
Plant Scholz Unit #2											
311	Structures and Improvements	$ -									
312	Boiler Plant Equipment	$ 4,337,721	25.5	$ 8,459	0.2%	$ 4,091,768	$ 4,346,180	$ -	1.5	$ -	0.00%
314	Turbogenerator Units	$ 1,986,288	43.3	$ 5,065	0.3%	$ 1,922,369	$ 1,991,353	$ -	1.5	$ -	0.00%
315	Accessory Electric Equipment	$ 168,285	14.0	$ 252	0.2%	$ 150,480	$ 161,392	$ 7,145	1.5	$ 4,763	2.83%
316	Misc. Power Plant Equipment	$ -									
	Subtotal	$ 6,492,294	28.5	$ 13,776	0.2%	$ 6,164,617	$ 6,498,925	$ 7,145	1.50	$ 4,763	0.07%
Total Plant Scholz Depreciable		$ 30,818,163	26.6	$ 55,238	0.2%	$ 29,137,065	$ 30,736,763	$ 136,638	1.50	$ 91,137	0.30%
Plant Scholz Other Recovery/Non-Depreciable											
310	Land	$ 44,579					$ -				
312	Base Coal	$ 71,300					$ 71,300				
316	Amortization Property (5 yr.)	$ 8,730					$ 4,635				
316	Amortization Property (7 yr.)	$ 102,910					$ 61,526				
317	ARO	$ 242,640					$ 13,751,261				
	Dismantlement						$ 286,986				
TOTAL PLANT SCHOLZ		$ 31,288,322					$ 44,912,471				

GULF POWER COMPANY
PROPOSED DEPRECIATION FACTORS AND RATES
AT DECEMBER 31, 2013

Account	Account Name	12/31/2013 Plant Balance $	Average Service Life Yrs	IRR Net Removal Excl. Dismantling Amount $	IRR Net Removal Excl. Dismantling Percent %	Reserve Requirement w/ Net Removal $	12/31/2013 Accumulated Depreciation Reserve $	Amount to be Recovered $	Average Remaining Life Years	Recommended Annual Depreciation $	Depreciation Rate %
Plant Smith Common											
311	Structures and Improvements	$ 36,837,541	35.6	$ 340,747	0.9%	$ 18,275,844	$ 19,353,854	$ 17,824,434	18.1	$ 984,775	2.67%
312	Boiler Plant Equipment	$ 24,185,788	30.2	$ 581,668	2.4%	$ 10,507,563	$ 11,127,357	$ 13,640,100	17.4	$ 784,469	3.24%
314	Turbogenerator Units	$ 2,964,511	34.0	$ 93,234	3.1%	$ 1,528,872	$ 1,619,054	$ 1,438,691	17.0	$ 84,629	2.85%
315	Accessory Electric Equipment	$ 4,154,684	40.5	$ 76,862	1.9%	$ 2,392,652	$ 2,533,784	$ 1,697,762	17.6	$ 96,464	2.32%
316	Misc. Power Plant Equipment	$ 1,870,741	25.0	$ 86,522	4.6%	$ 673,298	$ 713,013	$ 1,244,250	16.4	$ 75,869	4.06%
	Subtotal	$ 70,013,265	33.3	$ 1,179,033	1.7%	$ 33,378,229	$ 35,347,061	$ 35,845,236	17.69	$ 2,026,206	2.89%
Plant Smith Unit #1											
311	Structures and Improvements	$ -									
312	Boiler Plant Equipment	$ 32,652,589	27.1	$ 700,398	2.1%	$ 14,134,790	$ 14,968,538	$ 18,384,449	15.6	$ 1,177,344	3.61%
314	Turbogenerator Units	$ 13,496,717	38.4	$ 378,583	2.8%	$ 8,346,860	$ 8,839,204	$ 5,036,096	15.3	$ 329,157	2.44%
315	Accessory Electric Equipment	$ 4,217,804	33.7	$ 69,594	1.7%	$ 2,277,282	$ 2,411,609	$ 1,875,789	15.8	$ 118,721	2.81%
316	Misc. Power Plant Equipment	$ -									
	Subtotal	$ 50,367,110	30.0	$ 1,148,575	2.3%	$ 24,758,932	$ 26,219,351	$ 25,296,334	15.56	$ 1,625,222	3.23%
Plant Smith Unit #2											
311	Structures and Improvements	$ -									
312	Boiler Plant Equipment	$ 42,290,474	30.3	$ 1,017,086	2.4%	$ 18,455,470	$ 19,544,076	$ 23,763,484	17.4	$ 1,366,685	3.23%
314	Turbogenerator Units	$ 12,536,935	37.9	$ 394,287	3.1%	$ 7,130,938	$ 7,551,560	$ 5,379,662	17.0	$ 316,451	2.52%
315	Accessory Electric Equipment	$ 1,596,035	45.9	$ 29,527	1.9%	$ 1,002,253	$ 1,061,371	$ 564,191	17.6	$ 32,056	2.01%
316	Misc. Power Plant Equipment	$ -									
	Subtotal	$ 56,423,444	32.0	$ 1,440,899	2.6%	$ 26,588,660	$ 28,157,006	$ 29,707,337	17.32	$ 1,715,192	3.04%
Total Plant Smith Depreciable		$ 176,803,819	31.9	$ 3,768,507	2.1%	$ 84,725,822	$ 89,723,419	$ 90,848,907	16.93	$ 5,366,619	3.04%
Plant Smith Other Recovery/Non-Depreciable											
310	Land	$ 1,363,924					$ -				
312	Base Coal	$ 108,300					$ 108,300				
316	Amortization Property (5 yr.)	$ 29,526					$ 15,715				
316	Amortization Property (7 yr.)	$ 1,174,466					$ 667,192				
317	ARO	$ 471,938					$ 21,657,782				
	Dismantlement						$ 350,848				
TOTAL PLANT SMITH		$ 179,951,973					$ 112,523,256				

Docket Nos. 130140-EI, 130151-EI, 130092-EI
Exhibit ___ (JP-1)
Recommended Depreciation Adjustments Summary
Page 3 of 9

GULF POWER COMPANY
PROPOSED DEPRECIATION FACTORS AND RATES
AT DECEMBER 31, 2013

Account	Account Name	12/31/2013 Plant Balance	Average Service Life	IRR Net Removal Excl. Dismantling Amount	IRR Net Removal Excl. Dismantling Percent	Reserve Requirement w/ Net Removal	12/31/2013 Accumulated Depreciation Reserve	Amount to be Recovered	Average Remaining Life	Recommended Annual Depreciation	Depreciation Rate
		$	Yrs	$	%	$	$	$	Years	$	%
Plant Daniel #1-2 Common											
311	Structures and Improvements	$ 13,441,253	51.0	$ 218,420	1.6%	$ 5,303,167	$ 6,789,975	$ 6,869,698	31.2	$ 220,183	1.64%
312	Boiler Plant Equipment	$ 31,539,058	51.7	$ 1,332,525	4.2%	$ 14,390,259	$ 18,424,743	$ 14,446,840	29.1	$ 497,015	1.58%
314	Turbogenerator Units	$ 3,484,941	53.0	$ 192,543	5.5%	$ 1,734,662	$ 2,220,996	$ 1,456,488	28.0	$ 52,017	1.49%
315	Accessory Electric Equipment	$ 1,215,206	44.7	$ 39,494	3.3%	$ 415,426	$ 531,896	$ 722,804	29.9	$ 24,174	1.99%
316	Misc. Power Plant Equipment	$ 2,127,402	47.2	$ 172,851	8.1%	$ 1,038,038	$ 1,329,065	$ 971,189	25.9	$ 37,498	1.76%
	Subtotal	$ 51,807,860	51.2	$ 1,955,834	3.8%	$ 22,881,553	$ 29,296,675	$ 24,467,019	29.45	$ 830,887	1.60%
Plant Daniel #1-4 Common											
311	Structures and Improvements	$ 4,587,856	59.5	$ 74,553	1.6%	$ 2,217,583	$ 2,839,309	$ 1,823,100	31.2	$ 58,433	1.27%
312	Boiler Plant Equipment	$ 3,051,458	42.0	$ 128,924	4.2%	$ 979,316	$ 1,253,880	$ 1,926,503	29.1	$ 66,278	2.17%
314	Turbogenerator Units	$ -									
315	Accessory Electric Equipment	$ 138,010	36.8	$ 4,485	3.3%	$ 26,718	$ 34,209	$ 108,287	29.9	$ 3,622	2.62%
316	Misc. Power Plant Equipment	$ 1,107,637	36.1	$ 89,996	8.1%	$ 338,389	$ 433,261	$ 764,372	25.9	$ 29,512	2.66%
	Subtotal	$ 8,884,961	48.2	$ 297,958	3.4%	$ 3,562,006	$ 4,560,658	$ 4,622,261	29.28	$ 157,844	1.78%
Plant Daniel Unit #1											
311	Structures and Improvements	$ 8,591,584	63.1	$ 122,430	1.4%	$ 4,916,306	$ 6,294,652	$ 2,419,362	27.5	$ 87,977	1.02%
312	Boiler Plant Equipment	$ 52,849,104	42.2	$ 1,958,059	3.7%	$ 21,221,298	$ 27,170,948	$ 27,636,216	25.9	$ 1,068,678	2.02%
314	Turbogenerator Units	$ 19,983,679	41.0	$ 968,209	4.8%	$ 8,176,347	$ 10,468,685	$ 10,483,203	25.0	$ 419,328	2.10%
315	Accessory Electric Equipment	$ 10,401,463	52.0	$ 296,442	2.9%	$ 5,246,088	$ 6,716,893	$ 3,981,012	26.5	$ 150,227	1.44%
316	Misc. Power Plant Equipment	$ 12,158	39.0	$ 866	7.1%	$ 5,210	$ 6,670	$ 6,354	23.4	$ 272	2.23%
	Subtotal	$ 91,837,988	44.2	$ 3,346,007	3.6%	$ 39,565,248	$ 50,657,848	$ 44,526,147	25.79	$ 1,726,481	1.88%
Plant Daniel Unit #2											
311	Structures and Improvements	$ 9,478,035	60.6	$ 154,018	1.6%	$ 4,672,976	$ 5,983,102	$ 3,648,951	31.2	$ 116,954	1.23%
312	Boiler Plant Equipment	$ 62,892,747	45.0	$ 2,657,219	4.2%	$ 23,208,785	$ 29,715,651	$ 35,834,315	29.1	$ 1,232,810	1.96%
314	Turbogenerator Units	$ 24,457,004	44.0	$ 1,351,249	5.5%	$ 9,384,819	$ 12,015,968	$ 13,792,285	28.0	$ 492,582	2.01%
315	Accessory Electric Equipment	$ 10,953,732	53.4	$ 355,996	3.3%	$ 4,977,128	$ 6,372,526	$ 4,937,202	29.9	$ 165,124	1.51%
316	Misc. Power Plant Equipment	$ 559,888	28.1	$ 45,491	8.1%	$ 47,396	$ 60,684	$ 544,695	25.9	$ 21,031	3.76%
	Subtotal	$ 108,341,406	46.4	$ 4,563,973	4.2%	$ 42,291,104	$ 54,147,931	$ 58,757,448	28.97	$ 2,028,500	1.87%
		$ 260,872,215	46.5	$ 10,163,772	3.9%	$ 108,299,911	$ 138,663,112	$ 132,372,875	27.90	$ 4,743,712	1.82%
310	Daniel Common 1-2, Easements	$ 77,160	69.0	$ -	0.0%	$ 40,817	$ 41,511	$ 35,649	32.5	$ 1,097	1.42%
311	Daniel, Rail Track System	$ 2,782,273	66.4	$ -	0.0%	$ 1,420,468	$ 1,373,795	$ 1,408,478	32.5	$ 43,338	1.56%
Total Plant Daniel Depreciable		$ 263,731,648	46.7	$ 10,163,772	3.9%	$ 109,761,195	$ 140,078,418	$ 133,817,002	27.95	$ 4,788,147	1.82%
Plant Daniel Other Recovery/Non-Depreciable											
310	Land	$ 1,028,761					$ -				
310	Cooling Lake	$ 2,621,892					$ 2,621,892				
311	Cooling Lake	$ 6,331,377					$ 6,331,377				
316	Cooling Lake	$ 923					$ 923				
317	ARO	$ 391,150					$ 19,870,960				
	Dismantlement						$ 110,114				
TOTAL PLANT DANIEL		$ 274,105,751					$ 169,013,684				

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Account	Account Name	12/31/2013 Plant Balance	Average Service Life	IRR Net Removal Excl. Dismantling Amount	IRR Net Removal Excl. Dismantling Percent	Reserve Requirement w/ Net Removal	12/31/2013 Accumulated Depreciation Reserve	Amount to be Recovered	Average Remaining Life	Recommended Annual Depreciation	Depreciation Rate
		$	Yrs	$	%	$	$	$	Years	$	%
Plant Scherer Common A											
311	Structures and Improvements	$ 1,235,793	48.1	$ 6,542	0.5%	$ 297,024	$ 425,236	$ 817,098	36.6	$ 22,325	1.81%
312	Boiler Plant Equipment	$ 16,715,253	38.0	$ 230,065	1.4%	$ 1,925,217	$ 2,756,250	$ 14,189,067	33.7	$ 421,257	2.52%
314	Turbogenerator Units	$ 222,745	40.6	$ 4,009	1.8%	$ 46,915	$ 67,166	$ 159,588	32.2	$ 4,956	2.23%
315	Accessory Electric Equipment	$ 456,660	40.4	$ 4,835	1.1%	$ 63,970	$ 91,583	$ 369,912	34.8	$ 10,630	2.33%
316	Misc. Power Plant Equipment	$ -									
	Subtotal	$ 18,630,451	38.6	$ 245,451	1.3%	$ 2,333,125	$ 3,340,235	$ 15,535,667	33.83	$ 459,168	2.46%
Plant Scherer Common B											
311	Structures and Improvements	$ 11,293,552	62.3	$ 59,785	0.5%	$ 4,683,479	$ 6,705,137	$ 4,648,200	36.6	$ 127,000	1.12%
312	Boiler Plant Equipment	$ 21,225,807	40.1	$ 292,147	1.4%	$ 3,443,577	$ 4,930,022	$ 16,587,932	33.7	$ 492,476	2.32%
314	Turbogenerator Units	$ 1,255,314	62.6	$ 22,594	1.8%	$ 620,582	$ 888,460	$ 389,448	32.2	$ 12,095	0.96%
315	Accessory Electric Equipment	$ 423,964	60.8	$ 4,489	1.1%	$ 183,220	$ 262,308	$ 166,145	34.8	$ 4,774	1.13%
316	Misc. Power Plant Equipment	$ 5,249,100	47.5	$ 138,937	2.6%	$ 2,075,812	$ 2,971,851	$ 2,416,186	29.2	$ 82,746	1.58%
	Subtotal	$ 39,447,737	46.5	$ 517,952	1.3%	$ 11,006,670	$ 15,757,778	$ 24,207,910	33.66	$ 719,092	1.82%
Plant Scherer Unit #3											
311	Structures and Improvements	$ 20,590,821	61.6	$ 109,003	0.5%	$ 8,400,902	$ 12,027,213	$ 8,672,611	36.6	$ 236,957	1.15%
312	Boiler Plant Equipment	$ 240,286,487	40.3	$ 3,307,243	1.4%	$ 39,998,408	$ 57,264,009	$ 186,329,721	33.7	$ 5,531,914	2.30%
314	Turbogenerator Units	$ 39,516,176	53.2	$ 711,242	1.8%	$ 15,879,244	$ 22,733,634	$ 17,493,784	32.2	$ 543,285	1.37%
315	Accessory Electric Equipment	$ 9,763,934	54.9	$ 103,376	1.1%	$ 3,612,622	$ 5,172,036	$ 4,695,274	34.8	$ 134,922	1.38%
316	Misc. Power Plant Equipment	$ 1,385,524	45.1	$ 36,673	2.6%	$ 501,395	$ 717,826	$ 704,371	29.2	$ 24,122	1.74%
	Subtotal	$ 311,542,942	43.0	$ 4,267,536	1.4%	$ 68,392,571	$ 97,914,718	$ 217,895,761	33.67	$ 6,471,199	2.08%
Total Plant Scherer Depreciable		$ 369,621,130	43.1	$ 5,030,939	1.4%	$ 81,732,366	$ 117,012,731	$ 257,639,338	33.68	$ 7,649,459	2.07%
Plant Scherer Other Recovery/Non-Depreciable											
310	Land	986,244					$ -				
316	Amortization Property (7 yr.)	161,971					$ 91,483				
317	ARO	230,322					$ 67,907				
	Dismantlement						$ 5,143,641				
TOTAL PLANT SCHERER		$ 370,999,667					$ 122,315,762				
Total Depreciable Steam Excl. A/C 317		$ 2,321,416,874	30.7	$ 61,582,761	2.7%	$ 647,553,665	$ 695,156,356	$ 1,687,843,279	22.39	$ 75,391,537	3.25%

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Account	Account Name	12/31/2013 Plant Balance $	Average Service Life Yrs	IRR Net Removal Excl. Dismantling Amount $	IRR Net Removal Excl. Dismantling Percent %	Reserve Requirement w/ Net Removal $	12/31/2013 Accumulated Depreciation Reserve $	Amount to be Recovered $	Average Remaining Life Years	Recommended Annual Depreciation $	Depreciation Rate %
OTHER PRODUCTION PLANT											
Plant Smith CT											
341	Structures and Improvements	$ 1,310,239	16.7	$ 1,327	0.1%	$ 259,172	$ 149,582	$ 1,161,984	13.4	$ 86,715	6.62%
342	Fuel Holders	$ 697,862	21.2	$ 1,413	0.2%	$ 263,877	$ 209,481	$ 489,794	13.2	$ 37,106	5.32%
343	Prime Movers	$ 2,405,737	16.1	$ 4,872	0.2%	$ 434,209	$ 304,536	$ 2,106,073	13.2	$ 159,551	6.63%
344	Generators	$ 3,438,922	43.1	$ 5,803	0.2%	$ 2,381,736	$ 3,074,249	$ 370,476	13.3	$ 27,855	0.81%
345	Accessory Electric Equipment	$ 48,475	34.3	$ 82	0.2%	$ 29,729	$ 29,087	$ 19,470	13.3	$ 1,464	3.02%
346	Misc. Power Plant Equipment	$ 43,147	16.6	$ 87	0.2%	$ 8,855	$ (7,302)	$ 50,536	13.2	$ 3,829	8.87%
	Subtotal	$ 7,944,382	23.1	$ 13,584	0.2%	$ 3,377,578	$ 3,759,633	$ 4,198,333	13.26	$ 316,520	3.98%
Plant Smith CC											
341	Structures and Improvements	$ 13,847,570	33.6	$ 98,664	0.7%	$ 2,946,972	$ 878,718	$ 13,067,516	26.5	$ 493,114	3.56%
342	Fuel Holders	$ 3,585,547	34.4	$ 17,883	0.5%	$ 764,681	$ (532,194)	$ 4,135,624	27.1	$ 152,606	4.26%
343	Prime Movers	$ 116,898,041	27.1	$ 1,665,797	1.4%	$ 11,643,100	$ (8,563,463)	$ 127,127,301	24.4	$ 5,201,874	4.45%
344	Generators	$ 70,111,812	37.3	$ 349,683	0.5%	$ 19,268,291	$ 13,342,220	$ 57,119,275	27.1	$ 2,107,722	3.01%
345	Accessory Electric Equipment	$ 12,700,514	36.0	$ 72,393	0.6%	$ 3,228,707	$ 1,307,781	$ 11,465,126	26.9	$ 426,213	3.36%
346	Misc. Power Plant Equipment	$ 1,421,987	30.1	$ 15,197	1.1%	$ 219,636	$ (852,368)	$ 2,289,552	25.5	$ 89,786	6.31%
	Subtotal	$ 218,565,471	30.7	$ 2,219,617	1.0%	$ 38,071,388	$ 5,580,694	$ 215,204,394	25.40	$ 8,471,316	3.88%
Plant Pace CT											
341	Structures and Improvements	$ -					$ -				
342	Fuel Holders	$ -					$ -				
343	Prime Movers	$ 6,790,595	20.0	$ 4,584	0.1%	$ 5,266,263	$ 5,343,698	$ 1,451,481	4.5	$ 322,551	4.75%
344	Generators	$ 3,107,233	20.0	$ 1,748	0.1%	$ 2,409,460	$ 2,455,849	$ 653,132	4.5	$ 145,140	4.67%
345	Accessory Electric Equipment	$ 584,090	20.0	$ 329	0.1%	$ 452,924	$ 461,444	$ 122,975	4.5	$ 27,328	4.68%
346	Misc. Power Plant Equipment	$ -									
	Subtotal	$ 10,481,918	20.0	$ 6,660	0.1%	$ 8,128,648	$ 8,260,991	$ 2,227,587	4.50	$ 495,019	4.72%
Perdido Landfill Plant											
341	Structures and Improvements	$ 2,803,840	17.7	$ 3,470	0.1%	$ 222,047	$ 118,928	$ 2,688,382	16.3	$ 164,931	5.88%
342	Fuel Holders	$ 896,565	18.4	$ 2,219	0.2%	$ 112,348	$ 72,536	$ 826,248	16.1	$ 51,320	5.72%
343	Prime Movers	$ 4,561,649	18.3	$ 11,290	0.2%	$ 549,752	$ 344,295	$ 4,228,644	16.1	$ 262,649	5.76%
344	Generators	$ -					$ -				
345	Accessory Electric Equipment	$ 1,151,915	18.6	$ 2,376	0.2%	$ 148,941	$ 98,807	$ 1,055,484	16.2	$ 65,153	5.66%
346	Misc. Power Plant Equipment	$ 227,150	17.1	$ 562	0.2%	$ 13,317	$ 175,707	$ 52,005	16.1	$ 3,230	1.42%
	Subtotal	$ 9,641,119	18.1	$ 19,917	0.2%	$ 1,046,405	$ 810,273	$ 8,850,763	16.17	$ 547,283	5.68%
Total Depreciable Other Production		**$ 246,632,890**	**29.0**	**$ 2,259,778**	**0.9%**	**$ 50,624,018**	**$ 18,411,591**	**$ 230,481,077**	**23.45**	**$ 9,830,138**	**3.99%**
Total Depreciable Production		**$ 2,568,049,764**	**30.5**	**$ 63,842,539**	**2.5%**	**$ 698,177,683**	**$ 713,567,947**	**$ 1,918,324,356**	**22.61**	**$ 85,221,674**	**3.32%**
Company Proposed Depr. Production		$ 2,568,049,764		$ 107,508,936		$ 790,091,702	$ 713,567,947	$ 1,961,990,753		$ 91,086,749	
Difference		$ -		$ (43,666,397)		$ (91,914,019)	$ -	$ (43,666,397)		$ (5,865,075)	

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PROPOSED DEPRECIATION FACTORS AND RATES
AT DECEMBER 31, 2013

Account	Account Name	12/31/2013 Plant Balance	Average Service Life	IRR Net Removal Excl. Dismantling Amount	IRR Net Removal Excl. Dismantling Percent	Reserve Requirement w/ Net Removal	12/31/2013 Accumulated Depreciation Reserve	Amount to be Recovered	Average Remaining Life	Recommended Annual Depreciation	Depreciation Rate
		$	Yrs	$	%	$	$	$	Years	$	%
TRANSMISSION PLANT											
350.0	Easements	$ 13,166,131	90.0	$ -	0	$ 6,710,802		$ 6,455,329	56.1	$ 115,130	0.87%
								$ -			
352.0	Structures and Improvements	$ 10,584,304	55.0	$ 529,215	5%	$ 3,554,243		$ 7,559,276	40.2	$ 188,135	1.78%
353.0	Station Equipment	$ 148,680,261	48.0	$ 10,407,618	7%	$ 30,353,808		$ 128,734,071	41.4	$ 3,111,774	2.09%
354.0	Towers and Fixtures	$ 40,666,668	55.0	$ 8,133,333	20%	$ 25,694,763		$ 23,105,238	31.2	$ 740,078	1.82%
355.0	Poles and Fixtures	$ 126,998,316	40.0	$ 63,499,159	50%	$ 26,103,300		$ 164,394,175	33.2	$ 4,947,161	3.90%
356.0	Overhead Conductors and Devices	$ 110,339,741	55.0	$ 22,067,948	20%	$ 26,243,685		$ 106,164,004	46.5	$ 2,285,063	2.07%
358.0	Underground Conductors and Devices	$ 14,094,502	50.0	$ -	0%	$ 7,530,398		$ 6,564,104	26.3	$ 249,491	1.77%
359.0	Roads and Trails	$ 235,919	55.0	$ -	0%	$ 37,796		$ 198,123	45.0	$ 4,406	1.87%
Sub-Total Excluding Easements		$ 451,599,711	47.6	$ 104,637,273	23%	$ 119,517,993		$ 436,718,991		$ 11,526,107	
Sub-Total Including Easements		$ 464,765,842	48.2	$ 104,637,273	23%	$ 126,228,795		$ 443,174,320		$ 11,641,237	
350	Land	$ 4,782,914									
TOTAL TRANSMISSION PLANT		$ 469,548,756		$ 104,637,273		$ 126,228,795		$ 443,174,320		$ 11,641,237	
Company Proposed Transmission Plant										$ 12,690,336	
Difference										$ (1,049,099)	

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AT DECEMBER 31, 2013

Account	Account Name	12/31/2013 Plant Balance $	Average Service Life Yrs	IRR Net Removal Excl. Dismantling Amount $	IRR Net Removal Excl. Dismantling Percent %	Reserve Requirement w/ Net Removal $	12/31/2013 Accumulated Depreciation Reserve $	Amount to be Recovered $	Average Remaining Life Years	Recommended Annual Depreciation $	Depreciation Rate %
DISTRIBUTION PLANT											
360.2	Easements	$ 555,176	55.0	$ -	0%	$ 29,160		$ 526,016	52.2	$ 10,083	1.82%
361.0	Structures and Improvements	$ 20,429,669	52.0	$ 1,021,483	5%	$ 7,593,011		$ 13,858,141	36.5	$ 379,779	1.86%
362.0	Station Equipment	$ 239,656,818	46.0	$ 11,982,841	5%	$ 60,317,168		$ 191,322,491	36.2	$ 5,285,152	2.21%
364.0	Poles and Fixtures	$ 131,001,902	34.0	$ 91,701,330	70%	$ 68,016,181		$ 154,687,051	26.9	$ 5,754,727	4.39%
365.0	Overhead Conductors and Devices	$ 135,820,193	42.0	$ 33,955,048	25%	$ 49,189,082		$ 120,586,159	30.0	$ 4,014,186	2.96%
366.0	Underground Conduit	$ 1,160,719	60.0	$ -	0%	$ 793,560		$ 367,159	26.3	$ 13,960	1.20%
367.0	Underground Conductors and Devices	$ 141,302,574	39.0	$ 14,130,257	10%	$ 50,241,099		$ 105,191,732	29.8	$ 3,525,192	2.49%
368.0	Line Transformers	$ 247,768,588	34.0	$ 49,553,718	20%	$ 90,887,756		$ 208,434,550	26.3	$ 7,855,196	3.17%
369.1	Overhead Services	$ 53,372,992	44.0	$ 29,355,145	55%	$ 33,119,104		$ 49,609,033	31.0	$ 1,599,775	3.00%
369.2	Underground Services	$ 45,243,221	44.0	$ 4,524,322	10%	$ 16,563,038		$ 33,204,505	33.0	$ 1,006,807	2.23%
370.0	Meters	$ 20,142,321	33.0	$ (2,014,232)	-10%	$ 5,944,152		$ 12,183,937	23.0	$ 529,736	2.63%
370.1	Meters - AMI	$ 51,097,347	20.0	$ -	0%	$ 3,019,144		$ 48,078,203	17.3	$ 2,787,142	5.45%
	Meters - FPSC Segregated	$ 1,860,712	30.0	$ -	0%	$ 1,860,712		$ -	0.0	$ -	0.00%
	Meters - Non FPSC Segregated	$ 3,430,772	30.0	$ -	0%	$ 3,776,973		$ (346,201)	0.0	$ -	0.00%
373.0	Street Lighting and Signal Systems	$ 64,373,931	24.0	$ 9,656,090	15%	$ 32,627,557		$ 41,402,464	17.3	$ 2,395,976	3.72%
Sub-Total		$ 1,157,216,935	36.3	$ 243,866,002	21%	$ 423,977,697		$ 977,105,240		$ 35,157,712	
360	Land	$ 3,928,365									
TOTAL DISTRIBUTION PLANT		$ 1,161,145,300		$ 243,866,002		$ 423,977,697		$ 977,105,240		$ 35,157,712	
Company Proposed Distribution Plant										$ 40,247,006	
Difference										$ (5,089,294)	
GENERAL PLANT											
390.0	Structures and Improvements	$ 77,711,059	50.0	$ (7,771,106)	-10	$ 27,003,165		$ 42,936,788	36.1	$ 1,190,044	1.53%
396.0	Power Operated Equipment	$ 864,641	17.0	$ (172,928)	-20	$ 513,177		$ 178,536	6.8	$ 26,217	3.03%
397.0	Communications Equipment	$ 23,194,669	17.0	$ -	0	$ 11,822,212		$ 11,372,457	10.4	$ 1,094,558	4.72%
	Transportation Equipment										
392.2	Light Trucks	$ 7,120,679	11.0	$ (356,034)	-5	$ 3,363,803		$ 3,400,842	3.5	$ 985,751	13.84%
392.3	Heavy Trucks	$ 22,519,409	12.0	$ (3,377,911)	-15	$ 12,458,065		$ 6,683,433	4.3	$ 1,565,207	6.95%
392.4	Tailers	$ 1,269,865	20.0	$ (114,288)	-9	$ 634,261		$ 521,316	8.9	$ 58,575	4.61%
Total Transportation Equipment		$ 30,909,953	11.9	$ (3,848,233)	-12	$ 16,456,129		$ 10,605,591	4.1	$ 2,609,533	
TOTAL DEPRECIABLE GENERAL PLANT		$ 132,680,322		$ (11,792,267)		$ 55,794,683		$ 65,093,372		$ 4,920,352	
Company Proposed General Plant										$ 5,673,948	
Difference										$ (753,596)	

Docket Nos. 130140-EI, 130151-EI, 130092-EI
Exhibit ___ (JP-1)
Recommended Depreciation Adjustments Summary
Page 8 of 9

GULF POWER COMPANY
PROPOSED DEPRECIATION FACTORS AND RATES
AT DECEMBER 31, 2013

Account	Account Name	12/31/2013 Plant Balance $	Average Service Life Yrs	IRR Net Removal Excl. Dismantling Amount $	IRR Net Removal Excl. Dismantling Percent %	Reserve Requirement w/ Net Removal $	12/31/2013 Accumulated Depreciation Reserve $	Amount to be Recovered $	Average Remaining Life Years	Recommended Annual Depreciation $	Depreciation Rate %
GENERAL PLANT AMORTIZATION											
	Office Furniture & Equipment										
391.1	Furniture/Non-Computer	$ 2,463,098	7.0	$ -	0.0	$ 1,332,801		$ 1,130,297		$ 172,699	7.01%
391.2	Computer Equipment	$ 2,395,968	5.0	$ -	0.0	$ 2,054,272		$ 341,696		$ 1,034,767	43.19%
Total Office Furniture & Equipment		$ 4,859,066		$ -	0.0	$ 3,387,073		$ 1,471,993		$ 1,207,466	
	Auxiliary General Equipment										
392.5	Marine Equipment	$ 213,594	5.0	$ -	0.0	$ (21,324)		$ 234,918		$ 32,880	15.39%
393.0	Stores Equipment	$ 1,231,907	7.0	$ -	0.0	$ 152,426		$ 1,079,481		$ 73,314	5.95%
394.0	Tools, Shop & Garage Equipment	$ 4,075,785	7.0	$ -	0.0	$ 1,433,369		$ 2,642,416		$ 354,558	8.70%
395.0	Laboratory Equipment	$ 3,361,355	7.0	$ -	0.0	$ 1,672,165		$ 1,689,190		$ 324,632	9.66%
397.0	Communication Equip	$ 3,620,424	7.0	$ -	0.0	$ 1,173,223		$ 2,447,201		$ 459,701	12.70%
398.0	Miscellaneous Equipment	$ 3,572,092	7.0	$ -	0.0	$ (219,160)		$ 3,791,252		$ 1,185,033	33.17%
Total Auxiliary General Equipment		$ 16,075,157		$ -	0.0	$ 4,190,699		$ 11,649,540		$ 2,397,238	
Total Amortizable General Plant		$ 20,934,223				$ 7,577,772					
Total Depreciable & Amortizable General Plant		$ 153,614,545				$ 63,372,455					
NON-DEPRECIABLE GENERAL PROPERTY											
389.0	Land	$ 7,112,487									
		$ 7,112,487									
TOTAL GENERAL PLANT		$ 160,727,032				$ 63,372,455					
INTANGIBLE ASSET											
303.0	Intangible Software	$ 15,892,775	10.0	$ -	0.0	$ 6,143,733		$ 9,749,042		$ 1,329,862	8.37%
Company Proposed Intangible Asset										$ 2,270,396	
Difference										$ (940,534)	
	Dismantling									$ (6,288,508)	
Total Adjustments										$ (19,986,106)	

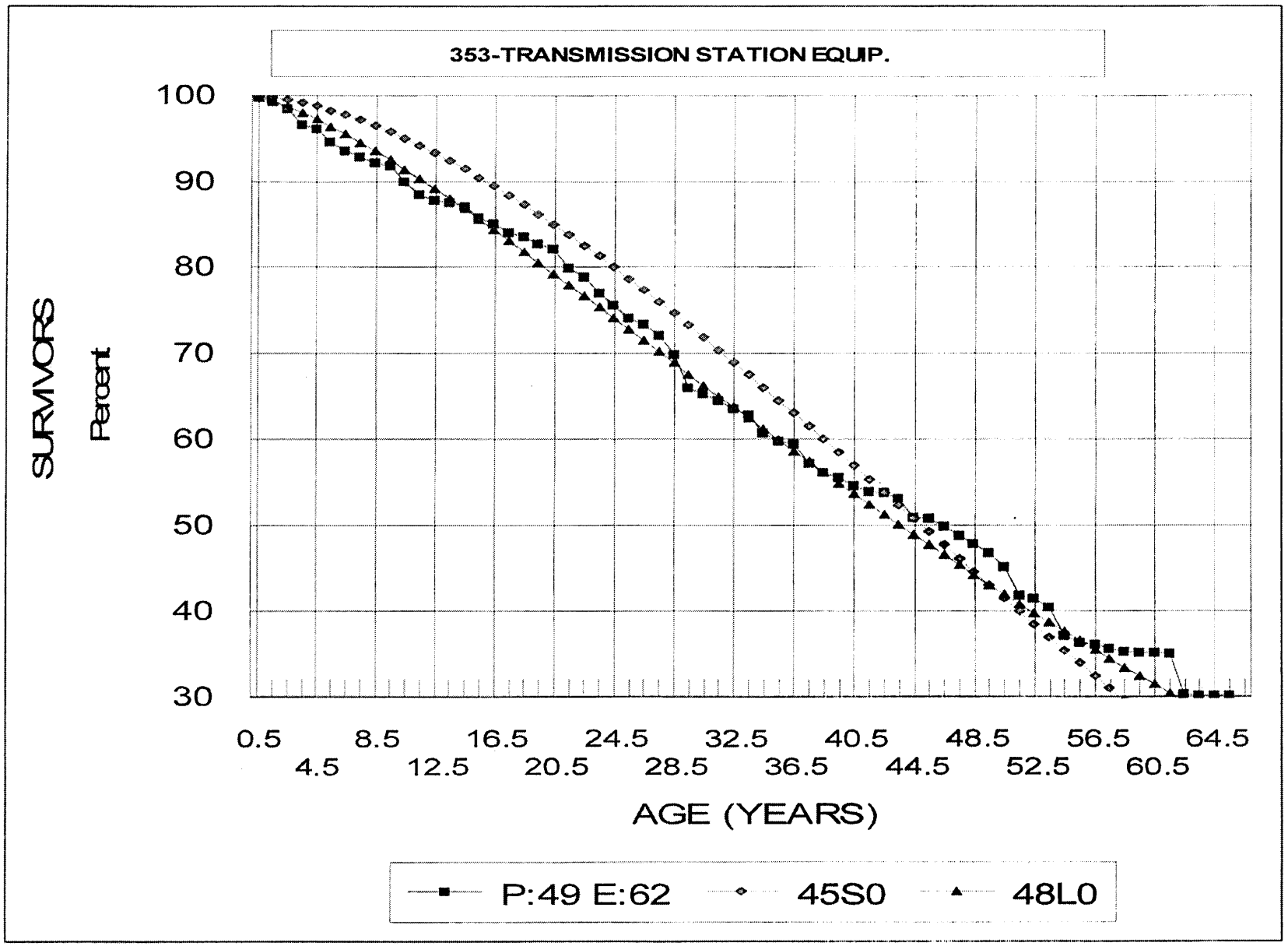
Docket Nos. 130140-EI, 130151-EI, 130092-EI
Exhibit ___ (JP-1)
Recommended Depreciation Adjustments Summary
Page 9 of 9

OFFICE OF PUBLIC COUNSEL'S RECOMMENDED
MASS PROPERTY LIFE ADJUSTMENTS
FOR GULF POWER COMPANY
BASED ON ESTIMATED PLANT AS OF 12/31/2013

Account	Gulf Existing	Gulf Proposed	OPC Proposed	OPC Adjustment	Impact
350.2 – Transmission Easements and Right-of-Ways	60SQ	65R5	90R5	25	$88,959
353 – Transmission Station Equipment	45S0	45S0	48L0	3	$443,434
356 – Transmission Overhead Conductors	50R2	50R1.5	53R0.5	3	$279,212
364 – Distribution Poles and Fixtures	34R1	32L0	34L0	2	$435,231
365 – Distribution Overhead Conductors	38R1	40L1	42R1	2	$275,610
367 – Distribution Underground Conductors and Devices	32S2	34S2	39R2	5	$854,147
368 – Distribution Line Transformers	30S0	32S0	34R0.5	2	$1,149,526
369.1 – Distribution Overhead Services	35R1	40R1	44R1	4	$227,445
370.1 – Distribution Meters – AMR	15R1	15R1	20R1	5	$1,137,609
373 – Distribution Street Lights	20L1	22L1	24L0.5	2	$433,994
390 – General Plant Structures and Improvements	45S1.5	45S1.5	50S0.5	5	$325,041
303 – Intangible Plant – Software	N/A	7SQ	10SQ	3	$940,539
Total					$6,587,747

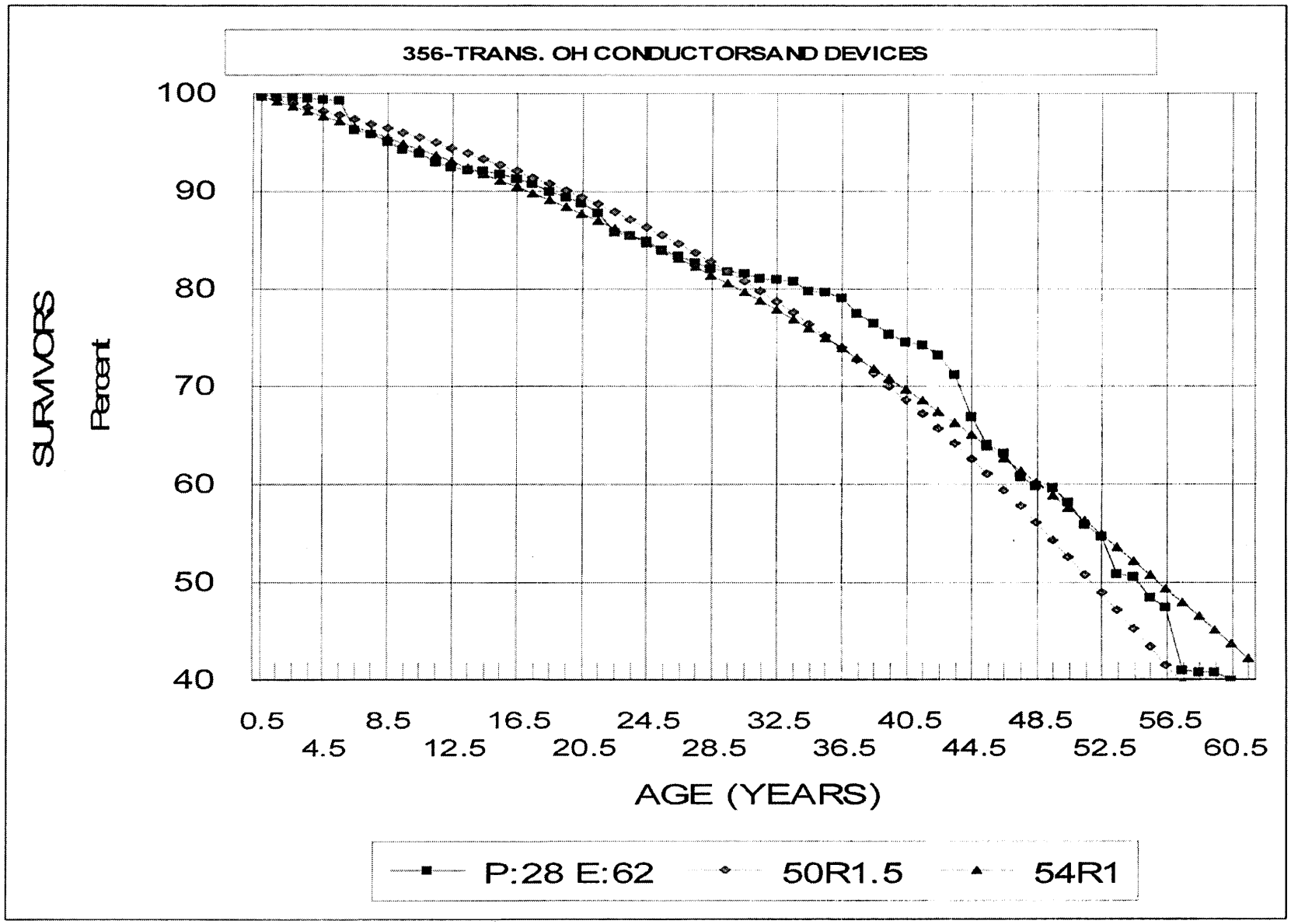
Docket Nos. 130140-EI, 130151-EI, 130092-EI
Exhibit (JP-2)
Mass Life Adjustment Summary
Page 1 of 1

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130140-EI EXHIBIT 38
PARTY Office of Public Counsel (OPC) Direct
DESCRIPTION Jacob Pous (JP-2)
DATE



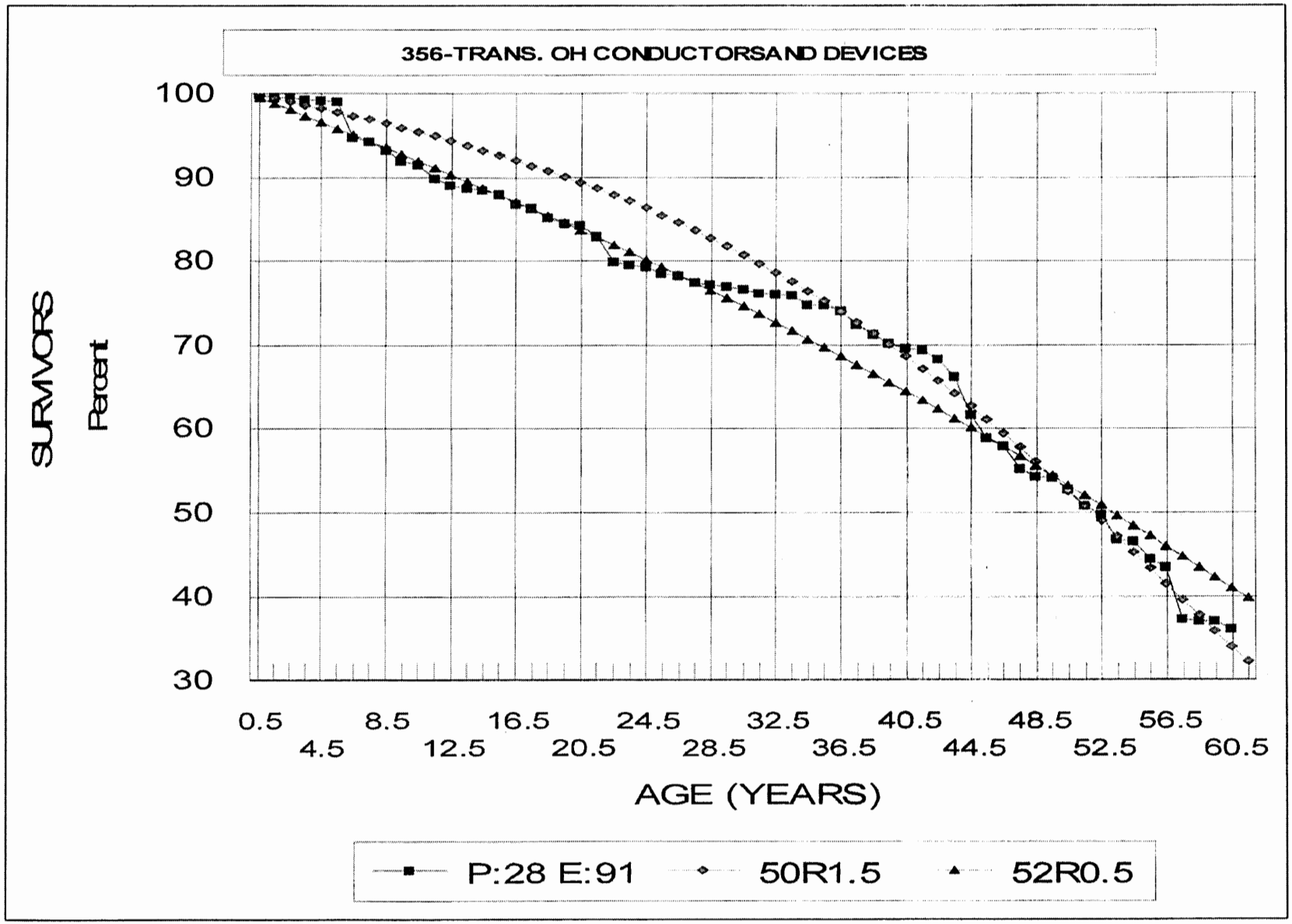
FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130140-EI EXHIBIT 39
PARTY Office of Public Counsel (OPC) Direct
DESCRIPTION Jacob Pous (JP-3)

Docket Nos. 130140-EI, 130151-EI, 130092-EI
Exhibit__(JP-3)
Life-Curve Combination for Account 353
Page 1 of 1



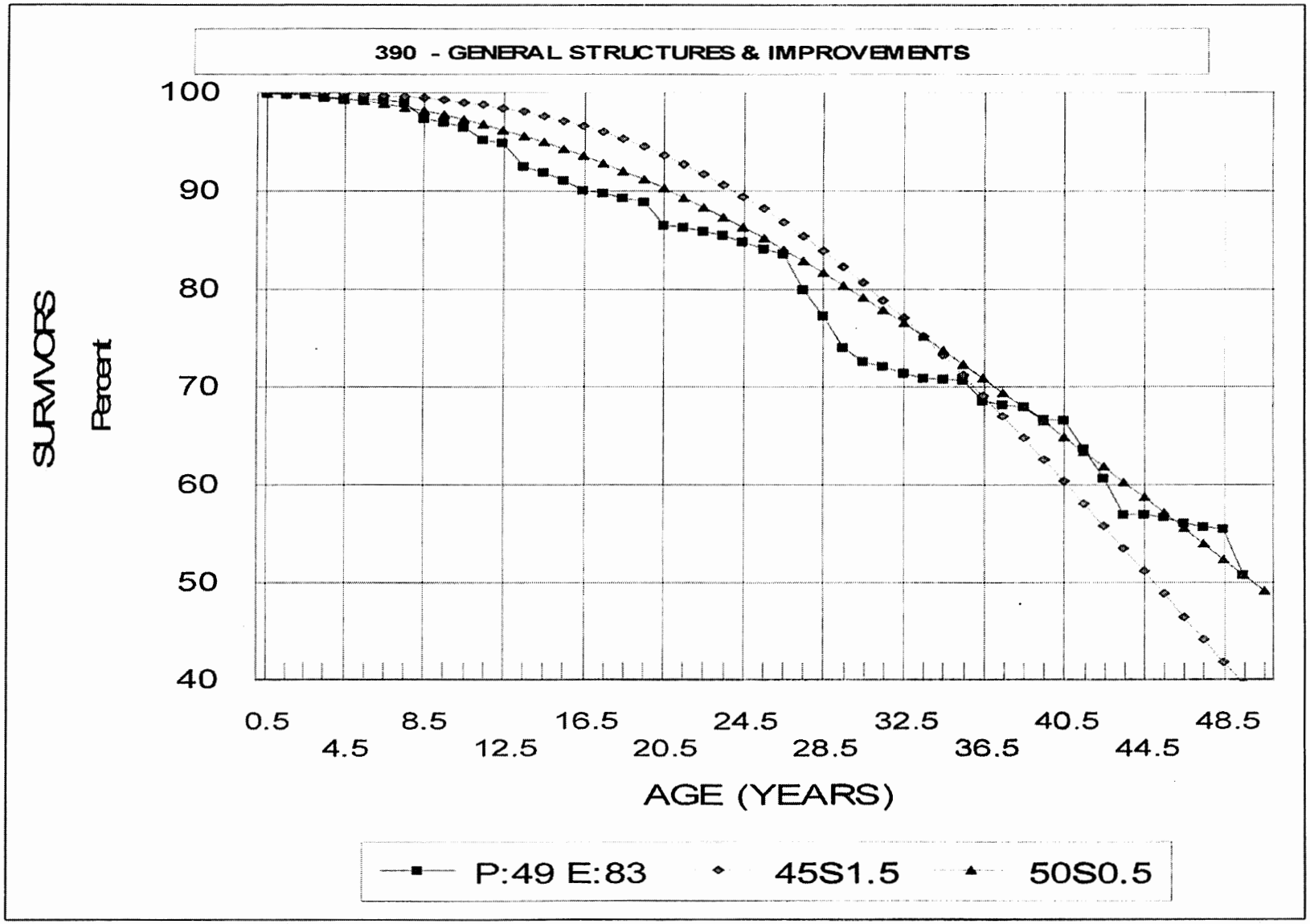
Docket Nos. 130140-EI, 130151-EI, 130092-EI
Exhibit___(JP-4)
Life-Curve Combination for Account 356 Full Band
Page 1 of 1

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130140-EI EXHIBIT 40
PARTY Office of Public Counsel (OPC) Direct
DESCRIPTION Jacob Pous (JP-4)
DATE



Docket Nos. 130140-EI, 130151-EI, 130092-EI
Exhibit ___ (JP-5)
Life-Curve Combination for Account 356 21-Year Band
Page 1 of 1

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130140-EI EXHIBIT 41
PARTY Office of Public Counsel (OPC) Direct
DESCRIPTION Jacob Pous (JP-5)



Docket Nos. 130140-EI, 130151-EI, 130092-EI
Exhibit___(JP-6)
Life-Curve Combination for Account 390
Page 1 of 1

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130140-EI EXHIBIT 42
PARTY Office of Public Counsel (OPC) Direct
DESCRIPTION Jacob Pous (JP-6)

OFFICE OF PUBLIC COUNSEL'S RECOMMENDED
AMORTIZATION OF ACCOUNT 303 INTANGIBLE SOFTWARE
FOR GULF POWER COMPANY
BASED ON ESTIMATED PLANT AS OF 12/31/2013

Year	Addition	Gulf Power Annual Amortization 2011	2012	2013	Total	Remaining Balance	Remaining Life 10SQ	Gulf Power Life 7SQ	OPC Adjustment
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
2010	$12,848,863	$1,835,552	$1,835,552	$1,835,552	$5,506,656	$7,342,207	$1,048,887	$1,835,552	$ (786,665)
2011	$1,831,497	$0	$261,642	$261,642	$523,285	$1,308,212	$163,527	$261,642	$ (98,116)
2012	$796,550	$0	$0	$113,793	$113,793	$682,757	$75,862	$113,793	$ (37,931)
2013	$415,865	$0	$0	$0	$0	$415,865	$41,587	$59,409	$ (17,823)
Total	$15,892,775	$1,835,552	$2,097,194	$2,210,987	$6,143,733	$9,749,042	$1,329,862	$2,270,396	$ (940,535)

SOURCES AND REFERENCES

Column (a): : 2013 Study Volumn 1 Tab 10 Plant Investment Activity 2009-2013 page 1 for each year.
Columns (b-d) : 2013 Study Volumn 1 Tab 11 Depreciation Reserve Activity 2009-2013 page 1 for each year.
Column (e) : Summation of Columns b-d.
Column (f) : Column (a) less Column (e).
Column (g) : Column (g) divided by 10.
Column (h) : Column (a) divided by 7.
Column (i) : Column (g) less Column (h).

Docket Nos. 130140-EI, 130151-EI, 130092-EI
Exhibit__(JP-7)
Calculation of Adjustment for Account 303
Page 1 of 1

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130140-EI EXHIBIT 43
PARTY Office of Public Counsel (OPC) Direct
DESCRIPTION Jacob Pous (JP-7)
DATE

JACOB POUS, P.E.

PRESIDENT, DIVERSIFIED UTILITY CONSULTANTS, INC.

B.S. INDUSTRIAL ENGINEERING, M.S. MANAGEMENT

I graduated from the University of Missouri in 1972, receiving a Bachelor of Science Degree in Engineering, and I graduated with a Master of Science in Management from Rollins College in 1980. I have also completed a series of depreciation programs sponsored by Western Michigan University, and have attended numerous other utility related seminars.

Since my graduation from college, I have been continuously employed in various aspects of the utility business. I started with Kansas City Power & Light Company, working in the Rate Department, Corporate Planning and Economic Controls Department, and for a short time in a power plant. My responsibilities included preparation of testimony and exhibits for retail and wholesale rate cases. I participated in cost of service studies, a loss of load probability study, fixed charge analysis, and economic comparison studies. I was also a principal member of project teams that wrote, installed, maintained, and operated both a computerized series of depreciation programs and a computerized financial corporate model.

I joined the firm of R. W. Beck and Associates, an international consulting engineering firm with over 500 employees performing predominantly utility related work, in 1976 as an Engineer in the Rate Department of its Southeastern Regional Office. While employed with that firm, I prepared and presented rate studies for various electric, gas, water, and sewer systems, prepared and assisted in the preparation of cost of service studies, prepared depreciation and decommissioning analyses for wholesale and retail rate proceedings, and assisted in the development of power supply studies for electric systems. I resigned from that firm in November 1986 in order to co-found Diversified Utility Consultants, Inc. At the time of my resignation, I held the titles of Executive Engineer, Associate and Supervisor of Rates in the Austin office of R. W. Beck and Associates.

As a principal of the firm of Diversified Utility Consultants, Inc., I have presented and prepared numerous electric, gas, and water analyses in both retail and wholesale proceedings. These analyses have been performed on behalf of clients, including public utility commissions, throughout the United States and Canada.

I have been involved in over 400 different utility rate proceedings, many of which have resulted in settlements prior to the presentation of testimony before regulatory bodies. I am registered to practice as a Professional Engineer in many states.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130140-EI EXHIBIT 44
PARTY Office of Public Counsel (OPC) Direct
DESCRIPTION Jacob Pous (JP-8)
DATE

UTILITY RATE PROCEEDINGS IN WHICH TESTIMONY HAS BEEN PRESENTED BY JACOB POUS

ALASKA		
ALASKA REGULATORY COMMISSION		
JURISDICTION / COMPANY	DOCKET NO.	TESTIMONY TOPIC
Beluga Pipe Line Company	P-04-81	Refundable Rates
Beluga Pipe Line Company	U-07-141	Depreciation
Kenai Nikiski Pipeline	U-04-81	Rate Base
ARIZONA		
ARIZONA CORPORATION COMMISSION		
JURISDICTION / COMPANY	DOCKET NO.	TESTIMONY TOPIC
Citizens Utilities Company	E-1032-93-111	Depreciation
ARKANSAS		
ARKANSAS PUBLIC SERVICE COMMISSION		
JURISDICTION / COMPANY	DOCKET NO.	TESTIMONY TOPIC
Reliant Energy ARKLA	01-0243-U	Depreciation
CALIFORNIA		
CALIFORNIA PUBLIC SERVICE COMMISSION		
JURISDICTION / COMPANY	DOCKET NO.	TESTIMONY TOPIC
Pacific Gas & Electric Company	App. No. 97-12-020	Depreciation, Net Salvage, and Amortization of True-Up
Pacific Gas & Electric Company	App. No. 02-11-017	Mass Property Salvage, Net Salvage, Mass Property Life, Life Analysis, Remaining Life, Depreciation
Pacific Gas & Electric Company	App. No. 12-11-009	Depreciation, Mass Property Net Salvage, Mass Property Life, Hydroelectric
San Diego Gas & Electric Company		Value of Power Plants
Southern California Edison Company	App 02-05-004	Depreciation, Net Salvage
Southern California Edison Company	App 10-11-015	Mass Property Life and Net Salvage
Southern California Gas & San Diego Gas & Electric Company	Apps 10-12-005 & 10-12-006	Mass Property Life, Mass Property Net Salvage
CANADA		
ALBERTA ENERGY AND UTILITIES BOARD		
JURISDICTION / COMPANY	DOCKET NO.	TESTIMONY TOPIC
AltaLink Management/ Transalta Utilities Corporation	App. Nos. 1279345 and 1279347	Depreciation
Epcor Distribution, Inc.	App. No. 1306821	Depreciation
Enmax Corporation	App. No. 1306818	Depreciation
Transalta Utilities Corporation	TFO Tariff App. 1287507	Depreciation
UtiliCorp Networks Canada (Alberta) Ltd.	App. No. 1250392	Depreciation
Atco Electric	App. No. 1275494	Depreciation

ALBERTA PUBLIC UTILITIES BOARD		
JURISDICTION / COMPANY	DOCKET NO.	TESTIMONY TOPIC
Alberta Power Limited	E 91095	Depreciation
Alberta Power Limited	E 97065	Depreciation
Canadian Western Natural Gas Company, Ltd.		Depreciation
Centra Gas Alberta, Inc.		Depreciation
Edmonton Power Company	E 97065	Depreciation
Edmonton Power Generation, Inc.	1999/2000	GUR Compliance, Depreciation
Northwestern Utilities, Ltd	E 91044	Depreciation
NOVA Gas Transmission, Ltd.	RE95006	Depreciation
TransAlta Utilities Corporation	E 91093	Depreciation
TransAlta Utilities Corporation	E 97065	Depreciation
TransAlta Utilities Corporation	App. No. 200051	Gain on Sale
ALBERTA UTILITIES COMMISSION		
JURISDICTION / COMPANY	DOCKET NO.	TESTIMONY TOPIC
AltaGas Utilities	1606694	Life Analysis, Net Salvage
AltaLink Management, Ltd.	1606895	Life Analysis, Net Salvage
AltaLink Management, Ltd.	1608711	Life Analysis, Net Salvage
ATCO Gas	1606822	Life Analysis, Net Salvage
FortisAlberta	1607159	Life Analysis, Net Salvage
NEWFOUNDLAND AND LABRADOR BOARD OF COMMISSIONERS OF PUBLIC UTILITIES		
Newfoundland & Labrador Hydro		Depreciation, Life Analysis
Newfoundland Power, Inc.	2013/2014 GRA	Depreciation, Life Analysis, Net Salvage, ELG vs. ALG
NORTHWEST TERRITORIES PUBLIC UTILITIES BOARD		
JURISDICTION / COMPANY	DOCKET NO.	TESTIMONY TOPIC
Northwest Territories Power Corporation	1995/96 and 1996-97	Depreciation
Northwest Territories Power Corporation	2001	Depreciation
NOVA SCOTIA UTILITY AND REVIEW BOARD		
JURISDICTION / COMPANY	DOCKET NO.	TESTIMONY TOPIC
Nova Scotia Power, Inc.	M03665	Production Plant Life and Net Salvage (Inflation), Interim Retirements, Mass Property Life and Net Salvage, ELG vs. ALG, Remaining Life, Fully Accrued
CONNECTICUT		
CONNECTICUT PUBLIC UTILITIES REGULATORY AUTHORITY		
JURISDICTION / COMPANY	DOCKET NO.	TESTIMONY TOPIC
Connecticut Natural Gas Co.	13-06-08	Depreciation, Life, Net Salvage
COURTS		
JURISDICTION / COMPANY	DOCKET NO.	TESTIMONY TOPIC
7th Judicial Circuit Court of Florida	2008-30441-CICI	Depreciation Valuation
112th Judicial District Court of Texas	5093	Ratemaking Principles, Calculation of damages
253rd Judicial District Court of Texas	45,615	Ratemaking Principles, Level of Bond
126th Judicial District Court of Texas	91-1519	Ratemaking Principles, Level of Bond

172 Judicial District Court of Texas		Franchise Fees
United States Bankruptcy Court Eastern District of Texas	93-10408S	Level of Harm, Ratemaking, Equity for Creditors
3rd Judicial District Court of Texas		Adequacy of Notice
DISTRICT OF COLUMBIA		
PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA		
JURISDICTION / COMPANY	DOCKET NO.	TESTIMONY TOPIC
Washington Gas Light Company	768	Depreciation
FLORIDA		
FLORIDA PUBLIC SERVICE COMMISSION		
JURISDICTION / COMPANY	DOCKET NO.	TESTIMONY TOPIC
Progress Energy Florida, Inc.	090079-EI	Depreciation, Excess Reserve
Progress Energy Florida, Inc.	050078-EL	Depreciation, Excess Reserve
Florida Power & Light Company	790380-EU	Territorial Dispute
Florida Power & Light Company	080677-EI 090130-EI	Depreciation, Excess Reserve
Florida Power & Light Company	120015-EI	Excess Reserve
Florida Power & Light Company	120015-EI	Settlement Analysis
Tampa Electric Co.	13-0040-EI	Depreciation, Amortization
FEDERAL ENERGY REGULATORY COMMISSION		
JURISDICTION / COMPANY	DOCKET NO.	TESTIMONY TOPIC
Alabama Power Company	ER83-369	Depreciation
Connecticut Municipal Electric Energy Cooperative v. Connecticut Light & Power Company	EL83-14	Decommissioning
Florida Power & Light Company	ER84-379	Depreciation, Decommissioning
Florida Power & Light Company	ER93-327-000	Transmission Access
Georgia Power Company	ER76-587	Rate Base
Georgia Power Company	ER79-88	Depreciation
Georgia Power Company	ER81-730	Coal Fuel Stock Inventory, Depreciation
ISO New England, Inc.	ER07-166-000	Depreciation
Maine Yankee Atomic Power Company	ER84-344-001	Depreciation, Decommissioning
Maine Yankee Atomic Power Company	ER88-202	Decommissioning
Pacific Gas & Electric	ER80-214	Depreciation
Public Service of Indiana	ER95-625-000, ER95-626-000 & ER95-039-000	Depreciation, Dismantlement
Southern California Edison Company	ER81-177	Depreciation
Southern California Edison Company	ER82-427	Depreciation, Decommissioning
Southern California Edison Company	ER84-75	Depreciation, Decommissioning
Southwestern Public Service Company	EL 89-50	Depreciation, Decommissioning
System Energy Resource, Inc.	ER95-1042-000	Depreciation, Decommissioning
Vermont Electric Power Company	ER83 342000 & 343000	Decommissioning
Virginia Electric and Power Company	ER78-522	Depreciation, Rate Base

INDIANA		
INDIANA UTILITY REGULATORY COMMISSION		
JURISDICTION / COMPANY	DOCKET NO.	TESTIMONY TOPIC
Indianapolis Water Company	39128	Depreciation
Indiana Michigan Power Company	39314	Depreciation, Decommissioning
KANSAS		
KANSAS CORPORATION COMMISSION		
JURISDICTION / COMPANY	DOCKET NO.	TESTIMONY TOPIC
Arkansas Louisiana Gas Company	181,200-U	Depreciation
United Cities Gas Company	181,940-U	Depreciation
LOUISIANA		
LOUISIANA PUBLIC SERVICE COMMISSION		
JURISDICTION / COMPANY	DOCKET NO.	TESTIMONY TOPIC
Louisiana Power & Light Company	U-16945	Nuclear Prudence, Depreciation
CITY OF NEW ORLEANS		
JURISDICTION / COMPANY	DOCKET NO.	TESTIMONY TOPIC
Entergy New Orleans, Inc.	UD-00-2	Rate Base, Depreciation
MASSACHUSETTS		
MASSACHUSETTS TELECOMMUNICATION AND ENERGY		
JURISDICTION / COMPANY	DOCKET NO.	TESTIMONY TOPIC
Bay State Gas	D.T.E.-0527	Depreciation
National Grid/KeySpan	07-30	Quality of Service
MISSISSIPPI		
MISSISSIPPI PUBLIC SERVICE COMMISSION		
JURISDICTION / COMPANY	DOCKET NO.	TESTIMONY TOPIC
Mississippi Power Company	U-3739	Cost of Service, Rate Base, Depreciation
MONTANA		
MONTANA PUBLIC SERVICE COMMISSION		
JURISDICTION / COMPANY	DOCKET NO.	TESTIMONY TOPIC
Montana Power Company (Gas)	90.6.39	Depreciation
Montana Power Company (Electric)	90.3.17	Depreciation, Decommissioning
Montana Power Company (Electric and Gas)	95.9.128	Depreciation
Montana-Dakota Utilities	D2007.7.79	Depreciation
Montana-Dakota Utilities	D2010.8.82	Depreciation, Interim Retirements, Production Plant Life and Net Salvage
Montana-Dakota Utilities	D2012.9.100	Depreciation
NEVADA		
PUBLIC UTILITIES COMMISSION OF NEVADA		
JURISDICTION / COMPANY	DOCKET NO.	TESTIMONY TOPIC
Nevada Power Company	81-602, 81-685 Cons.	Depreciation
Nevada Power Company	83-667, Consolidated	Depreciation
Nevada Power Company	91-5032	Depreciation, Decommissioning
Nevada Power Company	03-10002	Depreciation
Nevada Power Company	08-12002	Depreciation, CWC

Nevada Power Company	06-06051	Depreciation, Life Spans, Decommissioning Costs, Deferred Accounting
Nevada Power Company	06-11022	General Rate Case
Nevada Power Company	10-02009	Production Life Spans
Nevada Power Company	11-06007	Early Retirement, Production Plant Net Salvage, Mass Property Life, Mass Property Net Salvage, Excess APFD
Sierra Pacific Gas Company	06-07010	Depreciation, Generating Plant Life Spans, Decommissioning Costs, Carrying Costs
Sierra Pacific Power Company	83-955	Depreciation (Electric, Gas, Water, Common)
Sierra Pacific Power Company	86-557	Depreciation, Decommissioning
Sierra Pacific Power Company	89-516, 517, 518	Depreciation, Decommissioning (Electric, Gas, Water, Common)
Sierra Pacific Power Company	91-7079, 80, 81	Depreciation, Decommissioning (Electric, Gas, Water, Common)
Sierra Pacific Power Company	03-12002	Allowable Level of Plant in Service
Sierra Pacific Power Company	05-10004	Depreciation
Sierra Pacific Power Company	05-10006	Depreciation
Sierra Pacific Power Company	07-12001	Depreciation, CWC
Sierra Pacific Power Company	10-06003	Depreciation, Excess Reserve, Life Spans, Net Salvage
Sierra Pacific Power Company	10-06004	Depreciation, Net Salvage
Sierra Pacific Power Company	12-08009	IRP-Coal Plant Service Life
Sierra Pacific Power Company	13-06004	Depreciation, Life, Net Salvage
Southwest Gas Corporation	93-3025 & 93-3005	Depreciation
Southwest Gas Corporation	04-3011	Depreciation
Southwest Gas Corporation	07-09030	Depreciation
Southwest Gas Corporation	12-04005	Depreciation
NORTH CAROLINA		
NORTH CAROLINA UTILITIES COMMISSION		
JURISDICTION / COMPANY	DOCKET NO.	TESTIMONY TOPIC
North Carolina Natural Gas	G-21, Sub 177	Cost of Service, Rate Design, Depreciation
OKLAHOMA		
OKLAHOMA CORPORATION COMMISSION		
JURISDICTION / COMPANY	DOCKET NO.	TESTIMONY TOPIC
Arkansas Oklahoma Gas Corporation	PUD 200300088	CWC, Legal Expenses, Factoring, Cost Allocation, Depreciation
Oklahoma Natural Gas Company	PUD 980000683	Depreciation, Calculation Procedure, Depreciation on CWIP
Reliant Energy ARKLA	PUD 200200166	Depreciation, Net Salvage, Software Amortization
Public Service Company of Oklahoma	PUD 960000214	Depreciation, Interim Activity, Net Salvage, Mass Property, Rate Calculation Technique

Public Service Company of Oklahoma	PUD 200600285	Depreciation
Public Service Company of Oklahoma	PUD 200800144	Depreciation
Public Service Company of Oklahoma	PUD 201000050	Depreciation, Evaluation vs. Measurement, Interim and Terminal Net Salvage, Economies of Scale
Oklahoma Gas & Electric	PUD 201100087	Depreciation
SOUTH DAKOTA		
PUBLIC UTILITY COMMISSION OF THE STATE OF SOUTH DAKOTA		
JURISDICTION / COMPANY	DOCKET NO.	TESTIMONY TOPIC
Montana-Dakota Utilities	NG12-008	Depreciation, Life, Net Salvage
TEXAS		
PUBLIC UTILITY COMMISSION OF TEXAS		
JURISDICTION / COMPANY	DOCKET NO.	TESTIMONY TOPIC
CenterPoint Energy Houston Electric, LLC	29526	Stranded Costs
CenterPoint Energy Houston Electric, LLC	36918	Hurricane Cost Recovery
CenterPoint Energy Houston Electric, LLC	38339	Depreciation, Net Salvage, Excess Reserve, Gain on Sale
Central Power & Light Company	6375	Depreciation, Rate Base, Cost of Service
Central Power & Light Company	8439	Fuel Factor
Central Power & Light Company	8646	Rate Base, Excess Capacity, Depreciation, Rate Design, Rate Case Expense
Central Power & Light Company	9561	Depreciation, Excess Capacity, Cost of Service, Rate Base, Taxes
Central Power & Light Company	11371	Economic Development Rate
Central Power & Light Company	12820	Nuclear Fuel and Process, OPEB, Pension, Factoring, Depreciation
Central Power & Light Company	14965	Depreciation, Cash Working Capital, Pension, OPEB, Factoring, Demonstration and Selling Expense, Non-Nuclear Decommissioning
Central Power & Light Company	22352	Depreciation
Central Telephone & United Telephone Company of Texas d/b/a Sprint	17809	Rate Case Expenses
City of Fredericksburg	7661	Territorial Dispute
El Paso Electric Company	9165	Depreciation
Entergy Gulf States, Inc.	16705	Depreciation, Prepayments, Payroll Expense, Pension Expense, OPEB, CWC, Transfer of T&D Depreciation
Entergy Gulf States, Inc.	21111	Reconcilable Fuel Costs
Entergy Gulf States, Inc.	21384	Fuel Surcharge
Entergy Gulf States, Inc.	23000	Fuel Surcharge
Entergy Gulf States, Inc.	22356	Unbundling, Competition, Cost of Service
Entergy Gulf States, Inc.	23550	Reconcilable Fuel Costs
Entergy Gulf States, Inc.	24336	Price to Beat

Entergy Gulf States, Inc.	24460	Implement PUC Subst.R.25.41(f)(3)(D)
Entergy Gulf States, Inc.	24469	Delay of Deregulation
Entergy Gulf States, Inc.	24953	Interim Fuel Surcharge
Entergy Gulf States, Inc.	26612	Fuel Surcharge
Entergy Gulf States, Inc.	28504	Interim Fuel Surcharge
Entergy Gulf States, Inc.	28818	Cert. for Independent Organization
Entergy Gulf States, Inc.	29408	Fuel Reconciliation
Entergy Gulf States, Inc.	30163	Interim Fuel Surcharge
Entergy Gulf States, Inc.	31315	Incremental Purchase Capacity Rider
Entergy Gulf States, Inc.	31544	Transition to Competition Cost
Entergy Gulf States, Inc.	32465	Interim Fuel Surcharge
Entergy Gulf States, Inc.	32710	River Bend 30%, Explicit Capacity, Imputed Capacity, IPCR, SGSF Operating Costs and Depreciation Recovery, Option Costs
Entergy Gulf States, Inc.	33687	Transition to Competition
Entergy Gulf States, Inc.	33966	Interim Fuel Surcharge
Entergy Gulf States, Inc.	32907	Hurricane Reconstruction
Entergy Gulf States, Inc.	34724	IPCR
Entergy Gulf States, Inc.	34800	JSP, Depreciation, Decommissioning, Amortization, CWC, Franchise Fees, Rate Case Exp.
Entergy Texas Inc.	37744	Depreciation, Property Insurance Reserve, Cash Working Capital, Decommissioning Funding, Gas Storage
Entergy Texas Inc.	39896	Depreciation, Amortization, Property Insurance Reserve, Cash Working Capital
Gulf States Utilities Company	5560	Depreciation, Fuel Cost Factor
Gulf States Utilities Company	5820	Fuel Cost, Capacity Factors, Heat Rates
Gulf States Utilities Company	6525	Depreciation, Rate Case Expenses
Gulf States Utilities Company	7195 & 6755	Depreciation, Interim Cash Study, Excess Capacity, Rate Case Expense
Gulf States Utilities Company	8702	Rate Case Expenses, Depreciation
Gulf States Utilities Company	10,894	Fuel Reconciliation, Rate Case Expenses
Gulf States Utilities Company & Entergy Corporation	11292	Acquisition Adjustment Regulatory Plan, Base Rate, Rate Case Expenses
Gulf States Utilities Company & Entergy Corporation	12423	North Star Steel Agreement
Gulf States Utilities Company & Entergy Corporation	12852	Depreciation, OPEB, Pensions, Cash Working Capital, Other Cost of Service, and Rate Base Items
Houston Light & Power Company	6765	Depreciation, Production Plant, Early Retirement
Lower Colorado River Authority	8400	Rate Design
Magic Valley Electric Cooperative, Inc.	10820	Cost of Service, Financial Integrity, Rate Case Expenses

Oncor Electric Delivery, LLC	35717	Depreciation, Self-Insurance, Payroll, Automated Meters, Regulatory Assets, PHFU
Southwestern Bell Telephone Company	18513	Rate Case Expenses
Southwestern Electric Power Company	3716	Depreciation
Southwestern Electric Power Company	4628	Depreciation
Southwestern Electric Power Company	5301	Depreciation, Fuel Charges, Franchise Fees
Southwestern Electric Power Company	24449	Fuel Factor Component of Price to Beat Rates
Southwestern Electric Power Company	24468	Delay of Deregulation
Southwestern Public Service Company	11520	Depreciation, Cash Working Capital, Rate Case Expenses
Southwestern Public Service Company	32766	Depreciation Expense Revenue Requirements
Southwestern Public Service Company	35763	Depreciation
Texas-New Mexico Power Company	9491	Avoided Cost, Rate Case Expenses
Texas-New Mexico Power Company	10200	Jurisdictional Separation, Cost Allocation, Rate Case Expenses
Texas-New Mexico Power Company	17751	Rate Case Expenses
Texas-New Mexico Power Company	36025	Depreciation
Texas-New Mexico Power Company	38480	Depreciation, Mass Property Life, Net Salvage
Texas Utilities Electric Company	5640	Franchise Fees
Texas Utilities Electric Company	9300	Depreciation, Rate Base, Cost of Service, Fuel Charges, Rate Case Expenses
Texas Utilities Electric Company	11735	Cost Allocation, Rate Design, Rate Case Expenses
Texas Utilities Electric Company	18490	Depreciation Reclassification
West Texas Utilities Company	7510	Depreciation, Decommissioning, Rate Base, Cost of Service, Rate Design, Rate Case Expenses
West Texas Utilities Company	10035	Fuel Reconciliation, Rate Case Expenses
West Texas Utilities Company	13369	Depreciation, Payroll, Pension, OPEB, Cash Working Capital, Fuel Inventory, Cost Allocation
West Texas Utilities Company	22354	Depreciation
RAILROAD COMMISSION OF TEXAS		
JURISDICTION / COMPANY	DOCKET NO.	TESTIMONY TOPIC
Atmos Energy Corporation	9530	Gas Cost, Gas Purchases, Price Mitigation, Rate Case Expense
Atmos Energy Corporation	9670	CWC, Depreciation, Expenses, Shared Services, Taxes Other Than FIT, Excess Return
Atmos Energy Corporation	9695	Rate Case Expense
Atmos Energy Corporation	9762	Depreciation, O&M Expense
Atmos Energy Corporation	9732	Rate Case Expense
Atmos Energy Corporation	9869	Revenue Requirements

Atmos Energy Corporation	10041	Mass Property Life, Net Salvage
Atmos Energy Corporation	10170	Depreciation, Mass Property Life, Net Salvage
Atmos Pipeline-Texas	10000	Rate Base, Depreciation Life and Net Salvage, Incentive Compensation, Merit Increase, Outside Director Retirement Costs, SEBP
CenterPoint Energy Entex – City of Tyler	9364	Capital Investment, Affiliates
CenterPoint Energy Entex – Gulf Coast Division	9791	Rate Base, Cost Allocation, Affiliate Expenses, Depreciation Net Salvage, Call Center, Litigation, Uncollectibles, Post Test Year Adjustments
CenterPoint Energy Entex – City of Houston	9902	CWC, Plant Adjustments, Depreciation, Payroll, Pensions, Cost Allocation
CenterPoint Energy Entex – South Texas Division	10038	CWC, Incentive Compensation, Payroll, Depreciation
CenterPoint Energy – Beaumont/East Texas	10182	Rate Base, Expense, Incentive Compensation, Pension, Payroll, Injuries & Damages
CenterPoint Energy – Texas Coast Division	10007	Cost of Service Adjustment, CWC, ADIT, Incentive Compensation, Pension, Meter Reading, Customer Records and Collection, Investor Relations/Investor Services
CenterPoint Energy – Texas Coast Division	10097	Pension, Severance Expense
Energas Company	5793	Depreciation
Energas Company v. Westar Transmissions Company	5168 & 4892 Cons.	Cost of Service, Refunds, Contracts, Depreciation
Energas Company	8205	Cost of Service, Rate Base, Depreciation, Affiliate Transactions, Sale/Leaseback, Losses, Income Taxes
Energas Company	9002-9135	Depreciation, Pension, Cash Working Capital, OPEB, Rate Design
Lone Star Gas Company	8664	Cash Working Capital, Depreciation Expense, Gain on Sale of Plant, OPEB, Rate Case Expenses
Rio Grande Valley Gas Company	7604	Depreciation
Southern Union Gas Company	2738, 2958, 3002, 3018, 3019 Cons.	Cost of Service, Rate Design, Depreciation
Southern Union Gas Company	6968 Interim & Cons.	Affiliate Transactions, Rate Base, Income Taxes, Revenues, Cost of Service, Conservation, Depreciation
Southern Union Gas Company	8033 Consolidated	Acquisition Adjustment, Depreciation, Excess Reserve, Distribution Plant, Cost of Gas Clause, Rate Case Expenses

Southern Union Gas Company	8878	Depreciation, Cash Working Capital, Gain on Sale of Building, Rate Case Expenses, Rate Design
Texas Gas Service Company	9988 & 9992 Cons.	Cash Working Capital, Post Test Year Plant, ADFIT, Excess Reserve, Depreciation Expense, Amortization of General Plant, Corporate and Division Expenses, Incentive Compensation, Hotel and Meals Expense, Pipeline Integrity Costs
TXU Gas Distribution	9145-9147	Depreciation, Cash Working Capital, Revenues, Gain on Sale of Assets, Clearing Accounts, Over-Recovery of Clearing Accounts, SFAS 106, Wages and Salaries, Merger Costs, Intra System Allocation, Zero Intercept, Customer Weighting Factor, Rate Design
TXU Gas Distribution	9400	Depreciation, Net Salvage, Cash Working Capital, Affiliate Transactions, Software Amortization, Securitization, O&M Expenses, Safety Compliance
TXU Lone Star Pipeline	8976	Depreciation, Net Salvage, Cash Working Capital, ALG vs. ELG
Westar Transmissions Company	5787	Depreciation, Rate Base, Cost of Service, Rate Design, Contract Issues, Revenues, Losses, Income Taxes
TEXAS WATER COMMISSION		
JURISDICTION / COMPANY	DOCKET NO.	TESTIMONY TOPIC
City of Harlingen-Certificate for Convenience & Necessity	8480C/8485C/8512C	Rate Impact for CCN
City of Round Rock	8599/8600M	Rate Discrimination, Cost of Service
Devers Canal System	8388-M	Affiliate Transactions, O&M Expense, Return, Allocation, Acquisition Adjustment, Retroactive Ratemaking, Rate Case Expenses, Depreciation
Devers Canal System	30102-M	Cost of Service, Rate Base, Ratemaking Principles, Affiliate Transactions
Southern Utilities Company	7371-R	Affiliate Transactions, Cost of Service
Scenic Oaks Water Supply Corporation	8097-G	Affiliate Transactions, Cost of Service, Rate base, Cost of Capital, Rate Design, Depreciation
Sharyland Water Supply vs. United Irrigation District	8293-M	Rate Discrimination, Cost of Service, Rate Case Expenses
Southern Water Corporation	2008-1811-UCR	Cost of Service
Travis County Water Control & Improv. District No. 20		Cost of Service
EL PASO PUBLIC UTILITY REGULATION BOARD		
JURISDICTION / COMPANY	DOCKET NO.	TESTIMONY TOPIC
Southern Union Gas Company	1991	Depreciation, Calculation Procedure
Southern Union Gas Company	1997	Depreciation, Calculation Procedure

Southern Union Gas Company	GUD 8878 – 1998	Depreciation, Cash Working Capital, Rate Design, Rate Case Expenses
Texas Gas Services Company	2007	Revenue Requirements
Texas Gas Services Company	2011	Revenue Requirements
UTAH		
UTAH PUBLIC SERVICE COMMISSION		
JURISDICTION / COMPANY	DOCKET NO.	TESTIMONY TOPIC
PacifiCorp	98-2035-03	Production Plant Net Salvage, Production Life Span, Interim Additions, Mass Property, Depreciation
Questar	05-057-T01	Conservation Enabling Tariff Adjustment Option and Accounting Orders
Rocky Mountain Power	07-035-13	Depreciation
Rocky Mountain Power	13-035-02	Depreciation, Interim Additions, Production Plant Life Spans, Interim Retirements, Net Salvage, Mass Property Life
WYOMING		
WYOMING PUBLIC SERVICE COMMISSION		
JURISDICTION / COMPANY	DOCKET NO.	TESTIMONY TOPIC
PacifiCorp	20000-ER-00-162	Rate Parity

Exhibit JRW-1
Gulf Power Company
OPC's Recommended Cost of Capital

Weighted Average Cost of Capital - Regulatory Capital Structure

Capital	Capitalization Amounts	Capitalization Ratios	Cost Rate	Weighted Cost Rate
Short-Term Debt	$ 27,615	1.47%	0.82%	0.01%
Long-Term Debt	$ 685,025	36.36%	4.96%	1.80%
Preferred Stock	$ 79,085	4.20%	6.00%	0.25%
Common Equity	$ 715,221	37.96%	9.00%	3.42%
Customer Deposits	$ 20,943	1.11%	2.30%	0.03%
Deferred Taxes	$ 379,918	20.17%	0.00%	0.00%
FASB 109 Deferred Taxes	$ (25,718)	-1.37%	0.00%	0.00%
Investment Credit - Weighted Cost	$ 1,812	0.10%	6.86%	0.01%
Totals	$ 1,883,901	100.00%		5.52%

MFR D-1a

Panel B - OPC's Recommended Capitalization Ratios for Gulf Power - Investor-Provided Capital

Capital	Capitalization Amounts	Capitalization Ratios	Cost Rate	Weighted Cost Rate
Short-Term Debt	$ 27,615	1.83%	0.82%	0.02%
Long-Term Debt	$ 685,025	45.46%	4.96%	2.25%
Preferred Stock	$ 79,085	5.25%	6.00%	0.31%
Common Equity	$ 715,221	47.46%	9.00%	4.27%
	$ 1,506,946	100.00%		6.86%

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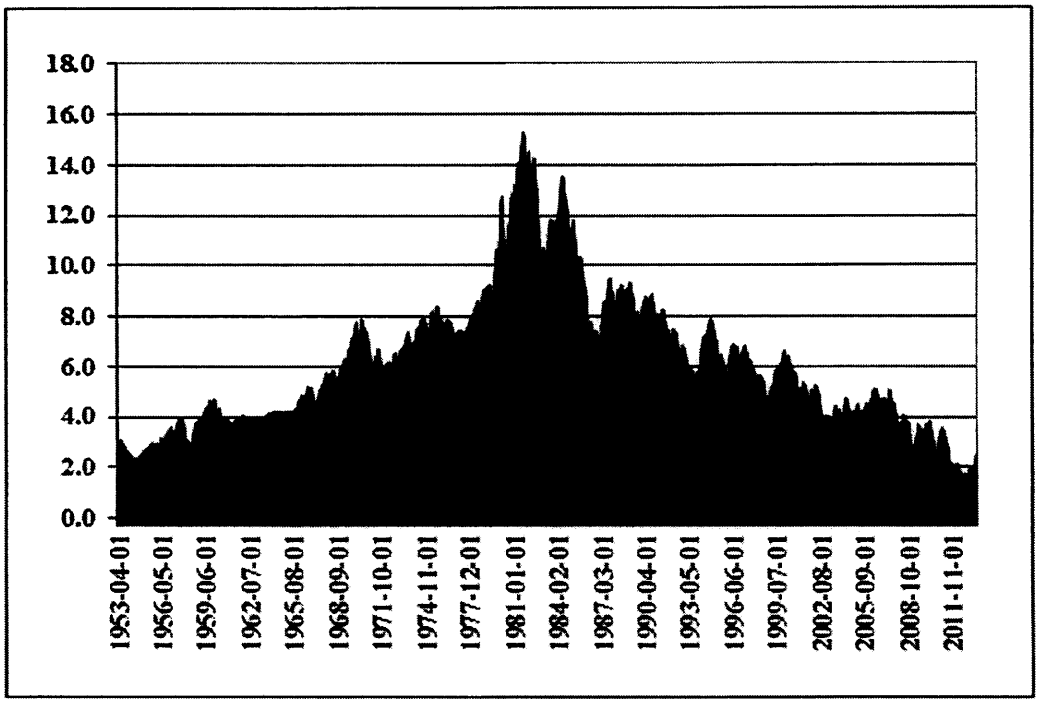
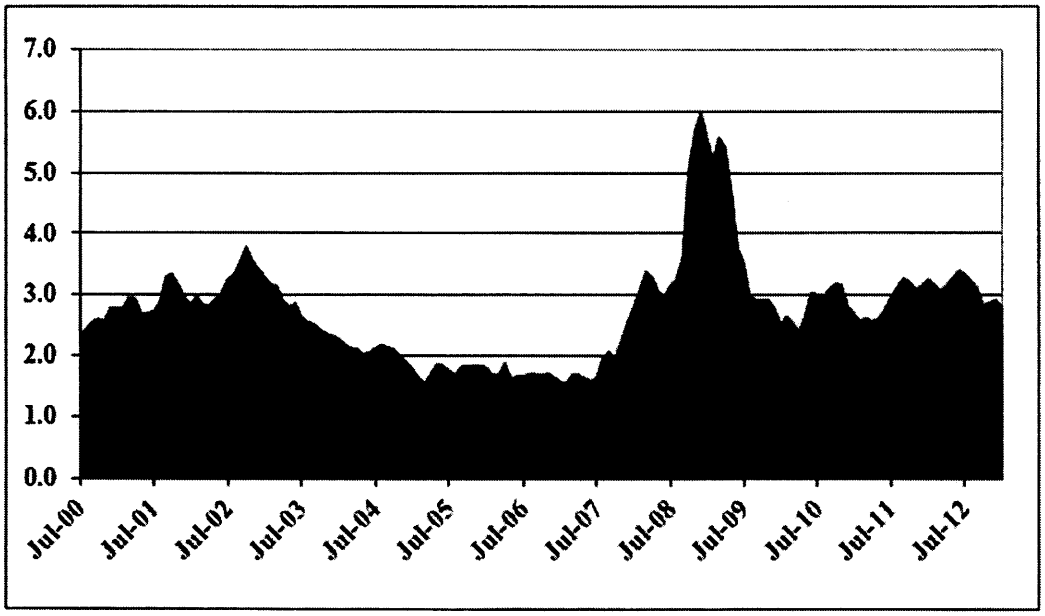
PARTY Office of Public Counsel (OPC) Direct
DESCRIPTION Randall Woodridge (JRW-1)
DATE

Exhibit JRW-2

Panel A
10-Year Treasury Yields
1953-Present



Panel B
Long-Term Moody's Baa Yields Minus 10-Year Treasury Yields
2000-Present



Source: Federal Reserve Bank of St. Louis, FRED Database.

FLORIDA PUBLIC SERVICE COMMISSION
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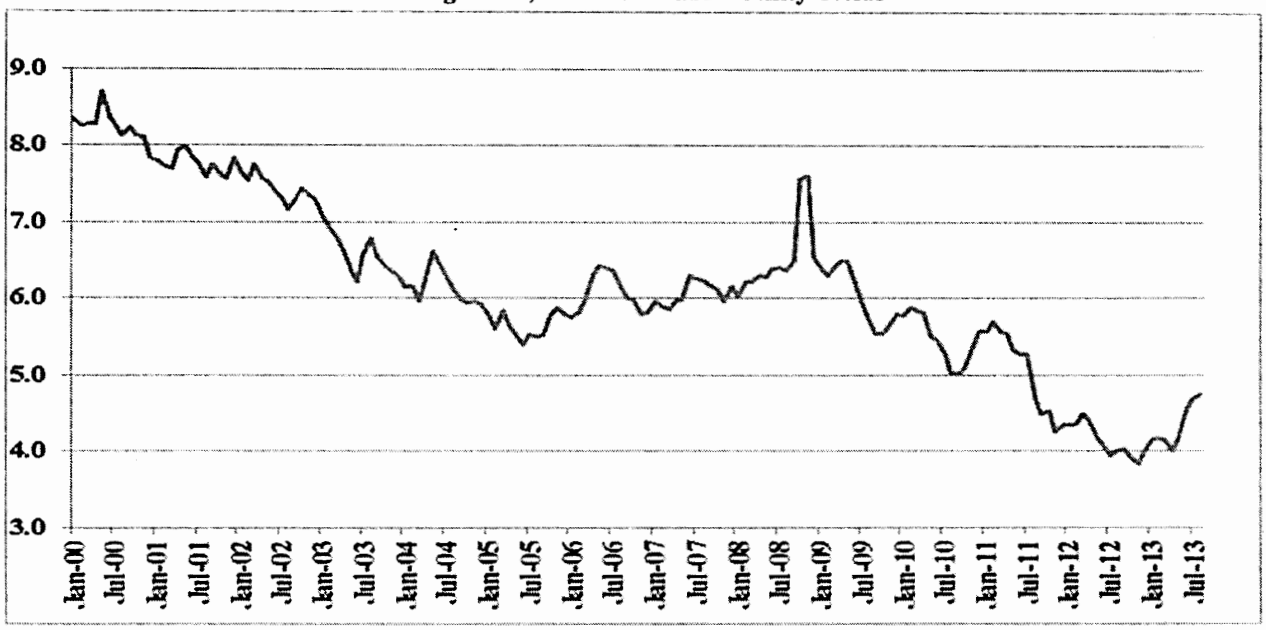
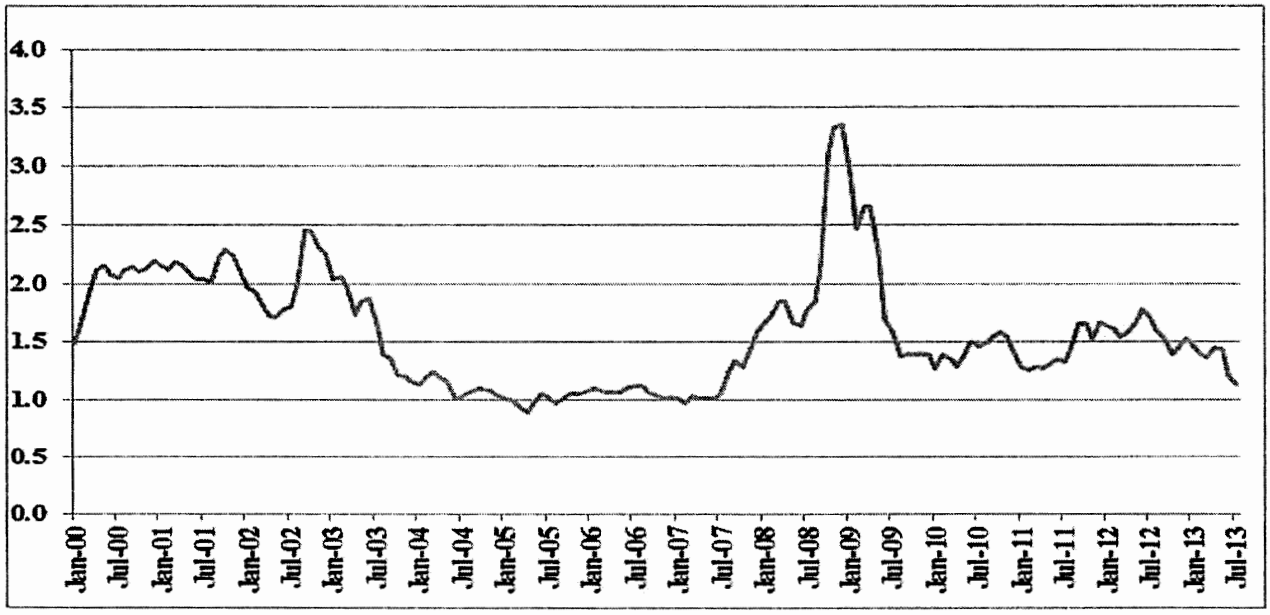
PARTY Office of Public Counsel (OPC) Direct
DESCRIPTION Randall Woodridge (JRW-2)
DATE

Exhibit JRW-3
Panel A
Long-Term, 'A' Rated Public Utility Yields



Panel B
Long-Term, 'A' Rated Public Utility Yields Minus 20-Year Treasury Yields



Source: Mergent Bond Record

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130140-EI EXHIBIT 47
PARTY Office of Public Counsel (OPC) Direct
DESCRIPTION Randall Woodridge (JRW-3)
DATE

Exhibit JRW-4
Gulf Power Company
Summary Financial Statistics

Electric Proxy Group

Company	Operating Revenue ($mil)	Percent Elec Revenue	Percent Gas Revenue	Net Plant ($mil)	Market Cap ($mil)	S&P Bond Rating	Moody's Bond Rating	Pre-Tax Interest Coverage	Primary Service Area	Common Equity Ratio	Return on Equity	Market to Book Ratio
ALLETE, Inc. (NYSE-ALE)	1,004.2	91		2,397.2	1.9	A-	A2	4.0	MN, WI	53.1	8.8	1.53
Alliant Energy Corporation (NYSE-LNT)	3,216.1	82	14	8,027.2	5.6	A-	A3	3.7	WS,IA	48.5	10.9	1.66
Ameren Corporation (NYSE-AEE)	6,388.0	84	16	15,601.0	8.1	BBB+/BBB	Baa1/Baa2	2.9	IL,MO	50.2	NM	1.27
American Electric Power Co. (NYSE-AEP)	15,177.0	90		39,425.0	20.8	BBB/BBB-	Baa2	3.2	10 States	44.8	7.9	1.34
Avista Corporation (NYSE-AVA)	1,586.1	63	30	3,104.2	1.6	A-	A3	2.9	WA,OR,ID	45.9	7.1	1.25
Black Hills Corporation (NYSE-BKH)	1,226.2	51	41	2,831.9	2.2	BBB	Baa1/Baa2	3.0	CO,SD,WY,MT	49.4	11.2	1.73
Cleco Corporation (NYSE-CNL)	1,035.6	95		3,042.2	2.7	BBB/BBB-	Baa2/Baa3	3.8	LA	53.3	10.4	1.80
CMS Energy Corporation (NYSE-CMS)	6,562.0	64	33	11,916.0	7.1	BBB+/BBB	Baa1	3.1	MI	30.3	13.6	2.14
Consolidated Edison, Inc. (NYSE-ED)	12,341.0	71	14	27,056.0	16.4	A-/BBB+	A3/Baa1	4.0	NY,PA	49.0	8.6	1.38
DTE Energy Company (NYSE-DTE)	9,258.0	57	16	15,190.0	11.8	A-/BBB+	A2/A3	3.3	MI	48.8	8.8	1.56
Duke Energy Corporation (NYSE-DUK)	24,194.0	84	2	68,877.0	46.8	BBB+	A3/Baa1	2.8	NC,SC,FL,OH,KY	49.2	6.4	1.17
Edison International (NYSE-EIX)	11,810.0	97		29,301.0	15.2	BBB+	A3	5.1	CA	43.3	NM	1.62
FirstEnergy Corporation (ASE-FE)	14,604.0	51		33,091.0	15.2	BBB	Baa2	2.2	OH,PA,NJ,WV,MD,NY	38.3	2.3	1.19
Great Plains Energy Incorporated (NYSE-GXP)	2,369.1	100		7,581.2	3.5	BBB	Baa2	2.9	MO,KS	45.6	7.2	1.02
Hawaiian Electric Industries, Inc. (NYSE-HE)	3,286.7	92		3,701.9	2.5	BBB-	Baa2	4.2	HI	47.8	8.5	1.55
IDACORP, Inc. (NYSE-IDA)	1,153.7	100		3,587.2	2.5	A-	A2	3.5	ID	50.7	10.7	1.37
MGE Energy, Inc. (NYSE-MGEE)	570.4	70	29	1,123.3	1.3	AA-	Aa2	7.0	WI	61.5	12.2	2.13
Nextera Energy (NYSE-NEE)	14,330.0	71		50,460.0	34.7	A-/BBB+	Aa3	3.3	FL	37.0	10.7	2.09
Northeast Utilities (NYSE-NU)	7,176.4	87	11	16,931.4	13.0	A-	Baa1	3.8	CT,NH,MA	50.2	8.5	1.38
NorthWestern Corporation (NYSE-NWE)	1,089.8	75	25	2,532.4	1.7	A-	A2	2.5	SD,MT,NE	46.5	11.3	1.69
Otter Tail Corporation (NDQ-OTTR)	728.3	86		1072.8	0.9	BBB-	Baa3	2.9	ND,SD,MN	54.5	5.1	1.67
Pepco Holdings, Inc. (NYSE-POM)	4,515.0	94	4	9,253.0	4.8	A-/BBB+	Baa1/Baa2	3.7	DC,MD,VA,NJ	44.6	NM	1.12
PG&E Corporation (NYSE-PCG)	15,254.0	80	15	39,067.0	18.9	BBB/BBB-	A3/Baa1	2.6	CA	49.0	6.9	1.36
Pinnacle West Capital Corp. (NYSE-PNW)	3,405.1	100		10,309.6	6.0	BBB	Baa1	4.4	AZ	52.9	10.8	1.49
PNM Resources, Inc. (NYSE-PNM)	1,378.4	100		3,807.4	1.8	BBB	Baa3	2.4	NM,TX	44.7	6.5	1.10
Portland General Electric Company (NYSE-POR)	1,789.0	100		4,532.0	2.2	A-	A2	2.8	OR	50.3	5.4	1.25
PPL Corporation (NYSE-PPL)	11,532.0	59		30,600.0	18.1	A-	A2	2.9	PA,KY	34.4	14	1.65
SCANA Corporation (NYSE-SCG)	4,487.0	56	18	11,348.0	6.8	BBB+	Baa1/Baa2	3.2	SC,NC,GA	43.9	10.9	1.50
Southern Company (NYSE-SO)	16,895.0	95		49,317.0	36.8	A	A3/Baa1	5.3	GA,AL,FL,MS	45.3	9.2	1.96
UNS Energy Corp. (NYSE-UNS)	1,473.1	91	9	3,367.4	1.9	BBB-	Baa2	3.0	AZ	36.9	9.8	1.78
Westar Energy, Inc. (NYSE-WR)	2,335.3	100		7,557.3	4.0	A-	A3	3.5	KS	44.9	10.6	1.36
Wisconsin Energy Corporation (NYSE-WEC)	4,398.0	74	24	10,704.5	9.3	A-/BBB+	A2/A3	4.0	WI	45.0	13.2	2.20
Xcel Energy Inc. (NYSE-XEL)	10,637.2	83	11	24,813.4	13.8	A-	A3	3.6	MN,WI,ND,SD,MI	44.8	10.9	1.48
Mean	6,582.0	82	18	16,712.9	10.3	A-/BBB+	A3	3.5		46.5	9.3	1.54
Median	4,398.0	84	16	10,309.6	6.0	A-/BBB+	A3	3.3		46.5	9.5	1.50
Southern Company (NYSE-SO)	16,895.0	95		49,317.0	36.8	A	A3/Baa1	4.8	GA,AL,FL,MS	45.3	9.2	1.96

Data Source: *AUS Utility Reports*, September, 2013; Pre-Tax Interest Coverage and Primary Service Territory are from *Value Line Investment Survey*, 2013.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130140-EI EXHIBIT 48
PARTY Office of Public Counsel (OPC) Direct
DESCRIPTION Randall Woodridge (JRW-4)
DATE

Exhibit JRW-4
Gulf Power Company
Summary Financial Statistics

Vander Weide Proxy Group

Company	Operating Revenue ($mil)	Percent Elec Revenue	Percent Gas Revenue	Net Plant ($mil)	Market Cap ($mil)	S&P Bond Rating	Moody's Bond Rating	Pre-Tax Interest Coverage	Primary Service Area	Common Equity Ratio	Return on Equity	Market to Book Ratio
ALLETE, Inc. (NYSE-ALE)	1,004.2	91		2,397.2	1.9	A-	A2	4.0	MN, WI	53.1	8.8	1.53
Alliant Energy Corporation (NYSE-LNT)	3,216.1	82	14	8,027.2	5.6	A-	A3	3.7	WS,IA	48.5	10.9	1.66
American Electric Power Co. (NYSE-AEP)	15,177.0	90		39,425.0	20.8	BBB/BBB-	Baa2	3.2	10 States	44.8	7.9	1.34
Black Hills Corporation (NYSE-BKH)	1,226.2	51	41	2,831.9	2.2	BBB	Baa1/Baa2	3.0	CO,SD,WY,MT	49.4	11.2	1.73
CenterPoint Energy (NYSE-CNP)	8,125.0	29	39	9,184.0	9.8	A-/BBB+	Baa1/Baa2	2.7	TX,LA,MS,AR,OK,MN	32.8	4.5	2.34
CMS Energy Corporation (NYSE-CMS)	6,562.0	64	33	11,916.0	7.1	BBB+/BBB	Baa1	3.1	MI	30.3	13.6	2.14
Dominion Resources, Inc. (NYSE-D)	13,081.0	43	2	31,554.0	33.2	A-	Baa1/Baa2	3.5	VA,NC,WV,OH	32.9	2.2	3.02
DTE Energy Company (NYSE-DTE)	9,258.0	57	16	15,190.0	11.8	A-/BBB+	A2/A3	3.3	MI	48.8	8.8	1.56
Duke Energy Corporation (NYSE-DUK)	24,194.0	84	2	68,877.0	46.8	BBB+	A3/Baa1	2.8	NC,SC,FL,OH,KY	49.2	6.4	1.17
Entergy Corporation (NYSE-ETR)	10,746.9	77	1	27,572.1	11.3	BBB+/BBB	Baa2	3.1	LA,MS,AR	40.0	10.4	1.21
Great Plains Energy Incorporated (NYSE-GXP)	2,369.1	100		7,581.2	3.5	BBB	Baa2	2.9	MO,KS	45.6	7.2	1.02
Hawaiian Electric Industries, Inc. (NYSE-HE)	3,286.7	92		3,701.9	2.5	BBB-	Baa2	4.2	HI	47.8	8.5	1.55
Integrys Energy Group (NYSE-TEG)	4,918.7	26	39	6,062.6	4.6	A-	A2/A3	5.8	WI,IL,MN,MI	51.3	10.1	1.43
Nextera Energy (NYSE-NEE)	14,330.0	71		50,460.0	34.7	A-/BBB+	Aa3	3.3	FL	37.0	10.7	2.09
Northeast Utilities (NYSE-NU)	7,176.4	87	11	16,931.4	13.0	A-	Baa1	3.8	CT,NH,MA	50.2	8.5	1.38
NorthWestern Corporation (NYSE-NWE)	1,089.8	75	25	2,532.4	1.7	A-	A2	2.5	SD,MT,NE	46.5	11.3	1.69
OGE Energy Corp. (NYSE-OGE)	3,611.1	61		6,382.9	14.1	BBB+	Baa1	4.1	OK,AR	49.4	12.5	2.39
Otter Tail Corporation (NDQ-OTTR)	728.3	86		1072.8	0.9	BBB-	Baa3	2.9	ND,SD,MN	54.5	5.1	1.67
Pepco Holdings, Inc. (NYSE-POM)	4,515.0	94	4	9,253.0	4.8	A-/BBB+	Baa1/Baa2	3.7	DC,MD,VA,NJ	44.6	NM	1.12
Pinnacle West Capital Corp. (NYSE-PNW)	3,405.1	100		10,309.6	6.0	BBB	Baa1	4.4	AZ	52.9	10.8	1.49
PNM Resources, Inc. (NYSE-PNM)	1,378.4	100		3,807.4	1.8	BBB	Baa3	2.4	NM,TX	44.7	6.5	1.10
Portland General Electric Company (NYSE-POR)	1,789.0	100		4,532.0	2.2	A-	A2	2.8	OR	50.3	5.4	1.25
SCANA Corporation (NYSE-SCG)	4,487.0	56	18	11,348.0	6.8	BBB+	Baa1/Baa2	3.2	SC,NC,GA	43.9	10.9	1.50
SEMPRA Energy (NYSE-SRE)	10,479.0	34	39	25,171.0	20.0	A/A-	A2	2.8	CA	44.0	9.7	1.89
Southern Company (NYSE-SO)	16,895.0	95		49,317.0	36.8	A	A3/Baa1	5.3	GA,AL,FL,MS	45.3	9.2	1.96
TECO Energy, Inc. (NYSE-TE)	2,944.0	66	14	6,040.5	3.6	BBB+/BBB	A3	3.4	FL	43.6	7.9	1.56
Vectren Corporation (NYSE-VVC)	2,389.2	26	33	3,160.6	2.8	A/A-	A2	3.6	IN,OH	44.3	8.4	1.82
Westar Energy, Inc. (NYSE-WR)	2,335.3	100		7,557.3	4.0	A-	A3	3.5	KS	44.9	10.6	1.36
Wisconsin Energy Corporation (NYSE-WEC)	4,398.0	74	24	10,704.5	9.3	A-/BBB+	A2/A3	4.0	WI	45.0	13.2	2.20
Xcel Energy Inc. (NYSE-XEL)	10,637.2	83	11	24,813.4	13.8	A-	A3	3.6	MN,WI,ND,SD,MI	44.8	10.9	1.48
Mean	6,525.1	73	20	15,923.8	11.2	A-/BBB+	A3/Baa1	3.5		45.3	9.0	1.65
Median	4,442.5	80	17	9,218.5	6.4	A-/BBB+	A3/Baa1	3.4		45.2	9.2	1.55

Southern Company (NYSE-SO)	16,895.0	95		49,317.0	36.8	A	A3/Baa1	4.8	GA,AL,FL,MS	45.3	9.2	1.96

Data Source: *AUS Utility Reports*, September, 2013; Pre-Tax Interest Coverage and Primary Service Territory are from *Value Line Investment Survey*, 2013.

Exhibit JRW-4
Gulf Power Company
Value Line Risk Metrics

Electric Proxy Group

Company	Beta	Financial Strength	Safety	Stock Price Stability
ALLETE, Inc. (NYSE-ALE)	0.70	2	A	100
Alliant Energy Corporation (NYSE-LNT)	0.75	2	A	95
Ameren Corporation (NYSE-AEE)	0.80	3	B++	95
American Electric Power Co. (NYSE-AEP)	0.70	3	B++	100
Avista Corporation (NYSE-AVA)	0.70	2	A	95
Black Hills Corporation (NYSE-BKH)	0.85	3	B+	90
Cleco Corporation (NYSE-CNL)	0.65	1	A	100
CMS Energy Corporation (NYSE-CMS)	0.75	3	B+	95
Consolidated Edison, Inc. (NYSE-ED)	0.60	1	A+	100
DTE Energy Company (NYSE-DTE)	0.75	2	B++	100
Duke Energy Corporation (NYSE-DUK)	0.60	2	A	100
Edison International (NYSE-EIX)	0.75	2	B++	95
FirstEnergy Corporation (ASE-FE)	0.80	3	B+	90
Great Plains Energy Incorporated (NYSE-GXP)	0.80	3	B+	90
Hawaiian Electric Industries, Inc. (NYSE-HE)	0.70	2	B++	90
IDACORP, Inc. (NYSE-IDA)	0.70	2	B++	100
MGE Energy, Inc. (NYSE-MGEE)	0.60	1	A	100
Nextera Energy (NYSE-NEE)	0.70	2	A	100
Northeast Utilities (NYSE-NU)	0.75	2	B++	100
NorthWestern Corporation (NYSE-NWE)	0.70	3	B+	100
Otter Tail Corporation (NDQ-OTTR)	0.90	3	B+	80
Pepco Holdings, Inc. (NYSE-POM)	0.75	3	B	95
PG&E Corporation (NYSE-PCG)	0.55	3	B+	100
Pinnacle West Capital Corp. (NYSE-PNW)	0.70	1	A	100
PNM Resources, Inc. (NYSE-PNM)	0.90	3	B	80
Portland General Electric Company (NYSE-POR)	0.75	2	B++	100
PPL Corporation (NYSE-PPL)	0.65	3	B++	95
SCANA Corporation (NYSE-SCG)	0.65	2	B++	100
Southern Company (NYSE-SO)	0.55	1	A	100
UNS Energy Corp. (NYSE-UNS)	0.70	3	B+	100
Westar Energy, Inc. (NYSE-WR)	0.75	2	B++	100
Wisconsin Energy Corporation (NYSE-WEC)	0.65	1	A	100
Xcel Energy Inc. (NYSE-XEL)	0.65	2	B++	100
Mean	0.71	2.21	B++	97
Median	0.70	2.00	B++	100

Data Source: *Value Line Investment Survey*, 2013.

Exhibit JRW-4
Gulf Power Company
Value Line Risk Metrics

Vander Weide Proxy Group

Company	Beta	Financial Strength	Safety	Stock Price Stability
ALLETE, Inc. (NYSE-ALE)	0.70	2	A	100
Alliant Energy Corporation (NYSE-LNT)	0.75	2	A	95
American Electric Power Co. (NYSE-AEP)	0.70	3	B++	100
Black Hills Corporation (NYSE-BKH)	0.85	3	B+	90
CenterPoint Energy (NYSE-CNP)	0.80	2	B++	90
CMS Energy Corporation (NYSE-CMS)	0.75	3	B+	95
Dominion Resources, Inc. (NYSE-D)	0.70	2	B++	100
DTE Energy Company (NYSE-DTE)	0.75	2	B++	100
Duke Energy Corporation (NYSE-DUK)	0.60	2	A	100
Entergy Corporation (NYSE-ETR)	0.70	3	B++	100
Great Plains Energy Incorporated (NYSE-GXP)	0.80	3	B+	90
Hawaiian Electric Industries, Inc. (NYSE-HE)	0.70	2	B++	90
Integrys Energy Group (NYSE-TEG)	0.90	2	A	75
Nextera Energy (NYSE-NEE)	0.70	2	A	100
Northeast Utilities (NYSE-NU)	0.75	2	B++	100
NorthWestern Corporation (NYSE-NWE)	0.70	3	B+	100
OGE Energy Corp. (NYSE-OGE)	0.75	2	A	95
Otter Tail Corporation (NDQ-OTTR)	0.90	3	B+	80
Pepco Holdings, Inc. (NYSE-POM)	0.75	3	B	95
Pinnacle West Capital Corp. (NYSE-PNW)	0.70	1	A	100
PNM Resources, Inc. (NYSE-PNM)	0.90	3	B	80
Portland General Electric Company (NYSE-POR)	0.75	2	B++	100
SCANA Corporation (NYSE-SCG)	0.65	2	B++	100
SEMPRA Energy (NYSE-SRE)	0.80	2	A	95
Southern Company (NYSE-SO)	0.55	1	A	100
TECO Energy, Inc. (NYSE-TE)	0.85	2	B++	90
Vectren Corporation (NYSE-VVC)	0.75	2	A	95
Westar Energy, Inc. (NYSE-WR)	0.75	2	B++	100
Wisconsin Energy Corporation (NYSE-WEC)	0.65	1	A	100
Xcel Energy Inc. (NYSE-XEL)	0.65	2	B++	100
Mean	0.74	2.20	B++	95
Median	0.75	2.00	B++	100

Data Source: *Value Line Investment Survey*, 2013.

Exhibit JRW-5
Gulf Power Company
Capital Structure Ratios

Panel A - Gulf's Recommended Capitalization Ratios - Investor-Provided Capital

Capital	Capitalization Amounts	Capitalization Ratios
Short-Term Debt	$ 27,615	1.83%
Long-Term Debt	$ 685,025	45.46%
Preferred Stock	$ 79,085	5.25%
Common Equity	$ 715,221	47.46%
	$ 1,506,946	100.00%

Panel B - OPC's Recommended Capitalization Ratios - Investor-Provided Capital

Capital	Capitalization Amounts	Capitalization Ratios
Short-Term Debt	$ 27,615	1.83%
Long-Term Debt	$ 685,025	45.46%
Preferred Stock	$ 79,085	5.25%
Common Equity	$ 715,221	47.46%
	$ 1,506,946	100.00%

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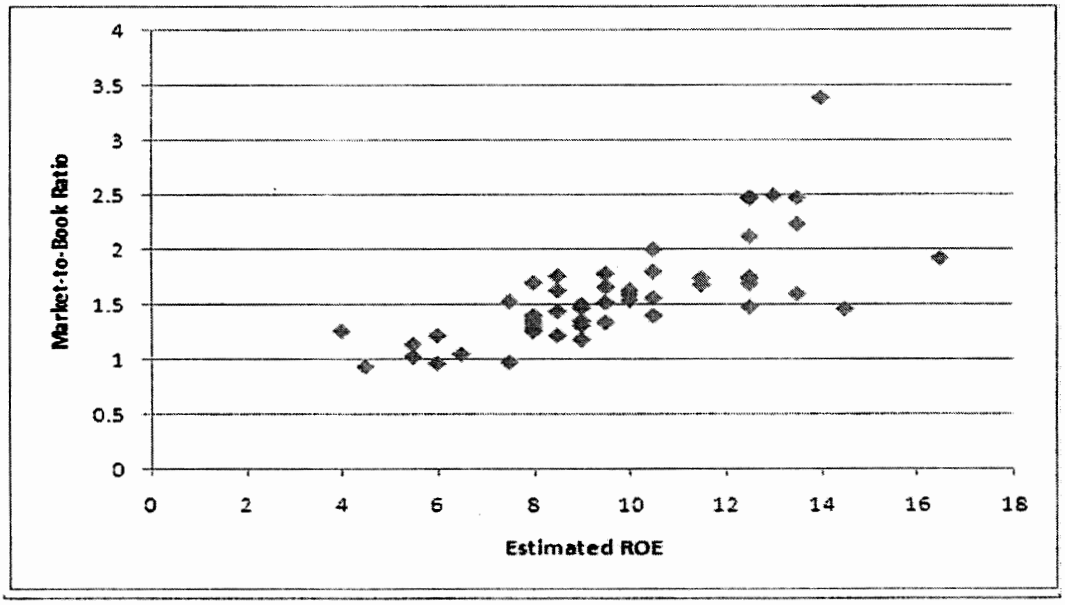
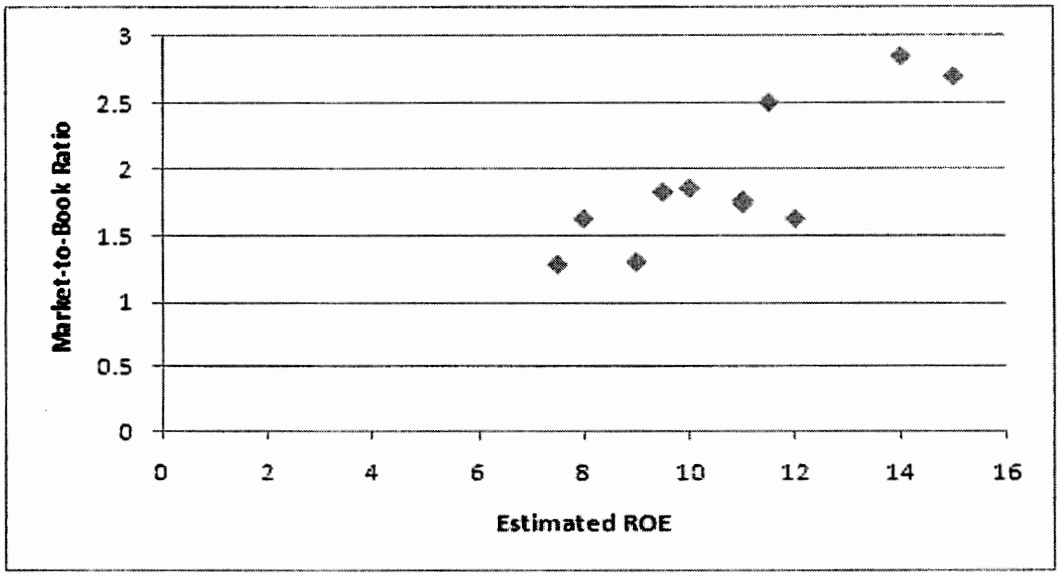
Exhibit JRW-6
Electric Utilities
Panel A



R-Square = .52, N=51.

Gas Companies
Panel B



R-Square = .71, N=11.

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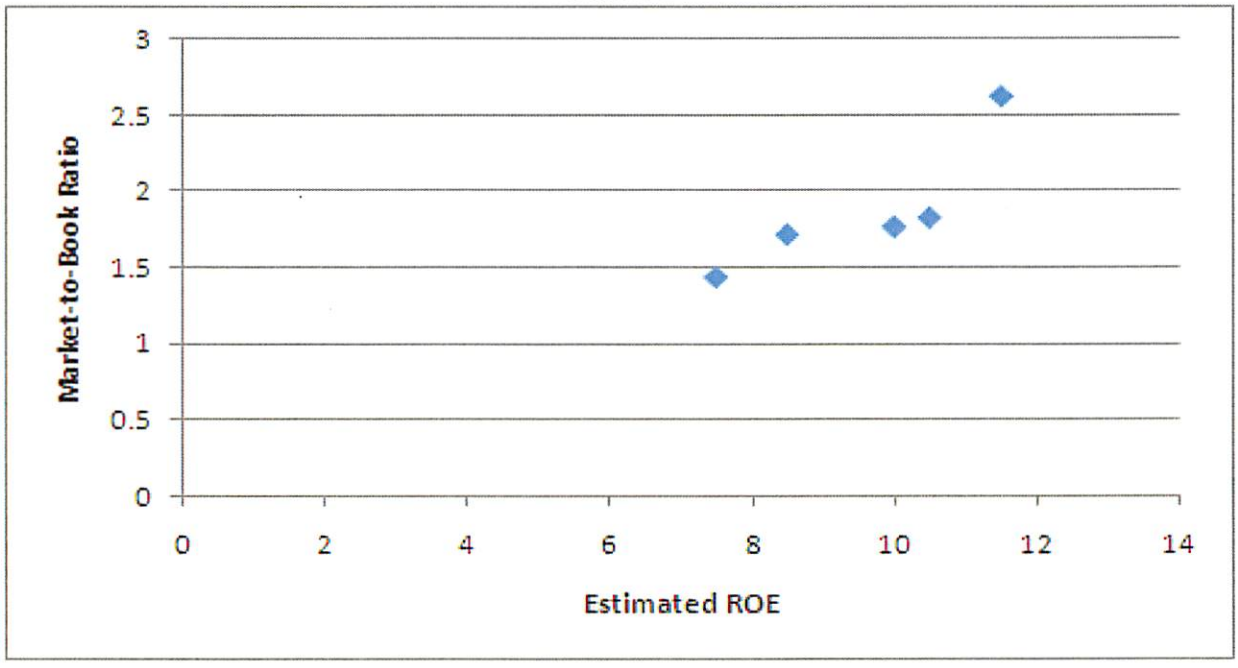
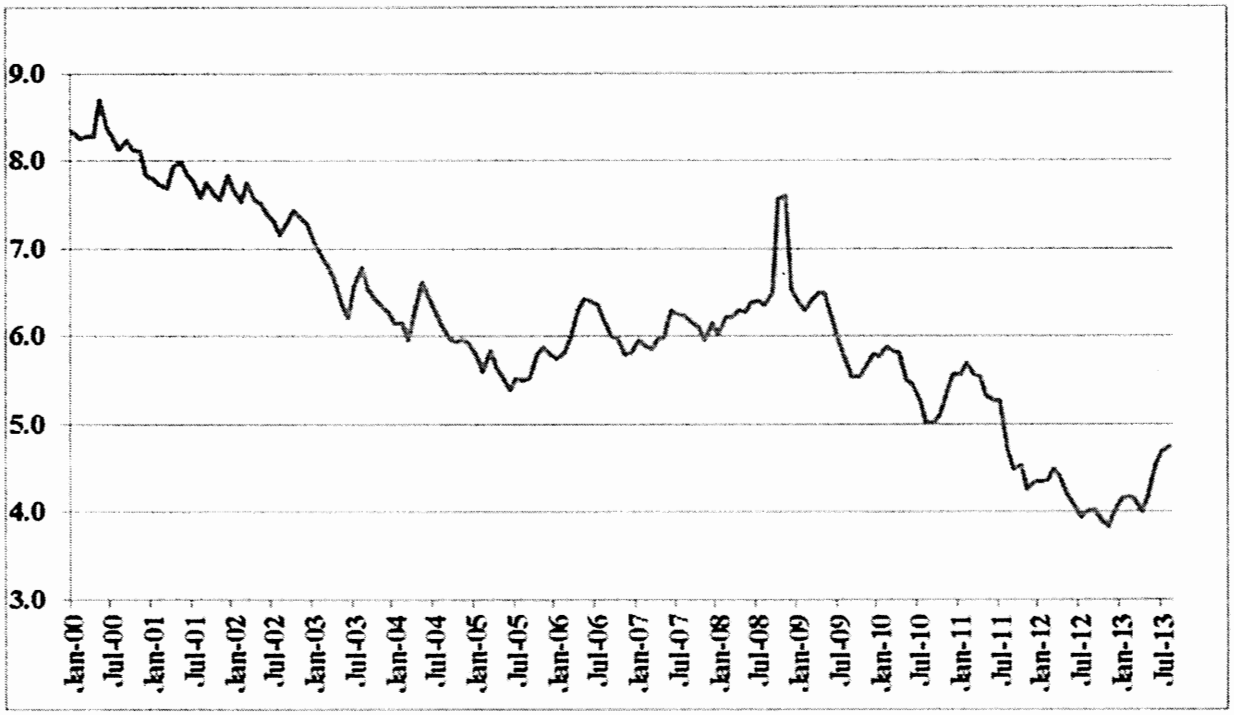
Exhibit JRW-6
Water Companies
Panel C



R-Square = .77, N=5.

Exhibit JRW-7
Long-Term 'A' Rated Public Utility Bonds



Data Source: Mergent Bond Record

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DESCRIPTION Randall Woodridge (JRW-7)
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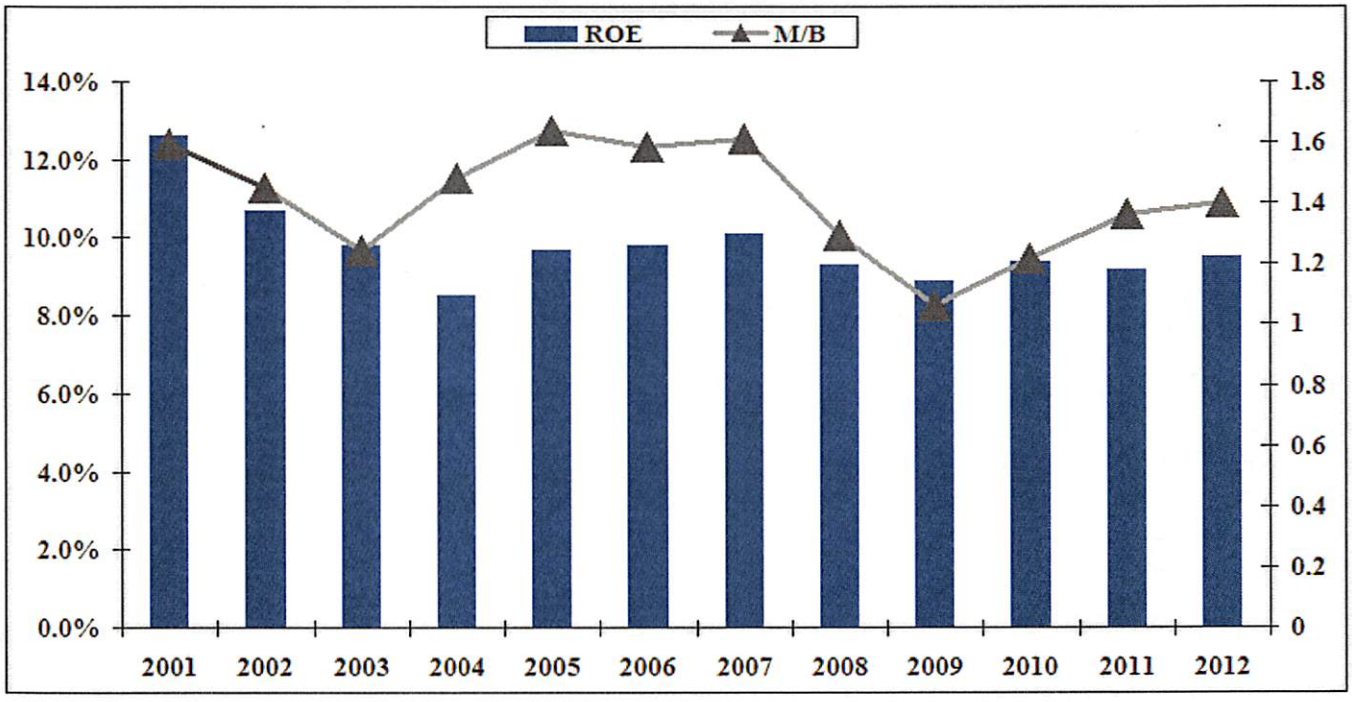
Exhibit JRW-7

Electric Proxy Group Average Dividend Yield

Data Source: *Value Line Investment Survey.*

Exhibit JRW-7

Electric Proxy Group Average Return on Equity and Market-to-Book Ratios



Data Source: *Value Line Investment Survey.*

Exhibit JRW-8

Industry Average Betas

Industry Name	No.	Beta	Industry Name	No.	Beta	Industry Name	No.	Beta
Public/Private Equity	11	2.18	Natural Gas (Div.)	29	1.33	IT Services	60	1.06
Advertising	31	2.02	Financial Svcs. (Div.)	225	1.31	Retail Building Supply	8	1.04
Furn/Home Furnishings	35	1.81	Toiletries/Cosmetics	15	1.30	Computer Software	184	1.04
Heavy Truck & Equip	21	1.80	Apparel	57	1.30	Med Supp Non-Invasiv	146	1.03
Semiconductor Equip	12	1.79	Computers/Peripherals	87	1.30	Biotechnology	158	1.03
Retail (Hardlines)	75	1.77	Retail Store	37	1.29	E-Commerce	57	1.03
Newspaper	13	1.76	Chemical (Specialty)	70	1.28	Telecom. Equipment	99	1.02
Hotel/Gaming	51	1.74	Precision Instrument	77	1.28	Pipeline MLPs	27	0.98
Auto Parts	51	1.70	Wireless Networking	57	1.27	Telecom. Services	74	0.98
Steel	32	1.68	Restaurant	63	1.27	Oil/Gas Distribution	13	0.96
Entertainment	77	1.63	Shoe	19	1.25	Utility (Foreign)	4	0.96
Metal Fabricating	24	1.59	Publishing	24	1.25	Industrial Services	137	0.93
Automotive	12	1.59	Trucking	36	1.24	Bank (Midwest)	45	0.93
Insurance (Life)	30	1.58	Human Resources	23	1.24	Reinsurance	13	0.93
Oilfield Svcs/Equip.	93	1.55	Entertainment Tech	40	1.23	Food Processing	112	0.91
Coal	20	1.53	Engineering & Const	25	1.22	Medical Services	122	0.91
Chemical (Diversified)	31	1.51	Air Transport	36	1.21	Insurance (Prop/Cas.)	49	0.91
Building Materials	45	1.50	Machinery	100	1.20	Beverage	34	0.88
Semiconductor	141	1.50	Securities Brokerage	28	1.20	Telecom. Utility	25	0.88
R.E.I.T.	5	1.47	Petroleum (Integrated)	20	1.18	Tobacco	11	0.85
Homebuilding	23	1.45	Healthcare Information	25	1.17	Med Supp Invasive	83	0.85
Recreation	56	1.45	Packaging & Container	26	1.16	Educational Services	34	0.83
Railroad	12	1.44	Precious Metals	84	1.15	Environmental	82	0.81
Retail (Softlines)	47	1.44	Diversified Co.	107	1.14	Bank	426	0.77
Maritime	52	1.40	Funeral Services	6	1.14	Electric Util. (Central)	21	0.75
Office Equip/Supplies	24	1.38	Property Management	31	1.13	Electric Utility (West)	14	0.75
Cable TV	21	1.37	Pharmacy Services	19	1.12	Retail/Wholesale Food	30	0.75
Retail Automotive	20	1.37	Drug	279	1.12	Thrift	148	0.71
Chemical (Basic)	16	1.36	Aerospace/Defense	64	1.10	Electric Utility (East)	21	0.70
Paper/Forest Products	32	1.36	Foreign Electronics	9	1.09	Natural Gas Utility	22	0.66
Power	93	1.35	Internet	186	1.09	Water Utility	11	0.66
Petroleum (Producing)	176	1.34	Information Services	27	1.07	Total Market	5891	1.15
Electrical Equipment	68	1.33	Household Products	26	1.07			
Metals & Mining (Div.)	73	1.33	Electronics	139	1.07			

Source: Damodaran Online 2012 - http://pages.stern.nyu.edu/~adamodar/

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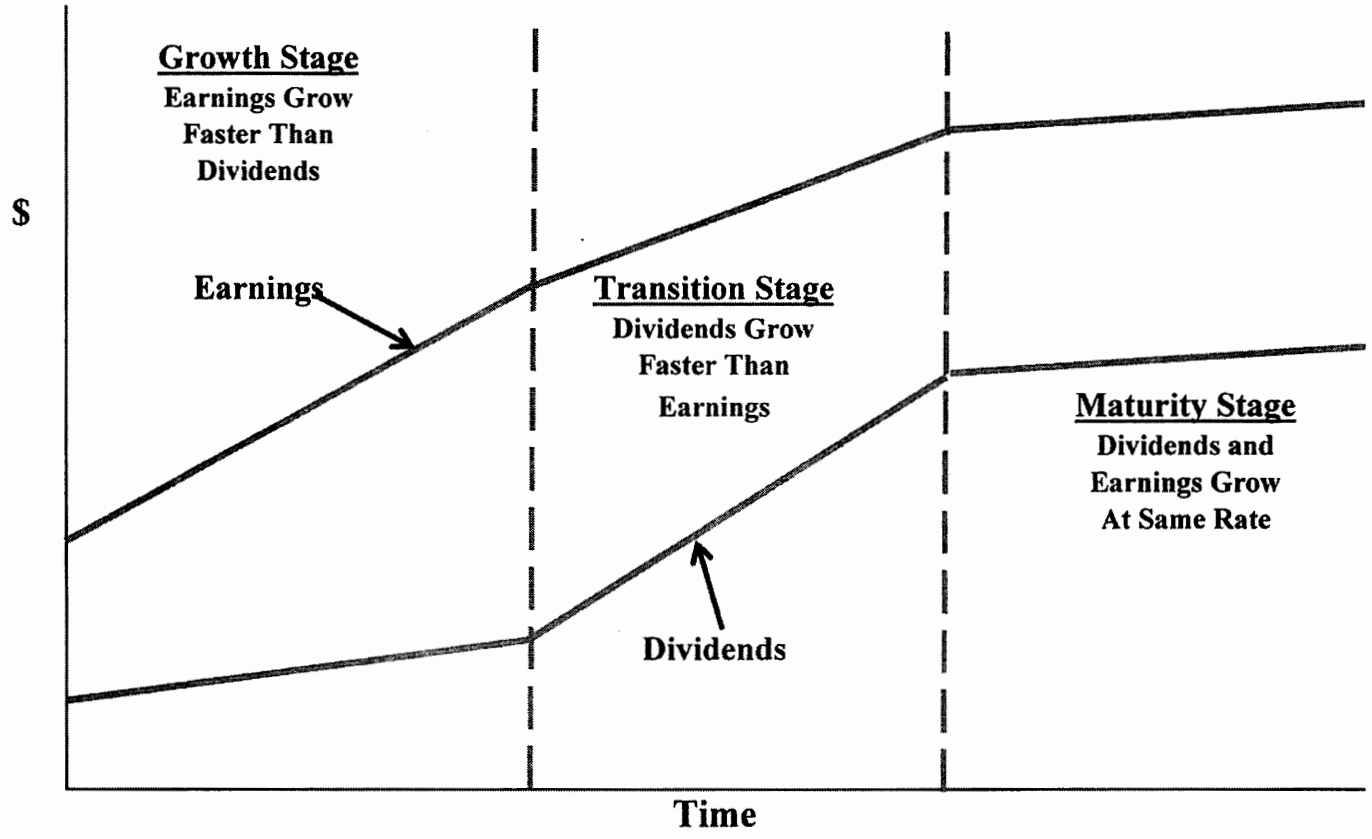
Exhibit JRW-9
DCF Model



Source: William F. Sharpe, Gordon J. Alexander, and Jeffrey V. Bailey, Investments (Prentice-Hall, 1995), pp. 590-91.

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Exhibit JRW-9
DCF Model
Consensus Earnings Estimates
Alliant Energy Corp ("LNT")

www.reuters.com

8/30/2013

	# of Estimates	Mean	High	Low
Earnings (per share)				
Quarter Ending Dec-13	4	0.52	0.58	0.44
Quarter Ending Mar-14	1	0.66	0.66	0.66
Year Ending Dec-13	10	3.13	3.20	3.08
Year Ending Dec-14	10	3.31	3.35	3.25
LT Growth Rate (%)	2	5.40	6.00	4.80

Data Source: www.reuters.com

Exhibit JRW-10

Gulf Power Company
Discounted Cash Flow Analysis

Panel A
Electric Proxy Group

Dividend Yield*	4.10%
Adjustment Factor	1.023
Adjusted Dividend Yield	4.2%
Growth Rate**	4.60%
Equity Cost Rate	8.8%

* Page 2 of Exhibit JRW-10
** Based on data provided on pages 4, 6, 8, and 10 of Exhibit JRW-10

Panel B
Vander Weide Proxy Group

Dividend Yield*	4.10%
Adjustment Factor	1.024
Adjusted Dividend Yield	4.2%
Growth Rate**	4.80%
Equity Cost Rate	9.0%

* Page 3 of Exhibit JRW-10
** Based on data provided on pages 5, 7, 9, and 10 of Exhibit JRW-10

FLORIDA PUBLIC SERVICE COMMISSION
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PARTY Office of Public Counsel (OPC) Direct
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Exhibit JRW-10

Gulf Power Company
Dividend Yields
Electric Proxy Group

Company	Apr	May	Jun	Jul	Aug	Sept	Mean
ALLETE, Inc. (NYSE-ALE)	3.8%	3.6%	4.0%	3.5%	4.0%	4.0%	3.8%
Alliant Energy Corporation (NYSE-LNT)	3.6%	3.9%	4.0%	3.5%	3.7%	3.8%	3.8%
Ameren Corporation (NYSE-AEE)	4.7%	4.4%	4.9%	4.4%	4.8%	4.6%	4.6%
American Electric Power Co. (NYSE-AEP)	3.7%	4.0%	4.5%	4.2%	4.6%	4.4%	4.2%
Avista Corporation (NYSE-AVA)	4.5%	4.2%	4.7%	4.2%	4.5%	4.6%	4.5%
Black Hills Corporation (NYSE-BKH)	3.3%	3.0%	3.3%	2.9%	3.0%	3.1%	3.1%
Cleco Corporation (NYSE-CNL)	2.9%	3.0%	3.3%	3.0%	3.2%	3.3%	3.1%
CMS Energy Corporation (NYSE-CMS)	3.5%	3.5%	3.9%	3.6%	3.8%	3.8%	3.7%
Consolidated Edison, Inc. (NYSE-ED)	3.9%	4.0%	4.4%	4.1%	4.4%	4.3%	4.2%
DTE Energy Company (NYSE-DTE)	3.4%	3.5%	4.1%	3.7%	3.9%	3.9%	3.8%
Duke Energy Corporation (NYSE-DUK)	4.1%	4.3%	4.7%	4.3%	4.7%	4.6%	4.5%
Edison International (NYSE-EIX)	2.6%	2.8%	3.0%	2.7%	2.9%	3.2%	2.9%
FirstEnergy Corporation (ASE-FE)	4.8%	5.1%	6.1%	5.7%	6.0%	5.8%	5.6%
Great Plains Energy Incorporated (NYSE-GXP)	3.7%	3.6%	4.0%	3.5%	3.9%	3.9%	3.8%
Hawaiian Electric Industries, Inc. (NYSE-HE)	4.6%	4.5%	5.2%	4.6%	4.9%	4.9%	4.8%
IDACORP, Inc. (NYSE-IDA)	3.2%	3.1%	3.3%	3.2%	3.1%	3.2%	3.2%
MGE Energy (NDQ-MGEE)	2.9%	2.8%	3.0%	2.6%	2.9%	3.0%	2.9%
Nextera Energy (NYSE-NEE)	3.3%	3.5%	3.4%	3.1%	3.2%	3.2%	3.3%
Northeast Utilities (NYSE-NU)	3.3%	3.3%	3.7%	3.3%	3.6%	3.5%	3.5%
NorthWestern Corporation (NYSE-NWE)	3.7%	3.6%	4.0%	3.5%	3.8%	3.5%	3.7%
Otter Tail Corporation (NDQ-OTTR)	3.9%	4.0%	4.4%	3.7%	4.4%	4.2%	4.1%
Pepco Holdings, Inc. (NYSE-POM)	5.0%	4.9%	5.6%	5.3%	5.7%	5.8%	5.4%
PG&E Corporation (NYSE-PCG)	3.8%	3.9%	4.2%	4.0%	4.3%	4.3%	4.1%
Pinnacle West Capital Corp. (NYSE-PNW)	3.6%	3.6%	4.2%	3.6%	4.0%	3.9%	3.8%
PNM Resources, Inc. (NYSE-PNM)	2.8%	2.9%	3.1%	2.8%	2.9%	2.9%	2.9%
Portland General Electric (NYSE-POR)	3.5%	3.3%	3.7%	3.4%	3.9%	3.8%	3.6%
PPL Corporation (NYSE-PPL)	4.5%	4.6%	5.1%	4.7%	4.8%	4.8%	4.8%
SCANA Corporation (NYSE-SCG)	3.9%	3.8%	4.3%	3.9%	4.2%	4.3%	4.1%
Southern Company (NYSE-SO)	4.0%	4.4%	4.8%	4.5%	4.8%	4.8%	4.6%
UNS Energy Corp. (NYSE-UNS)	3.5%	3.5%	4.0%	3.4%	3.8%	3.7%	3.7%
Westar Energy, Inc. (NYSE-WR)	4.0%	4.0%	4.5%	4.0%	4.3%	4.5%	4.2%
Wisconsin Energy Corporation (NYSE-WEC)	3.1%	3.1%	3.5%	3.1%	3.7%	3.7%	3.4%
Xcel Energy Inc. (NYSE-XEL)	3.5%	3.6%	4.0%	3.7%	4.0%	4.0%	3.8%
Mean	3.7%	3.7%	4.1%	3.7%	4.1%	4.0%	3.9%
Median	3.7%	3.6%	4.0%	3.6%	4.0%	3.9%	3.8%

Data Source: AUS Utilities Report, Monthly issues

Annual Dividend	Dividend Yield 30 Day	Dividend Yield 60 Day	Dividend Yield 90 Day
1.90	4.00%	3.85%	3.87%
1.88	3.80%	3.69%	3.73%
1.60	4.72%	4.65%	4.69%
1.96	4.54%	4.44%	4.42%
1.22	4.64%	4.49%	4.52%
1.52	3.12%	3.02%	3.06%
1.45	3.23%	3.13%	3.15%
1.02	3.88%	3.77%	3.79%
2.46	4.42%	4.30%	4.31%
2.62	3.96%	3.88%	3.91%
3.12	4.70%	4.60%	4.63%
1.35	2.96%	2.88%	2.89%
2.20	5.91%	5.86%	5.89%
0.87	3.95%	3.81%	3.83%
1.24	4.97%	4.85%	4.90%
1.52	3.18%	3.06%	3.10%
1.63	3.06%	2.92%	2.94%
2.64	3.29%	3.21%	3.26%
1.47	3.60%	3.50%	3.52%
1.52	3.59%	3.62%	3.68%
1.19	4.36%	4.18%	4.20%
1.08	5.86%	5.65%	5.59%
1.82	4.45%	4.28%	4.22%
2.18	4.02%	3.90%	3.91%
0.66	2.99%	2.90%	2.93%
1.30	4.61%	4.43%	4.39%
1.47	4.85%	4.80%	4.88%
2.03	4.36%	4.18%	4.18%
2.03	4.91%	4.76%	4.73%
1.74	3.79%	3.66%	3.71%
1.36	4.46%	4.30%	4.32%
1.53	3.78%	3.69%	3.72%
1.12	4.07%	3.96%	3.96%
Mean	4.1%	4.0%	4.0%
Median	4.0%	3.9%	3.9%

Data Source: AUS Utilities Report, www.yahoo.com

Summary Dividend Yields

	Dividend Yield 6 Month	Dividend Yield 30 Day	Dividend Yield 60 Day	Dividend Yield 90 Day
Mean	3.9%	4.1%	4.0%	4.0%
Median	3.8%	4.0%	3.9%	3.9%

Exhibit JRW-10

Gulf Power Company
Dividend Yields
Vander Weide Proxy Group

Company	Apr	May	Jun	Jul	Aug	Sept	Mean
ALLETE, Inc. (NYSE-ALE)	3.8%	3.6%	4.0%	3.5%	4.0%	4.0%	3.8%
Alliant Energy Corporation (NYSE-LNT)	3.6%	3.9%	4.0%	3.5%	3.7%	3.8%	3.8%
American Electric Power Co. (NYSE-AEP)	3.7%	4.0%	4.5%	4.2%	4.6%	4.4%	4.2%
Black Hills Corporation (NYSE-BKH)	3.3%	3.0%	3.3%	2.9%	3.0%	3.1%	3.1%
CenterPoint Energy (NYSE-CNP)	3.4%	3.4%	3.7%	3.4%	3.6%	3.4%	3.5%
CMS Energy Corporation (NYSE-CMS)	3.5%	3.5%	3.9%	3.6%	3.8%	3.8%	3.7%
Dominion Resources, Inc. (NYSE-D)	3.7%	3.7%	4.2%	3.8%	3.9%	3.6%	3.8%
DTE Energy Company (NYSE-DTE)	3.4%	3.5%	4.1%	3.7%	3.9%	3.9%	3.8%
Duke Energy Corporation (NYSE-DUK)	4.1%	4.3%	4.7%	4.3%	4.7%	4.6%	4.5%
Entergy Corporation (NYSE-ETR)	4.8%	4.7%	5.0%	4.6%	5.2%	5.1%	4.9%
Great Plains Energy Incorporated (NYSE-GXP)	3.7%	3.6%	4.0%	3.5%	3.9%	3.9%	3.8%
Hawaiian Electric Industries, Inc. (NYSE-HE)	4.6%	4.5%	5.2%	4.6%	4.9%	4.9%	4.8%
Integrys Energy Group (NYSE-TEG)	4.5%	4.4%	4.9%	4.4%	4.7%	4.8%	4.6%
Nextera Energy (NYSE-NEE)	3.3%	3.5%	3.4%	3.1%	3.2%	3.2%	3.3%
Northeast Utilities (NYSE-NU)	3.3%	3.3%	3.7%	3.3%	3.6%	3.5%	3.5%
NorthWestern Corporation (NYSE-NWE)	3.7%	3.6%	4.0%	3.5%	3.8%	3.5%	3.7%
OGE Energy Corp. (NYSE-OGE)	2.4%	2.3%	2.6%	2.3%	2.4%	2.3%	2.4%
Otter Tail Corporation (NDQ-OTTR)	3.9%	4.0%	4.4%	3.7%	4.4%	4.2%	4.1%
Pepco Holdings, Inc. (NYSE-POM)	5.0%	4.9%	5.6%	5.3%	5.7%	5.8%	5.4%
Pinnacle West Capital Corp. (NYSE-PNW)	3.6%	3.6%	4.2%	3.6%	4.0%	3.9%	3.8%
PNM Resources, Inc. (NYSE-PNM)	2.8%	2.9%	3.1%	2.8%	2.9%	2.9%	2.9%
Portland General Electric (NYSE-POR)	3.5%	3.3%	3.7%	3.4%	3.9%	3.8%	3.6%
SCANA Corporation (NYSE-SCG)	3.9%	3.8%	4.3%	3.9%	4.2%	4.3%	4.1%
SEMPRA Energy (NYSE-SRE)	3.1%	3.0%	3.2%	2.9%	3.1%	2.9%	3.0%
Southern Company (NYSE-SO)	4.0%	4.4%	4.8%	4.5%	4.8%	4.8%	4.6%
TECO Energy (NYSE-TE)	4.8%	4.6%	5.3%	4.9%	5.3%	5.2%	5.0%
Vectren Corporation (NYSE-VVC)	3.9%	3.9%	4.4%	3.9%	4.2%	4.2%	4.1%
Westar Energy, Inc. (NYSE-WR)	4.0%	4.0%	4.5%	4.0%	4.3%	4.5%	4.2%
Wisconsin Energy Corporation (NYSE-WEC)	3.1%	3.1%	3.5%	3.1%	3.7%	3.7%	3.4%
Xcel Energy Inc. (NYSE-XEL)	3.5%	3.6%	4.0%	3.7%	4.0%	4.0%	3.8%
Mean	3.7%	3.7%	4.1%	3.7%	4.0%	4.0%	3.9%
Median	3.7%	3.6%	4.1%	3.7%	4.0%	3.9%	3.8%

Data Source: AUS Utilities Report, Monthly issues

Company	Annual Dividend	Dividend Yield 30 Day	Dividend Yield 60 Day	Dividend Yield 90 Day
ALLETE, Inc. (NYSE-ALE)	1.90	4.00%	3.85%	3.87%
Alliant Energy Corporation (NYSE-LNT)	1.88	3.80%	3.69%	3.73%
American Electric Power Co. (NYSE-AEP)	1.96	4.54%	4.44%	4.42%
Black Hills Corporation (NYSE-BKH)	1.52	3.12%	3.02%	3.06%
CenterPoint Energy (NYSE-CNP)	0.83	3.53%	3.49%	3.52%
CMS Energy Corporation (NYSE-CMS)	1.02	3.88%	3.77%	3.79%
Dominion Resources, Inc. (NYSE-D)	2.25	3.72%	3.78%	3.86%
DTE Energy Company (NYSE-DTE)	2.62	3.96%	3.88%	3.91%
Duke Energy Corporation (NYSE-DUK)	3.12	4.70%	4.60%	4.63%
Entergy Corporation (NYSE-ETR)	3.32	5.24%	5.07%	5.00%
Great Plains Energy Incorporated (NYSE-GXP)	0.87	3.95%	3.81%	3.83%
Hawaiian Electric Industries, Inc. (NYSE-HE)	1.24	4.97%	4.85%	4.90%
Integrys Energy Group (NYSE-TEG)	2.72	4.90%	4.69%	4.72%
Nextera Energy (NYSE-NEE)	2.64	3.29%	3.21%	3.26%
Northeast Utilities (NYSE-NU)	1.47	3.60%	3.50%	3.52%
NorthWestern Corporation (NYSE-NWE)	1.52	3.59%	3.62%	3.68%
OGE Energy Corp. (NYSE-OGE)	0.84	2.36%	2.31%	2.37%
Otter Tail Corporation (NDQ-OTTR)	1.19	4.36%	4.18%	4.20%
Pepco Holdings, Inc. (NYSE-POM)	1.08	5.86%	5.65%	5.59%
Pinnacle West Capital Corp. (NYSE-PNW)	2.18	4.02%	3.90%	3.91%
PNM Resources, Inc. (NYSE-PNM)	0.66	2.99%	2.90%	2.93%
Portland General Electric (NYSE-POR)	1.30	4.61%	4.43%	4.39%
SCANA Corporation (NYSE-SCG)	2.03	4.36%	4.18%	4.18%
SEMPRA Energy (NYSE-SRE)	2.52	2.97%	2.96%	3.03%
Southern Company (NYSE-SO)	2.03	4.91%	4.76%	4.73%
TECO Energy (NYSE-TE)	0.88	5.30%	5.19%	5.19%
Vectren Corporation (NYSE-VVC)	1.42	4.31%	4.15%	4.18%
Westar Energy, Inc. (NYSE-WR)	1.36	4.46%	4.30%	4.32%
Wisconsin Energy Corporation (NYSE-WEC)	1.53	3.78%	3.69%	3.72%
Xcel Energy Inc. (NYSE-XEL)	1.12	4.07%	3.96%	3.96%
Mean		4.1%	4.0%	4.0%
Median		4.0%	3.9%	3.9%

Data Source: AUS Utilities Report, www.yahoo.com

Summary Dividend Yields

	Dividend Yield 6 Month	Dividend Yield 30 Day	Dividend Yield 60 Day	Dividend Yield 90 Day
Mean	3.9%	4.1%	4.0%	4.0%
Median	3.8%	4.0%	3.9%	3.9%

Exhibit JRW-10

Gulf Power Company
DCF Equity Cost Growth Rate Measures
***Value Line* Historic Growth Rates**

Electric Proxy Group

Company	*Value Line* Historic Growth					
	Past 10 Years			Past 5 Years		
	Earnings	Dividends	Book Value	Earnings	Dividends	Book Value
ALLETE, Inc. (NYSE-ALE)				-2.5%	4.5%	5.5%
Alliant Energy Corporation (NYSE-LNT)	3.5%	-1.5%	2.0%	4.0%	8.0%	3.5%
Ameren Corporation (NYSE-AEE)	-2.0%	-4.5%	2.5%	-2.5%	-9.0%	-0.5%
American Electric Power Co. (NYSE-AEP)	2.0%	-3.0%	2.5%	1.0%	4.0%	4.5%
Avista Corporation (NYSE-AVA)	2.5%	8.5%	3.0%	8.5%	14.0%	4.0%
Black Hills Corporation (NYSE-BKH)	-5.5%	2.5%	5.0%	-8.0%	2.0%	3.0%
Cleco Corporation (NYSE-CNL)	5.5%	2.5%	8.0%	13.0%	4.5%	9.0%
CMS Energy Corporation (NYSE-CMS)	18.0%	-5.0%	-1.5%	12.5%		3.0%
Consolidated Edison, Inc. (NYSE-ED)	2.0%	1.0%	4.0%	3.0%	1.0%	4.5%
DTE Energy Company (NYSE-DTE)	2.0%	1.0%	4.0%	6.0%	2.0%	4.0%
Duke Energy Corporation (NYSE-DUK)				4.5%	18.0%	-1.0%
Edison International (NYSE-EIX)		.	11.5%	2.5%	3.0%	5.5%
FirstEnergy Corporation (ASE-FE)	-1.0%	4.0%	2.5%	-8.0%	3.5%	1.0%
Great Plains Energy Incorporated (NYSE-GXP)	-3.0%	-6.5%	4.5%	-6.0%	-12.5%	5.0%
Hawaiian Electric Industries, Inc. (NYSE-HE)	-0.5%		2.0%	2.0%		2.0%
IDACORP, Inc. (NYSE-IDA)	1.5%	-4.0%	4.0%	10.0%	1.0%	5.5%
MGE Energy (NDQ-MGEE)	5.0%	1.5%	6.5%	6.0%	2.0%	5.5%
Nextera Energy (NYSE-NEE)	8.5%	7.0%	8.0%	10.0%	7.5%	8.5%
Northeast Utilities (NYSE-NU)	10.5%	9.5%	4.0%	13.0%	9.5%	6.0%
NorthWestern Corporation (NYSE-NWE)				9.0%	4.0%	2.5%
Otter Tail Corporation (NDQ-OTTR)	-9.5%	1.5%	3.5%	-18.5%	0.5%	-1.0%
Pepco Holdings, Inc. (NYSE-POM)	-4.0%		0.5%	-3.5%	1.0%	
PG&E Corporation (NYSE-PCG)			11.5%	-0.5%	6.5%	6.0%
Pinnacle West Capital Corp. (NYSE-PNW)		4.0%	2.0%	2.5%	2.5%	
PNM Resources, Inc. (NYSE-PNM)	-4.5%	-0.5%	1.5%	-4.0%	-9.0%	-2.0%
Portland General Electric (NYSE-POR)				4.0%	14.5%	2.0%
PPL Corporation (NYSE-PPL)	4.0%	9.0%	10.5%	2.0%	5.5%	6.0%
SCANA Corporation (NYSE-SCG)	3.0%	5.0%	4.0%	2.5%	3.0%	4.5%
Southern Company (NYSE-SO)	3.5%	3.5%	4.5%	3.0%	4.0%	5.5%
UNS Energy Corp. (NYSE-UNS)	7.0%	15.0%	7.0%	10.5%	14.5%	5.5%
Westar Energy, Inc. (NYSE-WR)	16.0%			1.5%	5.0%	4.5%
Wisconsin Energy Corporation (NYSE-WEC)	9.5%	7.5%	7.0%	10.0%	17.0%	7.0%
Xcel Energy Inc. (NYSE-XEL)	2.0%	-3.0%	1.5%	5.5%	3.0%	4.5%
Mean	2.9%	2.3%	4.5%	2.8%	4.4%	4.0%
Median	2.3%	2.0%	4.0%	3.0%	4.0%	4.5%
Data Source: *Value Line Investment Survey.*	Average of Median Figures =			3.3%		

Exhibit JRW-10

Gulf Power Company
DCF Equity Cost Growth Rate Measures
***Value Line* Historic Growth Rates**

Vander Weide Proxy Group

Company	*Value Line* Historic Growth					
	Past 10 Years			Past 5 Years		
	Earnings	Dividends	Book Value	Earnings	Dividends	Book Value
ALLETE, Inc. (NYSE-ALE)				-2.5%	4.5%	5.5%
Alliant Energy Corporation (NYSE-LNT)	3.5%	-1.5%	2.0%	4.0%	8.0%	3.5%
American Electric Power Co. (NYSE-AEP)	2.0%	-3.0%	2.5%	1.0%	4.0%	4.5%
Black Hills Corporation (NYSE-BKH)	-5.5%	2.5%	5.0%	-8.0%	2.0%	3.0%
CenterPoint Energy (NYSE-CNP)	-1.5%	-4.5%	-4.0%	3.0%	7.0%	13.5%
CMS Energy Corporation (NYSE-CMS)	18.0%	-5.0%	-1.5%	12.5%		3.0%
Dominion Resources, Inc. (NYSE-D)	5.0%	4.5%	2.5%	7.0%	7.0%	3.5%
DTE Energy Company (NYSE-DTE)	2.0%	1.0%	4.0%	6.0%	2.0%	4.0%
Duke Energy Corporation (NYSE-DUK)				4.5%	18.0%	-1.0%
Entergy Corporation (NYSE-ETR)	7.5%	10.0%	4.0%	5.5%	7.5%	5.0%
Great Plains Energy Incorporated (NYSE-GXP)	-3.0%	-6.5%	4.5%	-6.0%	-12.5%	5.0%
Hawaiian Electric Industries, Inc. (NYSE-HE)	-0.5%		2.0%	2.0%		2.0%
Integrys Energy Group (NYSE-TEG)	2.0%	2.5%	5.5%	-0.5%	3.0%	0.5%
Nextera Energy (NYSE-NEE)	8.5%	7.0%	8.0%	10.0%	7.5%	8.5%
Northeast Utilities (NYSE-NU)	10.5%	9.5%	4.0%	13.0%	9.5%	6.0%
NorthWestern Corporation (NYSE-NWE)				9.0%	4.0%	2.5%
OGE Energy Corp. (NYSE-OGE)	8.0%	1.5%	7.0%	7.5%	2.5%	8.5%
Otter Tail Corporation (NDQ-OTTR)	-9.5%	1.5%	3.5%	-18.5%	0.5%	-1.0%
Pepco Holdings, Inc. (NYSE-POM)	-4.0%		0.5%	-3.5%	1.0%	
Pinnacle West Capital Corp. (NYSE-PNW)		4.0%	2.0%	2.5%	2.5%	
PNM Resources, Inc. (NYSE-PNM)	-4.5%	-0.5%	1.5%	-4.0%	-9.0%	-2.0%
Portland General Electric (NYSE-POR)				4.0%	14.5%	2.0%
SCANA Corporation (NYSE-SCG)	3.0%	5.0%	4.0%	2.5%	3.0%	4.5%
SEMPRA Energy (NYSE-SRE)	5.5%	7.0%	12.0%	1.5%	10.5%	7.5%
Southern Company (NYSE-SO)	3.5%	3.5%	4.5%	3.0%	4.0%	5.5%
TECO Energy (NYSE-TE)	-5.5%	-4.5%	-3.5%	0.5%	2.0%	4.0%
Vectren Corporation (NYSE-VVC)	3.0%	3.0%	4.0%	1.0%	2.5%	3.0%
Westar Energy, Inc. (NYSE-WR)	16.0%			1.5%	5.0%	4.5%
Wisconsin Energy Corporation (NYSE-WEC)	9.5%	7.5%	7.0%	10.0%	17.0%	7.0%
Xcel Energy Inc. (NYSE-XEL)	2.0%	-3.0%	1.5%	5.5%	3.0%	4.5%
Mean	3.0%	1.8%	3.3%	2.5%	4.7%	4.2%
Median	3.0%	2.5%	4.0%	2.8%	4.0%	4.3%
Data Source: *Value Line Investment Survey.*	Average of Median Figures =			3.4%		

Exhibit JRW-10

Gulf Power Company
DCF Equity Cost Growth Rate Measures
Value Line Projected Growth Rates

Electric Proxy Group

Company	*Value Line* Projected Growth Est'd. '10-'12 to '16-'18			*Value Line* Sustainable Growth		
	Earnings	Dividends	Book Value	Return on Equity	Retention Rate	Internal Growth
ALLETE, Inc. (NYSE-ALE)	7.0%	3.5%	4.0%	10.0%	39.0%	3.9%
Alliant Energy Corporation (NYSE-LNT)	6.0%	4.5%	4.0%	11.5%	42.0%	4.8%
Ameren Corporation (NYSE-AEE)	-0.5%	1.5%	-0.5%	8.5%	33.0%	2.8%
American Electric Power Co. (NYSE-AEP)	4.5%	4.0%	4.0%	10.0%	39.0%	3.9%
Avista Corporation (NYSE-AVA)	4.0%	4.5%	3.0%	8.5%	34.0%	2.9%
Black Hills Corporation (NYSE-BKH)	11.5%	2.5%	3.0%	9.5%	45.0%	4.3%
Cleco Corporation (NYSE-CNL)	5.5%	10.0%	5.0%	11.0%	43.0%	4.7%
CMS Energy Corporation (NYSE-CMS)	5.5%	8.0%	5.5%	13.0%	38.0%	4.9%
Consolidated Edison, Inc. (NYSE-ED)	2.5%	1.5%	3.5%	9.0%	39.0%	3.5%
DTE Energy Company (NYSE-DTE)	4.0%	5.5%	4.0%	9.0%	36.0%	3.2%
Duke Energy Corporation (NYSE-DUK)	4.0%	2.0%	3.0%	8.0%	33.0%	2.6%
Edison International (NYSE-EIX)	1.5%	5.5%	3.5%	10.5%	50.0%	5.3%
FirstEnergy Corporation (ASE-FE)	0.5%	0.0%	1.5%	7.5%	13.0%	1.0%
Great Plains Energy Incorporated (NYSE-GXP)	6.5%	6.0%	2.5%	8.0%	39.0%	3.1%
Hawaiian Electric Industries, Inc. (NYSE-HE)	3.5%	1.0%	4.5%	8.0%	22.0%	1.8%
IDACORP, Inc. (NYSE-IDA)	2.0%	7.0%	4.5%	8.5%	48.0%	4.1%
MGE Energy (NDQ-MGEE)	5.5%	3.5%	5.0%	11.5%	49.0%	5.6%
Nextera Energy (NYSE-NEE)	5.5%	8.5%	6.5%	12.5%	45.0%	5.6%
Northeast Utilities (NYSE-NU)	8.0%	8.0%	6.0%	9.5%	45.0%	4.3%
NorthWestern Corporation (NYSE-NWE)	4.5%	4.0%	4.5%	9.5%	39.0%	3.7%
Otter Tail Corporation (NDQ-OTTR)	21.5%	1.5%	2.0%	11.0%	34.0%	3.7%
Pepco Holdings, Inc. (NYSE-POM)	6.0%	1.0%	2.0%	8.0%	31.0%	2.5%
PG&E Corporation (NYSE-PCG)	2.5%	2.5%	3.0%	8.5%	31.0%	2.6%
Pinnacle West Capital Corp. (NYSE-PNW)	5.0%	2.0%	3.5%	10.0%	40.0%	4.0%
PNM Resources, Inc. (NYSE-PNM)	12.0%	12.5%	3.5%	9.0%	49.0%	4.4%
Portland General Electric (NYSE-POR)	3.5%	3.0%	3.5%	8.0%	42.0%	3.4%
PPL Corporation (NYSE-PPL)	0.0%	2.0%	4.5%	10.5%	35.0%	3.7%
SCANA Corporation (NYSE-SCG)	4.5%	2.5%	5.0%	9.5%	43.0%	4.1%
Southern Company (NYSE-SO)	4.5%	3.5%	4.0%	12.5%	28.0%	3.5%
UNS Energy Corp. (NYSE-UNS)	6.5%	5.5%	5.0%	11.5%	39.0%	4.5%
Westar Energy, Inc. (NYSE-WR)	6.0%	3.0%	5.0%	9.0%	45.0%	4.1%
Wisconsin Energy Corporation (NYSE-WEC)	5.5%	12.0%	3.5%	14.5%	35.0%	5.1%
Xcel Energy Inc. (NYSE-XEL)	4.5%	4.5%	4.5%	10.0%	42.0%	4.2%
Mean	5.3%	4.4%	3.8%	9.9%	38.3%	3.8%
Median	4.5%	3.5%	4.0%	9.5%	39.0%	3.9%
Average of Median Figures =		4.0%				3.9%

Data Source: *Value Line Investment Survey.*

Exhibit JRW-10

Gulf Power Company
DCF Equity Cost Growth Rate Measures
Value Line Projected Growth Rates

Vander Weide Proxy Group

Company	*Value Line* Projected Growth Est'd. '10-'12 to '16-'18			*Value Line* Sustainable Growth		
	Earnings	Dividends	Book Value	Return on Equity	Retention Rate	Internal Growth
ALLETE, Inc. (NYSE-ALE)	7.0%	3.5%	4.0%	10.0%	39.0%	3.9%
Alliant Energy Corporation (NYSE-LNT)	6.0%	4.5%	4.0%	11.5%	42.0%	4.8%
American Electric Power Co. (NYSE-AEP)	4.5%	4.0%	4.0%	10.0%	39.0%	3.9%
Black Hills Corporation (NYSE-BKH)	11.5%	2.5%	3.0%	9.5%	45.0%	4.3%
CenterPoint Energy (NYSE-CNP)	6.0%	4.0%	5.0%	14.5%	43.0%	6.2%
CMS Energy Corporation (NYSE-CMS)	5.5%	8.0%	5.5%	13.0%	38.0%	4.9%
Dominion Resources, Inc. (NYSE-D)	5.0%	5.5%	4.5%	14.5%	28.0%	4.1%
DTE Energy Company (NYSE-DTE)	4.0%	5.5%	4.0%	9.0%	36.0%	3.2%
Duke Energy Corporation (NYSE-DUK)	4.0%	2.0%	3.0%	8.0%	33.0%	2.6%
Entergy Corporation (NYSE-ETR)	-4.0%	0.5%	2.0%	9.5%	36.0%	3.4%
Great Plains Energy Incorporated (NYSE-GXP)	6.5%	6.0%	2.5%	8.0%	39.0%	3.1%
Hawaiian Electric Industries, Inc. (NYSE-HE)	3.5%	1.0%	4.5%	8.0%	22.0%	1.8%
Integrys Energy Group (NYSE-TEG)	4.5%	1.0%	5.0%	8.5%	32.0%	2.7%
Nextera Energy (NYSE-NEE)	5.5%	8.5%	6.5%	12.5%	45.0%	5.6%
Northeast Utilities (NYSE-NU)	8.0%	8.0%	6.0%	9.5%	45.0%	4.3%
NorthWestern Corporation (NYSE-NWE)	4.5%	4.0%	4.5%	9.5%	39.0%	3.7%
OGE Energy Corp. (NYSE-OGE)	5.0%	8.5%	7.0%	12.0%	47.0%	5.6%
Otter Tail Corporation (NDQ-OTTR)	21.5%	1.5%	2.0%	11.0%	34.0%	3.7%
Pepco Holdings, Inc. (NYSE-POM)	6.0%	1.0%	2.0%	8.0%	31.0%	2.5%
Pinnacle West Capital Corp. (NYSE-PNW)	5.0%	2.0%	3.5%	10.0%	40.0%	4.0%
PNM Resources, Inc. (NYSE-PNM)	12.0%	12.5%	3.5%	9.0%	49.0%	4.4%
Portland General Electric (NYSE-POR)	3.5%	3.0%	3.5%	8.0%	42.0%	3.4%
SCANA Corporation (NYSE-SCG)	4.5%	2.5%	5.0%	9.5%	43.0%	4.1%
SEMPRA Energy (NYSE-SRE)	4.5%	7.5%	4.5%	11.0%	46.0%	5.1%
Southern Company (NYSE-SO)	4.5%	3.5%	4.0%	12.5%	28.0%	3.5%
TECO Energy (NYSE-TE)	3.0%	2.0%	2.0%	12.0%	31.0%	3.7%
Vectren Corporation (NYSE-VVC)	7.5%	2.5%	4.0%	11.5%	39.0%	4.5%
Westar Energy, Inc. (NYSE-WR)	6.0%	3.0%	5.0%	9.0%	45.0%	4.1%
Wisconsin Energy Corporation (NYSE-WEC)	5.5%	12.0%	3.5%	14.5%	35.0%	5.1%
Xcel Energy Inc. (NYSE-XEL)	4.5%	4.5%	4.5%	10.0%	42.0%	4.2%
Mean	5.8%	4.5%	4.1%	10.5%	38.4%	4.0%
Median	5.0%	3.8%	4.0%	10.0%	39.0%	4.0%
Average of Median Figures =		4.3%				4.0%

Data Source: *Value Line Investment Survey.*

Exhibit JRW-10

Gulf Power Company
DCF Equity Cost Growth Rate Measures
Analysts Projected EPS Growth Rate Estimates

Electric Proxy Group

Company	Yahoo	Zacks	Reuters	Mean
ALLETE, Inc. (NYSE-ALE)	6.0%	6.0%	6.0%	6.0%
Alliant Energy Corporation (NYSE-LNT)	4.8%	5.3%	5.4%	5.2%
Ameren Corporation (NYSE-AEE)	2.1%	2.7%	2.1%	2.3%
American Electric Power Co. (NYSE-AEP)	4.1%	3.9%	4.1%	4.0%
Avista Corporation (NYSE-AVA)	5.0%	5.0%	5.0%	5.0%
Black Hills Corporation (NYSE-BKH)	4.0%	4.0%	4.0%	4.0%
Cleco Corporation (NYSE-CNL)	8.0%	8.0%	n/a	8.0%
CMS Energy Corporation (NYSE-CMS)	5.9%	5.8%	5.9%	5.8%
Consolidated Edison, Inc. (NYSE-ED)	1.8%	3.0%	1.8%	2.2%
DTE Energy Company (NYSE-DTE)	4.6%	4.6%	4.6%	4.6%
Duke Energy Corporation (NYSE-DUK)	3.7%	3.7%	3.9%	3.7%
Edison International (NYSE-EIX)	0.8%	1.4%	1.5%	1.2%
FirstEnergy Corporation (ASE-FE)	1.9%	0.0%	2.1%	1.4%
Great Plains Energy Incorporated (NYSE-GXP)	6.4%	6.5%	6.4%	6.4%
Hawaiian Electric Industries, Inc. (NYSE-HE)	2.4%	2.4%	3.7%	2.8%
IDACORP, Inc. (NYSE-IDA)	4.0%	4.0%	n/a	4.0%
MGE Energy (NDQ-MGEE)	4.0%	n/a	n/a	4.0%
Nextera Energy (NYSE-NEE)	6.4%	6.2%	6.1%	6.2%
Northeast Utilities (NYSE-NU)	7.6%	7.9%	7.2%	7.6%
NorthWestern Corporation (NYSE-NWE)	4.0%	4.5%	n/a	4.3%
Otter Tail Corporation (NDQ-OTTR)	6.0%	n/a	n/a	6.0%
Pepco Holdings, Inc. (NYSE-POM)	3.8%	5.0%	3.8%	4.2%
PG&E Corporation (NYSE-PCG)	2.8%	3.9%	3.6%	3.4%
Pinnacle West Capital Corp. (NYSE-PNW)	4.7%	4.6%	4.7%	4.7%
PNM Resources, Inc. (NYSE-PNM)	6.4%	7.8%	6.4%	6.9%
Portland General Electric Company (NYSE-POR)	6.5%	5.9%	6.2%	6.2%
PPL Corporation (NYSE-PPL)	1.7%	-3.0%	1.7%	0.1%
SCANA Corporation (NYSE-SCG)	4.8%	4.7%	4.8%	4.8%
Southern Company (NYSE-SO)	4.3%	4.4%	4.5%	4.4%
UNS Energy Corp. (NYSE-UNS)	8.0%	7.0%	n/a	7.5%
Westar Energy, Inc. (NYSE-WR)	1.9%	3.6%	1.9%	2.4%
Wisconsin Energy Corporation (NYSE-WEC)	5.2%	5.4%	5.2%	5.3%
Xcel Energy Inc. (NYSE-XEL)	4.9%	4.3%	5.5%	4.9%
Mean	4.5%	4.5%	4.4%	4.5%
Median	4.6%	4.6%	4.6%	4.6%

Data Sources: www.reuters.com, www.zacks.com, http://quote.yahoo.com, September 30, 2013.

Exhibit JRW-10

Gulf Power Company
DCF Equity Cost Growth Rate Measures
Analysts Projected EPS Growth Rate Estimates

Vander Weide Proxy Group

Company	Yahoo	Zacks	Reuters	Mean
ALLETE, Inc. (NYSE-ALE)	6.0%	6.0%	6.0%	6.0%
Alliant Energy Corporation (NYSE-LNT)	4.8%	5.3%	5.4%	5.2%
American Electric Power Co. (NYSE-AEP)	4.1%	3.9%	4.1%	4.0%
Black Hills Corporation (NYSE-BKH)	4.0%	4.0%	4.0%	4.0%
CenterPoint Energy (NYSE-CNP)	4.5%	5.1%	4.5%	4.7%
CMS Energy Corporation (NYSE-CMS)	5.9%	5.8%	5.9%	5.8%
Dominion Resources, Inc. (NYSE-D)	6.9%	5.8%	6.7%	6.5%
DTE Energy Company (NYSE-DTE)	4.6%	4.6%	4.6%	4.6%
Duke Energy Corporation (NYSE-DUK)	3.7%	3.7%	3.9%	3.7%
Entergy Corporation (NYSE-ETR)	-3.8%	na	-0.9%	-2.3%
Great Plains Energy Incorporated (NYSE-GXP)	6.4%	6.5%	6.4%	6.4%
Hawaiian Electric Industries, Inc. (NYSE-HE)	2.4%	2.4%	3.7%	2.8%
Integrys Energy Group (NYSE-TEG)	5.0%	5.0%	5.0%	5.0%
Nextera Energy (NYSE-NEE)	6.4%	6.2%	6.1%	6.2%
Northeast Utilities (NYSE-NU)	7.6%	7.9%	7.2%	7.6%
NorthWestern Corporation (NYSE-NWE)	4.0%	4.5%	n/a	4.3%
OGE Energy Corp. (NYSE-OGE)	4.6%	5.5%	4.6%	4.9%
Otter Tail Corporation (NDQ-OTTR)	6.0%	n/a	n/a	6.0%
Pepco Holdings, Inc. (NYSE-POM)	3.8%	5.0%	3.8%	4.2%
Pinnacle West Capital Corp. (NYSE-PNW)	4.7%	4.6%	4.7%	4.7%
PNM Resources, Inc. (NYSE-PNM)	6.4%	7.8%	6.4%	6.9%
Portland General Electric (NYSE-POR)	6.5%	5.9%	6.2%	6.2%
SCANA Corporation (NYSE-SCG)	4.8%	4.7%	4.8%	4.8%
SEMPRA Energy (NYSE-SRE)	2.9%	5.0%	2.9%	3.6%
Southern Company (NYSE-SO)	4.3%	4.4%	4.5%	4.4%
TECO Energy (NYSE-TE)	2.8%	5.0%	2.8%	3.6%
Vectren Corporation (NYSE-VVC)	5.0%	5.0%	n/a	5.0%
Westar Energy, Inc. (NYSE-WR)	1.9%	3.6%	1.9%	2.4%
Wisconsin Energy Corporation (NYSE-WEC)	5.2%	5.4%	5.2%	5.3%
Xcel Energy Inc. (NYSE-XEL)	4.9%	4.3%	5.5%	4.9%
Mean	4.5%	5.1%	4.7%	4.7%
Median	4.7%	5.0%	4.7%	4.8%

Data Sources: www.reuters.com, www.zacks.com, http://quote.yahoo.com, September 30, 2013.

Exhibit JRW-10

Gulf Power Company
DCF Growth Rate Indicators

Summary Growth Rates

Growth Rate Indicator	Electric Proxy Group	Vander Weide Proxy Group
Historic *Value Line* Growth in EPS, DPS, and BVPS	3.3%	3.4%
Projected *Value Line* Growth in EPS, DPS, and BVPS	4.0%	4.3%
Sustainable Growth ROE * Retention Rate	3.9%	4.0%
Projected EPS Growth from Yahoo, Zacks, and Reuters	4.6%	4.8%
Average of Historic and Projected Growth Rates	4.0%	4.1%
Average of Sustainable and Projected Growth Rates	4.2%	4.4%

Exhibit JRW-11

Gulf Power Company
Capital Asset Pricing Model

Electric Proxy Group

Risk-Free Interest Rate	**4.00%**
Beta*	**0.70**
Ex Ante Equity Risk Premium**	**5.00%**
CAPM Cost of Equity	**7.5%**

* See page 3 of Exhibit JRW-11
** See pages 5 and 6 of Exhibit JRW-11

Vander Weide Proxy Group

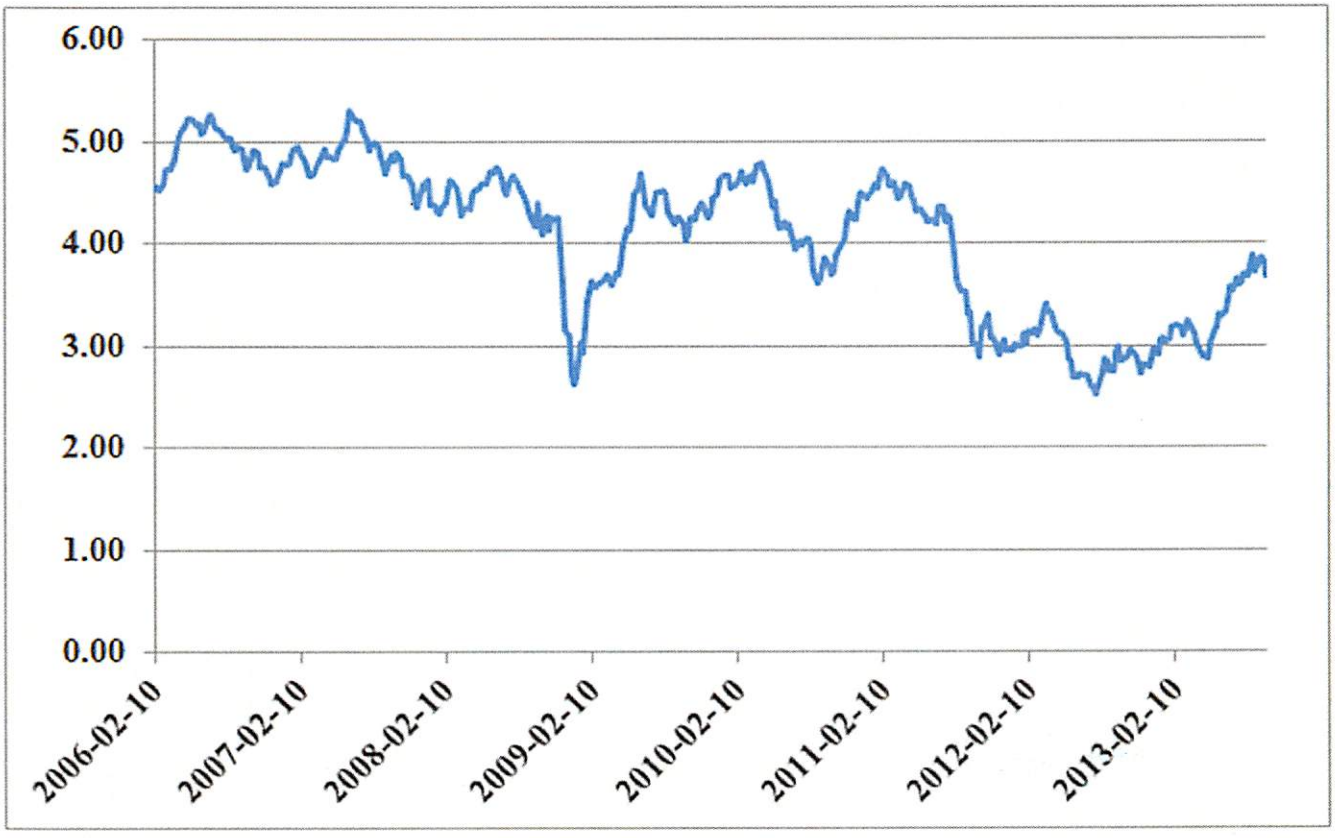
Risk-Free Interest Rate	**4.00%**
Beta*	**0.75**
Ex Ante Equity Risk Premium**	**5.00%**
CAPM Cost of Equity	**7.8%**

* See page 3 of Exhibit JRW-11
** See pages 5 and 6 of Exhibit JRW-11

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130140-EI EXHIBIT 55
PARTY Office of Public Counsel (OPC) Direct
DESCRIPTION Randall Woodridge (JRW-11)
DATE

Exhibit JRW-11

30-Year U.S. Treasury Yields
January 2006-Present

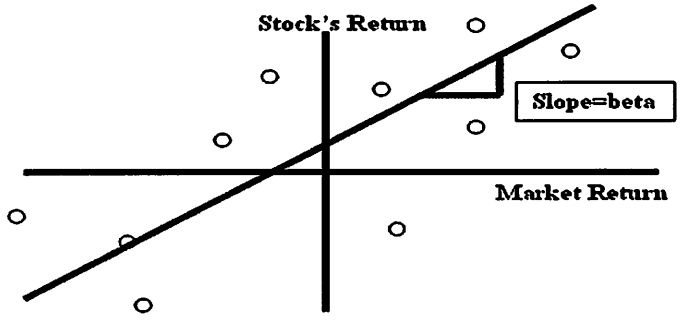


Source: Federal Reserve Bank of St. Louis, FRED Database.

Exhibit JRW-11

Betas

Calculation of Beta



Panel A
Electric Proxy Group

Company Name	Beta
ALLETE, Inc. (NYSE-ALE)	0.70
Alliant Energy Corporation (NYSE-LNT)	0.75
Ameren Corporation (NYSE-AEE)	0.80
American Electric Power Co. (NYSE-AEP)	0.70
Avista Corporation (NYSE-AVA)	0.70
Black Hills Corporation (NYSE-BKH)	0.80
Cleco Corporation (NYSE-CNL)	0.65
CMS Energy Corporation (NYSE-CMS)	0.75
Consolidated Edison, Inc. (NYSE-ED)	0.60
DTE Energy Company (NYSE-DTE)	0.75
Duke Energy Corporation (NYSE-DUK)	0.60
Edison International (NYSE-EIX)	0.75
FirstEnergy Corporation (ASE-FE)	0.80
Great Plains Energy Incorporated (NYSE-GXP)	0.80
Hawaiian Electric Industries, Inc. (NYSE-HE)	0.70
IDACORP, Inc. (NYSE-IDA)	0.70
MGE Energy, Inc. (NYSE-MGEE)	0.60
Nextera Energy (NYSE-NEE)	0.70
Northeast Utilities (NYSE-NU)	0.75
NorthWestern Corporation (NYSE-NWE)	0.70
Otter Tail Corporation (NDQ-OTTR)	0.90
Pepco Holdings, Inc. (NYSE-POM)	0.75
PG&E Corporation (NYSE-PCG)	0.55
Pinnacle West Capital Corp. (NYSE-PNW)	0.70
PNM Resources, Inc. (NYSE-PNM)	0.95
Portland General Electric Company (NYSE-POI	0.75
PPL Corporation (NYSE-PPL)	0.65
SCANA Corporation (NYSE-SCG)	0.65
Southern Company (NYSE-SO)	0.55
UNS Energy Corp. (NYSE-UNS)	0.70
Westar Energy, Inc. (NYSE-WR)	0.75
Wisconsin Energy Corporation (NYSE-WEC)	0.65
Xcel Energy Inc. (NYSE-XEL)	0.60
Mean	0.71
Median	0.70

Data Source: *Value Line Investment Survey, 2013.*

Panel B
Vander Weide Proxy Group

Company Name	Beta
ALLETE, Inc. (NYSE-ALE)	0.70
Alliant Energy Corporation (NYSE-LNT)	0.75
American Electric Power Co. (NYSE-AEP)	0.70
Black Hills Corporation (NYSE-BKH)	0.80
CenterPoint Energy (NYSE-CNP)	0.80
CMS Energy Corporation (NYSE-CMS)	0.75
Dominion Resources, Inc. (NYSE-D)	0.70
DTE Energy Company (NYSE-DTE)	0.75
Duke Energy Corporation (NYSE-DUK)	0.60
Entergy Corporation (NYSE-ETR)	0.70
Great Plains Energy Incorporated (NYSE-GXP)	0.80
Hawaiian Electric Industries, Inc. (NYSE-HE)	0.70
Integrys Energy Group (NYSE-TEG)	0.90
Nextera Energy (NYSE-NEE)	0.70
Northeast Utilities (NYSE-NU)	0.75
NorthWestern Corporation (NYSE-NWE)	0.70
OGE Energy Corp. (NYSE-OGE)	0.75
Otter Tail Corporation (NDQ-OTTR)	0.90
Pepco Holdings, Inc. (NYSE-POM)	0.75
Pinnacle West Capital Corp. (NYSE-PNW)	0.70
PNM Resources, Inc. (NYSE-PNM)	0.95
Portland General Electric Company (NYSE-POR	0.75
SCANA Corporation (NYSE-SCG)	0.65
SEMPRA Energy (NYSE-SRE)	0.80
Southern Company (NYSE-SO)	0.55
TECO Energy (NYSE-TE)	0.85
Vectren Corporation (NYSE-VVC)	0.75
Westar Energy, Inc. (NYSE-WR)	0.75
Wisconsin Energy Corporation (NYSE-WEC)	0.65
Xcel Energy Inc. (NYSE-XEL)	0.60
Mean	0.74
Median	0.75

Data Source: *Value Line Investment Survey, 2013.*

Exhibit JRW-11
Risk Premium Approaches

	Historical Ex Post Returns	**Surveys**	**Expected Return Models and Market Data**
Means of Assessing The Market Risk Premium	Historical Average Stock Minus Bond Returns	Surveys of CFOs, Financial Forecasters, Companies, Analysts on Expected Returns and Market Risk Premiums	Use Market Prices and Market Fundamentals (such as Growth Rates) to Compute Expected Returns and Market Risk Premiums
Problems/Debated Issues	Time Variation in Required Returns, Measurement and Time Period Issues, and Biases such as Market and Company Survivorship Bias	Questions Regarding Survey Histories, Responses, and Representativeness Surveys may be Subject to Biases, such as Extrapolation	Assumptions Regarding Expectations, Especially Growth

Source: Adapted from Antti Ilmanen, Expected Returns on Stocks and Bonds," *Journal of Portfolio Management*, (Winter 2003).

Exhibit JRW-11

Gulf Power Company
Capital Asset Pricing Model
Equity Risk Premium

Category	Study Authors	Publication Date	Time Period Of Study	Methodology	Return Measure	Range Low	Range High	Midpoint of Range	Mean	Median
Historical Risk Premium										
	Ibbotson	2013	1926-2012	Historical Stock Returns - Bond Returns	Arithmetic				5.70%	
					Geometric				4.10%	
	Damodaran	2013	1928-2012	Historical Stock Returns - Bond Returns	Arithmetic				5.88%	
					Geometric				4.20%	
	Dimson, Marsh, Staunton	2013	1900-2012	Historical Stock Returns - Bond Returns	Arithmetic					
					Geometric				4.20%	
	Bate	2008	1900-2007	Historical Stock Returns - Bond Returns	Geometric				4.50%	
	Shiller	2006	1926-2005	Historical Stock Returns - Bond Returns	Arithmetic				7.00%	
					Geometric				5.50%	
	Siegel	2005	1926-2005	Historical Stock Returns - Bond Returns	Arithmetic				6.10%	
					Geometric				4.60%	
	Dimson, Marsh, and Staunton	2006	1900-2005	Historical Stock Returns - Bond Returns	Arithmetic				5.50%	
	Goyal & Welch	2006	1872-2004	Historical Stock Returns - Bond Returns					4.77%	
	Median									5.14%
Ex Ante Models (Puzzle Research)										
	Claus Thomas	2001	1985-1998	Abnormal Earnings Model					3.00%	
	Arnott and Bernstein	2002	1810-2001	Fundamentals - Div Yld + Growth					2.40%	
	Constantinides	2002	1872-2000	Historical Returns & Fundamentals - P/D & P/E					6.90%	
	Cornell	1999	1926-1997	Historical Returns & Fundamental GDP/Earnings		3.50%	5.50%	4.50%	4.50%	
	Easton, Taylor, et al	2002	1981-1998	Residual Income Model					5.30%	
	Fama French	2002	1951-2000	Fundamental DCF with EPS and DPS Growth		2.55%	4.32%		3.44%	
	Harris & Marston	2001	1982-1998	Fundamental DCF with Analysts' EPS Growth					7.14%	
	Best & Byrne	2001								
	McKinsey	2002	1962-2002	Fundamental (P/E, D/P, & Earnings Growth)		3.50%	4.00%		3.75%	
	Siegel	2005	1802-2001	Historical Earnings Yield	Geometric				2.50%	
	Grabowski	2006	1926-2005	Historical and Projected		3.50%	6.00%	4.75%	4.75%	
	Maheu & McCurdy	2006	1885-2003	Historical Excess Returns, Structural Breaks,		4.02%	5.10%	4.56%	4.56%	
	Bostock	2004	1960-2002	Bond Yields, Credit Risk, and Income Volatility		3.90%	1.30%	2.60%	2.60%	
	Bakshi & Chen	2005	1982-1998	Fundamentals - Interest Rates					7.31%	
	Donaldson, Kamstra, & Kramer	2006	1952-2004	Fundamental, Dividend yld., Returns., & Volatility		3.00%	4.00%	3.50%	3.50%	
	Campbell	2008	1982-2007	Historical & Projections (D/P & Earnings Growth)		4.10%	5.40%		4.75%	
	Best & Byrne	2001	Projection	Fundamentals - Div Yld + Growth					2.00%	
	Fernandez	2007	Projection	Required Equity Risk Premium					4.00%	
	DeLong & Magin	2008	Projection	Earnings Yield - TIPS					3.22%	
	Siegel - Rethink ERP	2011	Projection	Real Stock Returns and Components					5.50%	
	American Appraisal Quarterly ERP	2013	Projection	Fundamental Economic and Market Factors					6.50%	
	Duarte & Rosa - NY Fed	2013	projection	Projections from 29 Models					5.40%	
	Duff & Phelps	2013	Projection	Normalized with 4.0% Long-Term Treasury Yield					5.00%	
	Damodaran	2013	Projection	Fundamentals - Implied from FCF to Equity Model					5.74%	
	Social Security									
	Office of Chief Actuary		1900-1995							
	John Campbell	2001	1860-2000	Historical & Projections (D/P & Earnings Growth)	Arithmetic	3.00%	4.00%	3.50%	3.50%	
			Projected for 75 Years		Geometric	1.50%	2.50%	2.00%	2.00%	
	Peter Diamond	2001	Projected for 75 Years	Fundamentals (D/P, GDP Growth)		3.00%	4.80%	3.90%	3.90%	
	John Shoven	2001	Projected for 75 Years	Fundamentals (D/P, P/E, GDP Growth)		3.00%	3.50%	3.25%	3.25%	
	Median									4.00%
Surveys										
	Survey of Financial Forecasters	2013	10-Year Projection	About 50 Financial Forecastsers					2.30%	
	Duke - CFO Magazine Survey	2013	10-Year Projection	Approximately 350 CFOs					4.20%	
	Welch - Academics	2008	30-Year Projection	Random Academics		5.00%	5.74%	5.37%	5.37%	
	Fernandez - Academics, Analysts, and Compan	2013	Long-Term	Survey of Academics, Analysts, and Companies					5.70%	
	Median									4.79%
Building Block										
	Ibbotson and Chen	2013	1926-2012	Historical Supply Model (D/P & Earnings Growth)	Arithmetic			6.13%	5.11%	
					Geometric			4.09%		
	Chen - Rethink ERP	2010	20-Year Projection	Combination Supply Model (Historic and Projection)	Geometric				4.00%	
	Ilmanen - Rethink ERP	2010	Projection	Current Supply Model (D/P & Earnings Growth)	Geometric				3.00%	
	Grinold, Kroner, Siegel - Rethink ERP	2011	Projection	Current Supply Model (D/P & Earnings Growth)	Arithmetic			4.63%	4.12%	
					Geometric			3.60%		
	Woolridge		2013	Current Supply Model (D/P & Earnings Growth)					4.00%	
	Median									4.00%
Mean										4.48%
Median										4.39%

Exhibit JRW-11

Gulf Power Company
Capital Asset Pricing Model
Equity Risk Premium

Summary of 2010-13 Equity Risk Premium Studies

Category	Study Authors	Publication Date	Time Period Of Study	Methodology	Return Measure	Range Low	Range High	Midpoint of Range	Mean	Average
Historical Risk Premium										
	Ibbotson	2013	1926-2012	Historical Stock Returns - Bond Returns	Arithmetic				5.70%	
					Geometric				4.10%	
	Damodaran	2013	1928-2012	Historical Stock Returns - Bond Returns	Arithmetic				5.88%	
					Geometric				4.20%	
	Dimson, Marsh, Staunton	2013	1900-2012	Historical Stock Returns - Bond Returns	Arithmetic					
					Geometric				4.20%	
	Median									4.82%
Ex Ante Models (Puzzle Research)										
	Siegel - Rethink ERP	2011	Projection	Real Stock Returns and Components					5.50%	
	American Appraisal Quarterly ERP	2013	Projection	Fundamental Economic and Market Factors					6.50%	
	Duarte & Rosa - NY Fed	2013	Projection	Projections from 29 Models					5.40%	
	Duff & Phelps	2013	Projection	Normalized with 4.0% Long-Term Treasury Yield					5.00%	
	Damodaran	2013	Projection	Fundamentals - Implied from FCF to Equity Model					5.74%	
	Median									5.50%
Surveys										
	Survey of Financial Forecasters	2013	10-Year Projection	About 50 Financial Forecastsers					2.30%	
	Duke - CFO Magazine Survey	2013	10-Year Projection	Approximately 350 CFOs					4.20%	
	Fernandez - Academics, Analysts, and Companies	2013	Long-Term	Survey of Academics, Analysts, and Companies					5.70%	
	Median									4.20%
Building Block										
	Ibbotson and Chen	2013	Projection	Historical Supply Model (D/P & Earnings Growth)	Arithmetic			6.13%	5.11%	
					Geometric			4.09%		
	Chen - Rethink ERP	2010	20-Year Projection	Combination Supply Model (Historic and Projection)	Geometric				4.00%	
	Ilmanen - Rethink ERP	2010	Projection	Current Supply Model (D/P & Earnings Growth)	Geometric				3.00%	
	Grinold, Kroner, Siegel - Rethink ERP	2011	Projection	Current Supply Model (D/P & Earnings Growth)	Arithmetic			4.63%	4.12%	
					Geometric			3.60%		
	Woolridge	2013	Projection	Current Supply Model (D/P & Earnings Growth)	Geometric				4.00%	
	Median									4.00%
Mean										4.63%
Median										4.51%

Exhibit JRW-12
Gulf Power Company
S&P Bond Ratings

Gulf Power Co.

Issuer Credit Rating

	Ratings	Rating Date
Foreign Long Term	A	21-Dec-2000
Foreign Short Term	A-1	29-Jun-2009
Local Long Term	A	21-Dec-2000
Local Short Term	A-1	29-Jun-2009

Tampa Electric Co.

Issuer Credit Rating

	Ratings	Rating Date
Foreign Long Term	BBB-	27-May-2011
Foreign Short Term	A-2	06-May-2009
Local Long Term	BBB+	27-May-2011
Local Short Term	A-2	06-May-2009

Florida Power & Light Co.

Issuer Credit Rating

	Ratings	Rating Date
Foreign Long Term	A-	11-Mar-2010
Foreign Short Term	A-2	11-Mar-2010
Local Long Term	A-	11-Mar-2010
Local Short Term	A-2	11-Mar-2010

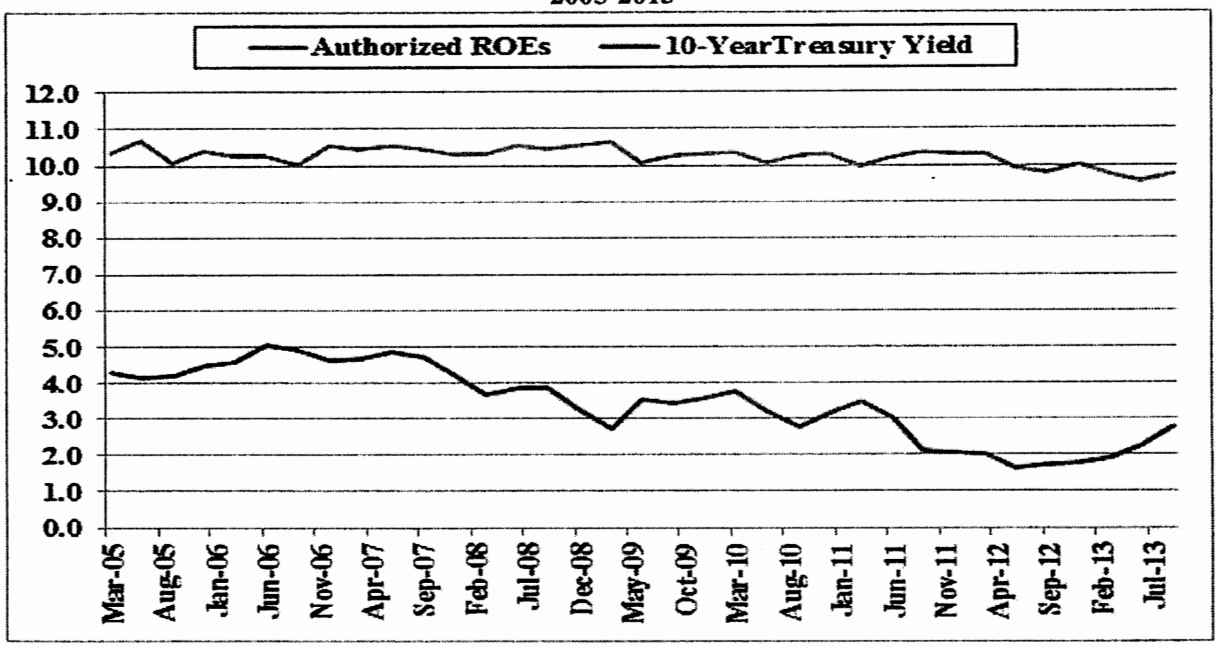
Progress Energy Inc.

Issuer Credit Rating

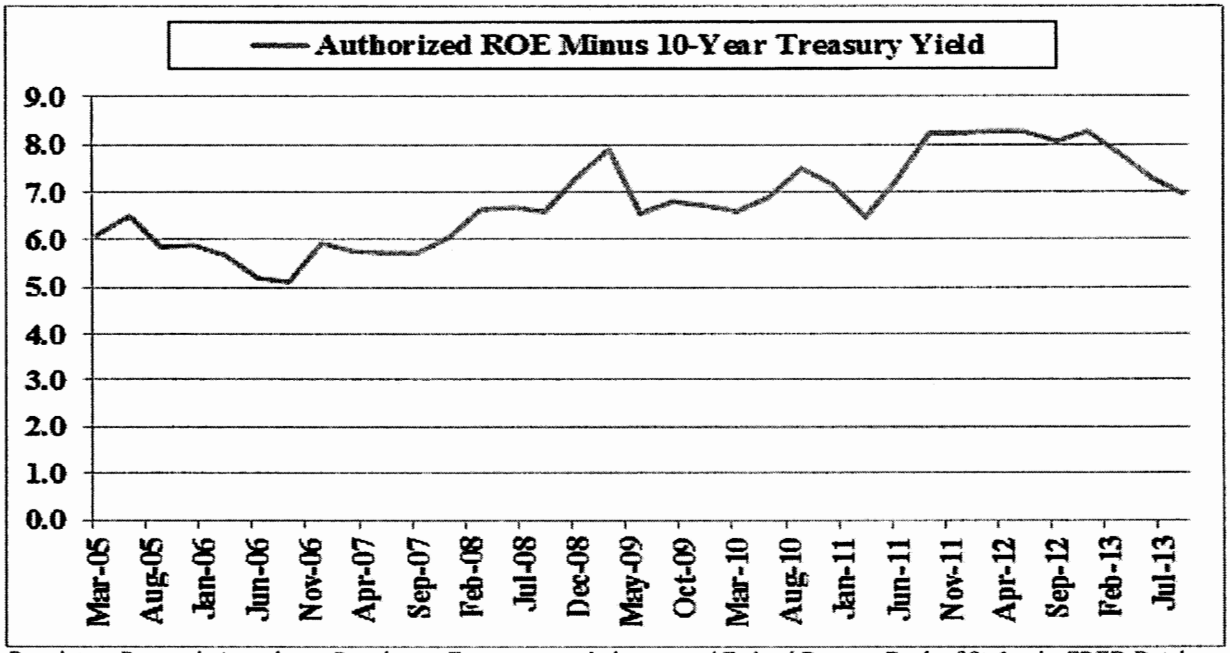
	Ratings	Rating Date
Foreign Long Term	BBB+	15-Mar-2007
Foreign Short Term	A-2	23-Nov-2005
Local Long Term	BBB+	15-Mar-2007
Local Short Term	A-2	23-Nov-2005

Source: www.standardandpoors.com

Exhibit JRW-13
Panel A
Authorized ROEs for Electric Utilities and 10-Year Treasury Yields
2005-2013



Panel B
Authorized ROEs for Electric Utilities Minus 10-Year Treasury Yields
2005-2013



Regulatory Research Associates, *Regulatory Focus*, quarterly issues, and Federal Reserve Bank of St. Louis, FRED Database.

Exhibit JRW-14
Gulf Power Company
Recommended Cost of Capital

Weighted Average Cost of Capital - Regulatory Capital Structure

Capital	Capitalization Amounts	Capitalization Ratios	Cost Rate	Weighted Cost Rate
Short-Term Debt	$ 27,615	1.47%	0.82%	0.01%
Long-Term Debt	$ 685,025	36.36%	4.96%	1.80%
Preferred Stock	$ 79,085	4.20%	6.00%	0.25%
Common Equity	$ 715,221	37.96%	11.50%	4.37%
Customer Deposits	$ 20,943	1.11%	2.30%	0.03%
Deferred Taxes	$ 379,918	20.17%	0.00%	0.00%
FASB 109 Deferred Taxes	$ (25,718)	-1.37%	0.00%	0.00%
Investment Credit - Weighted Cost	$ 1,812	0.10%	8.04%	0.01%
Totals	$ 1,883,901	100.00%		6.47%

MFR D-1a

Panel B - OPC's Recommended Capitalization Ratios for Gulf Power - Investor-Provided Capital

Capital	Capitalization Amounts	Capitalization Ratios	Cost Rate	Weighted Cost Rate
Short-Term Debt	$ 27,615	1.83%	0.82%	0.02%
Long-Term Debt	$ 685,025	45.46%	4.96%	2.25%
Preferred Stock	$ 79,085	5.25%	6.00%	0.31%
Common Equity	$ 715,221	47.46%	11.50%	5.46%
	$ 1,506,946	100.00%		8.04%

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Panel A

Summary of Dr. Vander Weide's Equity Cost Rate Approaches and Results

Approach	Electric Utilities
DCF	10.40%
Ex Ante Risk Premium	11.20%
Ex Post Risk Premium	10.80%
CAPM - Historical	10.40%
CAPM - DCF Based	10.70%
Average	10.70%

Panel B

Summary of Dr. Vander Weide's DCF Results

	Electric Utilities
Average Adjusted Dividend Yield*	4.80%
Growth**	5.60%
DCF Result	10.40%

* Includes adjustments for quarterly payments and flotation costs
** Expected EPS Growth from IBES

Panel C

Summary of Dr. Vander Weide's Ex Ante Risk Premium Results

	Electric Utilities
Projected 'A' Rated PU Yield	6.55%
Ex Ante Risk Premium	4.62%
Equity Cost Rate	11.20%

Panel D

Summary of Dr. Vander Weide's Historical Risk Premium Results

	Electric Utilities
Projected 'A' Rated PU Yield	6.55%
Historic Risk Premium*	4.05%
Equity Cost Rate	10.60%
Flotation Cost Adjustment	0.20%
Adjusted CAPM Result	10.80%

* Midpoint of 3.8% and 4.3%

Panel E

Summary of Dr. Vander Weide's Historical CAPM Results

	Electric Utilities
Risk-Free Rate	5.25%
Beta	0.73
Equity Risk Premium	6.70%
CAPM Result	10.16%
Flotation Cost Adjustment	0.24%
Adjusted CAPM Result	10.40%

Panel F

Summary of Dr. Vander Weide's Expected CAPM Results

	Utility Proxy Group
Risk-Free Rate	5.25%
Beta	0.73
Equity Risk Premium	7.15%
CAPM Result	10.47%
Flotation Cost Adjustment	0.24%
Adjusted CAPM Result	10.70%

Exhibit JRW-15
Growth Rates
GDP, S&P 500 Price, EPS, and DPS

	GDP	S&P 500	Earnings	Dividends	
1960	526.4	58.11	3.10	1.98	
1961	544.8	71.55	3.37	2.04	
1962	585.7	63.10	3.67	2.15	
1963	617.8	75.02	4.13	2.35	
1964	663.6	84.75	4.76	2.58	
1965	719.1	92.43	5.30	2.83	
1966	787.7	80.33	5.41	2.88	
1967	832.4	96.47	5.46	2.98	
1968	909.8	103.86	5.72	3.04	
1969	984.4	92.06	6.10	3.24	
1970	1038.3	92.15	5.51	3.19	
1971	1126.8	102.09	5.57	3.16	
1972	1237.9	118.05	6.17	3.19	
1973	1382.3	97.55	7.96	3.61	
1974	1499.5	68.56	9.35	3.72	
1975	1637.7	90.19	7.71	3.73	
1976	1824.6	107.46	9.75	4.22	
1977	2030.1	95.10	10.87	4.86	
1978	2293.8	96.11	11.64	5.18	
1979	2562.2	107.94	14.55	5.97	
1980	2788.1	135.76	14.99	6.44	
1981	3126.8	122.55	15.18	6.83	
1982	3253.2	140.64	13.82	6.93	
1983	3534.6	164.93	13.29	7.12	
1984	3930.9	167.24	16.84	7.83	
1985	4217.5	211.28	15.68	8.20	
1986	4460.1	242.17	14.43	8.19	
1987	4736.4	247.08	16.04	9.17	
1988	5100.4	277.72	24.12	10.22	
1989	5482.1	353.40	24.32	11.73	
1990	5800.5	330.22	22.65	12.35	
1991	5992.1	417.09	19.30	12.97	
1992	6342.3	435.71	20.87	12.64	
1993	6667.4	466.45	26.90	12.69	
1994	7085.2	459.27	31.75	13.36	
1995	7414.7	615.93	37.70	14.17	
1996	7838.5	740.74	40.63	14.89	
1997	8332.4	970.43	44.09	15.52	
1998	8793.5	1229.23	44.27	16.20	
1999	9353.5	1469.25	51.68	16.71	
2000	9951.5	1320.28	56.13	16.27	
2001	10286.2	1148.09	38.85	15.74	
2002	10642.3	879.82	46.04	16.08	
2003	11142.2	1111.91	54.69	17.88	
2004	11853.3	1211.92	67.68	19.41	
2005	12623.0	1248.29	76.45	22.38	
2006	13377.2	1418.30	87.72	25.05	
2007	14028.7	1468.36	82.54	27.73	
2008	14291.5	903.25	65.39	28.05	
2009	13973.7	1115.10	59.65	22.31	
2010	14498.9	1257.64	83.66	23.12	
2011	15075.7	1257.60	97.05	26.02	Average
2012	15681.5	1426.19	102.47	30.44	
Growth Rates	**6.74**	**6.35**	**6.96**	**5.39**	**6.36**

Data Sources: GDPA - http://research.stlouisfed.org/fred2/categories/106
S&P 500, EPS and DPS - http://pages.stern.nyu.edu/~adamodar/

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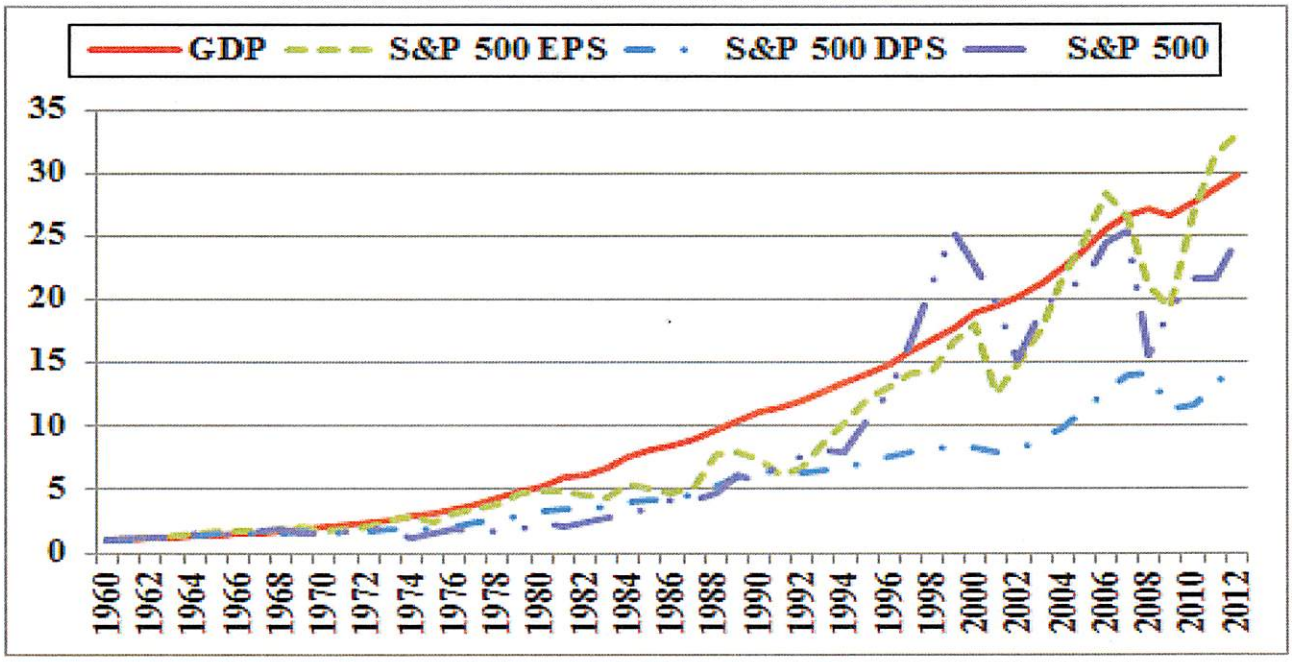
Exhibit JRW-15
Long-Term Growth of GDP, S&P 500, S&P 500 EPS, and S&P 500 DPS



	GDP	S&P 500	S&P 500 EPS	S&P 500 DPS
Growth Rates	6.74%	6.35%	6.96%	5.39%

Exhibit JRW-15
Panel A
Historic GDP Growth Rates

10-Year Average	4.0%
20-Year Average	4.6%
30-Year Average	5.1%
40-Year Average	6.6%
50-Year Average	6.8%

Calculated from Page 1 of Exhibit JRW-15

Panel B
Projected GDP Growth Rates

	Time Frame	Projected Nominal GDP Growth Rate
Congressional Budget Office	2013-2023	4.6%
Survey of Financial Forecasters	Ten Year	4.8%
Energy Information Administration	2011-2040	4.5%

Sources:
http://www.cbo.gov/ftpdocs/120xx/doc12039/01-26_FY2013Outlook.pdf page XIII
http://www.eia.gov/forecasts/aeo/tables_ref.cfm Table 20
http://www.philadelphiafed.org/research-and-data/real-time-center/survey-of-professional-forecasters/2013/survq113.cfm

J. Randall Woolridge

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120 Haymaker Circle
State College, PA 16801
814-238-9428

Academic Experience

Professor of Finance, the Smeal College of Business Administration, the Pennsylvania State University (July 1, 1990 to the present).

President, Nittany Lion Fund LLC, (January 1, 2005 to the present)
Director, the Smeal College Trading Room (January 1, 2001 to the present)
Goldman, Sachs & Co. and Frank P. Smeal Endowed University Fellow in Business Administration (July 1, 1987 to the present).

Associate Professor of Finance, College of Business Administration, the Pennsylvania State University (July 1, 1984 to June 30, 1990).
Assistant Professor of Finance, College of Business Administration, the Pennsylvania State University (September, 1979 to June 30, 1984).

Education

Doctor of Philosophy in Business Administration, the University of Iowa (December, 1979). Major field: Finance.
Master of Business Administration, the Pennsylvania State University (December, 1975).
Bachelor of Arts, the University of North Carolina (May, 1973) Major field: Economics.

Books

James A. Miles and J. Randall Woolridge, *Spinoffs and Equity Carve-Outs: Achieving Faster Growth and Better Performance* (Financial Executives Research Foundation), 1999
Patrick Cusatis, Gary Gray, and J. Randall Woolridge, *The StreetSmart Guide to Valuing a Stock* (2nd Edition, McGraw-Hill), 2003.
J. Randall Woolridge and Gary Gray, *The New Corporate Finance, Capital Markets, and Valuation: An Introductory Text* (Kendall Hunt, 2003).

Research

Dr. Woolridge has published over 35 articles in the best academic and professional journals in the field, including the *Journal of Finance,* the *Journal of Financial Economics,* and the *Harvard Business Review*.

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Exhibit JRW-16

Appendix A
Educational Background, Research, and Related Business Experience
J. Randall Woolridge

J. Randall Woolridge is a Professor of Finance and the Goldman, Sachs & Co. and Frank P. Smeal Endowed Faculty Fellow in Business Administration in the College of Business Administration of the Pennsylvania State University in University Park, PA. In addition, Professor Woolridge is Director of the Smeal College Trading Room and President and CEO of the Nittany Lion Fund, LLC.

Professor Woolridge received a Bachelor of Arts degree in Economics from the University of North Carolina, a Master of Business Administration degree from the Pennsylvania State University, and a Doctor of Philosophy degree in Business Administration (major area-finance, minor area-statistics) from the University of Iowa. He has taught Finance courses including corporation finance, commercial and investment banking, and investments at the undergraduate, graduate, and executive MBA levels.

Professor Woolridge's research has centered on empirical issues in corporation finance and financial markets. He has published over 35 articles in the best academic and professional journals in the field, including the *Journal of Finance,* the *Journal of Financial Economics,* and the *Harvard Business Review.* His research has been cited extensively in the business press. His work has been featured in the *New York Times*, *Forbes, Fortune, The Economist*, *Barron's*, *Wall Street Journal*, *Business Week*, *Investors' Business Daily*, *USA Today*, and other publications. In addition, Dr. Woolridge has appeared as a guest to discuss the implications of his research on CNN's *Money Line*, CNBC's *Morning Call* and *Business Today*, and Bloomberg's *Morning Call.*

Professor Woolridge's stock valuation book, *The StreetSmart Guide to Valuing a Stock* (McGraw-Hill, 2003), was released in its second edition. He has also co-authored *Spinoffs and Equity Carve-Outs: Achieving Faster Growth and Better Performance* (Financial Executives Research Foundation, 1999) as well as a textbook entitled *Basic Principles of Finance* (Kendall Hunt, 2011).

Professor Woolridge has also consulted with corporations, financial institutions, and government agencies. In addition, he has directed and participated in university- and company-sponsored professional development programs for executives in 25 countries in North and South America, Europe, Asia, and Africa.

Over the past twenty-five years Dr. Woolridge has prepared testimony and/or provided consultation services in regulatory rate cases in the rate of return area in following states: Alaska, Arizona, California, Colorado, Connecticut, Delaware, Florida, Hawaii, Indiana, Kansas, Kentucky, Massachusetts, Missouri, Nebraska, New Jersey, New York, Ohio, Oklahoma, Pennsylvania, South Carolina, Texas, Utah, Vermont, Washington, and Washington, D.C. He has also prepared testimony which was submitted to the Federal Energy Regulatory Commission.

Most of the attention given to the accuracy of analysts' earnings per share ("EPS") forecasts comes from media coverage of companies' quarterly earnings announcements. When companies' announced earnings beat Wall Street's EPS estimates ("a positive surprise"), their stock prices usually go up. When a company's EPS figure misses or is below Wall Street's forecasted EPS ("a negative surprise"), their stock price usually declines, sometimes precipitously so. Wall Street's estimate is the consensus forecast for quarterly EPS made by analysts who follow the stock as of the announcement date. And so Wall Street's estimate is the consensus EPS made in the days leading up to the EPS announcement.

In recent years, it has become more common for companies to beat Wall Street's quarterly EPS estimate. A recent *Wall Street Journal* article summarized the results for the first quarter of 2012: "While this "positive surprise ratio" of 70% is above the 20-year average of 58% and also higher than last quarter's tally, it is just middling since the current bull market began in 2009. In the past decade, the ratio only dipped below 60% during the financial crisis. Look before 2002, though, and 70% would have been literally off the chart. From 1993 through 2001, about half of companies had positive surprises."[1] Figure 1 below provides the record for companies beating Wall Street's EPS estimate on a quarterly basis over the past 20 years.

[1] Spencer Jakab, "Earnings Surprises Lose Punch," *Wall Street Journal* (May 7, 2012), p. C1.

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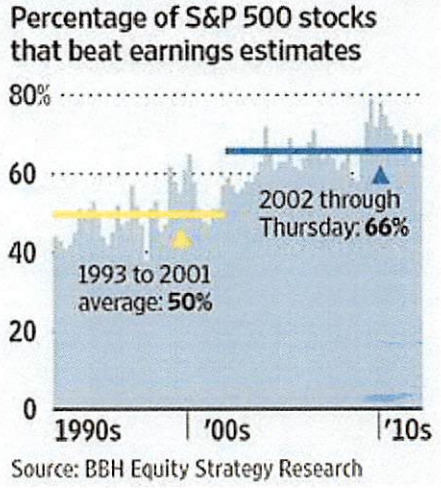
Figure 1
Percent of Companies Beating Wall Street's Quarterly Estimates



A. RESEARCH ON THE ACCURACY OF ANALYSTS' NEAR-TERM EPS ESTIMATES

There is a long history of studies that evaluate how well analysts forecast near-term EPS estimates and long-term EPS growth rates. Most of these studies have evaluated the accuracy of earnings forecasts for the current quarter or year. Many of the early studies indicated that analysts make overly optimistic EPS earnings forecasts for quarter-to-quarter EPS (Stickel (1990); Brown (1997); Chopra (1998)).[2] More recent studies have shown that the optimistic bias tends to be larger for longer-term forecasts and smaller for forecasts made nearer to the

[2] S. Stickel, "Predicting Individual Analyst Earnings Forecasts," *Journal of Accounting Research*, Vol. 28, 409-417, 1990. Brown, L.D., "Analyst Forecasting Errors: Additional Evidence," *Financial Analysts Journal*, Vol. 53, 81-88, 1997, and Chopra, V.K., "Why So Much Error in Analysts' Earnings Forecasts?" *Financial Analysts Journal*, Vol. 54, 30-37 (1998).

EPS announcement date. Richardson, Teoh, and Wysocki (2004) report that the upward bias in earnings growth rates declines in the quarters leading up to the earnings announcement date.[3] They call this result the "walk-down to beatable analyst forecasts." They hypothesize that the walk-down might be driven by the "earning-guidance game," in which analysts give optimistic forecasts at the start of a fiscal year, then revise their estimates downwards until the firm can beat the forecasts at the earnings announcement date.

However, two regulatory developments over the past decade have potentially impacted analysts' EPS growth rate estimates. First, Regulation Fair Disclosure ("Reg FD") was introduced by the Securities and Exchange Commission ("SEC") in October 2000. Reg FD prohibits private communication between analysts and management to level the information playing field in the markets. With Reg FD, analysts are less dependent on gaining access to management to obtain information and, therefore, are not as likely to make optimistic forecasts to gain access to management. Second, the conflict of interest within investment firms with investment banking and analyst operations was addressed in the Global Analysts Research Settlements ("GARS"). GARS, as agreed upon on April 23, 2003, between the SEC, the National Association of Securities Dealers ("NASD"), the New York Stock Exchange ("NYSE") and ten of the largest U.S. investment firms, includes a number of regulations that were

[3] S. Richardson, S. Teoh, and P. Wysocki, "The Walk-Down to Beatable Analyst Forecasts: The Role of Equity Issuance and Insider Trading Incentives," *Contemporary Accounting Research*, pp. 885–924, (2004).

introduced to prevent investment bankers from pressuring analysts to provide favorable projections.

The previously cited *Wall Street Journal* article acknowledged the impact of the new regulatory rules in explaining the recent results:[4] "What changed? One potential reason is the tightening of rules governing analyst contacts with management. Analysts now must rely on publicly available guidance or, gasp, figure things out by themselves. That puts companies, with an incentive to set the bar low so that earnings are received positively, in the driver's seat. While that makes managers look good short-term, there is no lasting benefit for buy-and-hold investors."

These comments on the impact of regulatory developments on the accuracy of short-term EPS estimates was addressed in a study by Hovakimian and Saenyasiri (2010).[5] The authors investigate analysts' forecasts of annual earnings for the following time periods: (1) the time prior to Reg FD (1984-2000); (2) the time period after Reg FD but prior to GARS (2000-2002);[6] and (3) the time period after GARS (2002-2006). For the pre-Reg FD period, Hovakimian and Saenyasiri find that analysts generally make overly optimistic forecasts of annual earnings. The forecast bias is higher for early forecasts and

[4] Spencer Jakab, "Earnings Surprises Lose Punch," *Wall Street Journal* (May 7, 2012), p. C1.

[5] A. Hovakimian and E. Saenyasiri, "Conflicts of Interest and Analysts Behavior: Evidence from Recent Changes in Regulation," *Financial Analysts* Journal (July-August, 2010), pp. 96-107.

[6] Whereas the GARS settlement was signed in 2003, rules addressing analysts' conflict of interest by separating the research and investment banking activities of analysts went into effect with the passage of NYSE and NASD rules in July 2002.

steadily declines in the months leading up to the earnings announcement. The results are similar for the time period after Reg FD but prior to GARS. However, the bias is lower in the later forecasts (the forecasts made just prior to the announcement). For the time period after GARS, the average forecasts declined significantly, but a positive bias remains. In sum, Hovakimian and Saenyasiri find that: (1) analysts make overly optimistic short-term forecasts of annual earnings; (2) Reg FD had no effect on this bias; and (3) GARS did result in a significant reduction in the bias, but analysts' short-term forecasts of annual earnings still have a small positive bias.

B. RESEARCH ON THE ACCURACY OF ANALYSTS' LONG-TERM EPS GROWTH RATE FORECASTS

There have been very few studies regarding the accuracy of analysts' long-term EPS growth rate forecasts. Cragg and Malkiel (1968) studied analysts' long-term EPS growth rate forecasts made in 1962 and 1963 by five brokerage houses for 185 firms. They concluded that analysts' long-term earnings growth forecasts are on the whole no more accurate than naïve forecasts based on past earnings growth. Harris (1999) evaluated the accuracy of analysts' long-term EPS forecasts over the 1982-1997 time period using a sample of 7,002 firm-year observations.[7] He concluded the following: (1) the accuracy of analysts' long-term EPS forecasts is very low; (2) a superior long-run method to forecast long-term EPS growth is to assume that all companies will have an earnings growth

[7] R.D. Harris, "The Accuracy, Bias, and Efficiency of Analysts' Long Run Earnings Growth Forecasts," *Journal of Business Finance & Accounting*, pp. 725-755 (June/July 1999).

rate equal to historic GDP growth; and (3) analysts' long-term EPS forecasts are significantly upwardly biased, with forecasted earnings growth exceeding actual earnings growth by seven percent per annum. Subsequent studies by DeChow, P., A. Hutton, and R. Sloan (2000), and Chan, Karceski, and Lakonishok (2003) also conclude that analysts' long-term EPS growth rate forecasts are overly optimistic and upwardly biased.[8] The Chan, Karceski, and Lakonishok (2003) study evaluated the accuracy of analysts' long-term EPS growth rate forecasts over the 1982-98 time period. They reported a median Institutional Brokers' Estimate System ("I/B/E/S") growth forecast of 14.5%, versus a median realized 5-year growth rate of about 9%. They also found that the I/B/E/S forecasts of EPS beyond 2 years are not accurate. They concluded the following: "Over long horizons, however, there is little forecastability in earnings, and analysts' estimates tend to be overly optimistic."

Lacina, Lee, and Xu (2011) evaluated the accuracy of analysts' long-term earnings growth rate forecasts over the 1983-2003 time period.[9] The study included 27,081 firm-year observations, and compared the accuracy of analysts' EPS forecasts to those produced by two naïve forecasting models: (1) a random

[8] P. DeChow, A. Hutton, and R. Sloan, "The Relation Between Analysts' Forecasts of Long-Term Earnings Growth and Stock Price Performance Following Equity Offerings," *Contemporary Accounting Research (2000)* and K. Chan, L., Karceski, J., & Lakonishok, J., "The Level and Persistence of Growth Rates," *Journal of Finance* pp. 643–684, (2003).

[9] M. Lacina, B. Lee and Z. Xu, *Advances in Business and Management Forecasting (Vol. 8),* Kenneth D. Lawrence, Ronald K. Klimberg (ed.), Emerald Group Publishing Limited, pp.77-101.

walk model ("RW") where the long-term EPS (t+5) is simply equal to last year's EPS figure (t-1); and (2) a RW model with drift ("RWGDP"), where the drift or growth rate is GDP growth for period t-1. In this model, long-term EPS (t+5) is simply equal to last year's EPS figure (t-1) times (1 + GDP growth (t-1)). The authors conclude that using the RW model to forecast EPS in the next 3-5 years proved to be just as accurate as using the EPS estimates from analysts' long-term earnings growth rate forecasts. They find that the RWGDP model performs better than the pure RW model, and that both models perform as well as analysts in forecasting long-term EPS. They also discover an optimistic bias in analysts' long-term EPS forecasts. In the authors' opinion, these results indicate that analysts' long-term earnings growth rate forecasts should be used with caution as inputs for valuation and cost of capital purposes.

C. ISSUES REGARDING THE SUPERIORITY OF ANALYSTS' EPS FORECASTS OVER HISTORIC AND TIME-SERIES ESTIMATES OF LONG-TERM EPS GROWTH

As highlighted by the classic study by Brown and Rozeff (1976) and the other studies that followed, analysts' forecasts of quarterly earnings estimates are superior to the estimates derived from historic and time-series analyses.[10] This is often attributed to the information and timing advantage that analysts have over historic and time-series analyses. These studies relate to analysts' forecasts of quarterly and/or annual forecasts, and not to long-term EPS growth rate forecasts.

[10] L. Brown and M. Rozeff, "The Superiority of Analyst Forecasts as Measures of Expectations: Evidence from Earnings," *The Journal of Finance* 33 (1): pp. 1-16 (1976).

The previously cited studies by Harris (1999); Chan, Karceski, and Lakonishok (2003); and Lacina, Lee, and Xu (2011) all conclude that analysts' forecasts are no better than time-series models and historic growth rates in forecasting long-term EPS. Harris (1999) and Lacina, Lee, and Xu (2011) concluded that historic GDP growth was superior to analysts' forecasts for long-run earnings growth. These overall results are similar to the findings by Bradshaw, Drake, Myers, and Myers (2009) that discovered that time-series estimates of annual earnings are more accurate over longer horizons than analysts' forecasts of earnings. As the authors state, "These findings suggest an incomplete and misleading generalization about the superiority of analysts' forecasts over even simple time-series-based earnings forecasts."[11]

D. STUDY OF THE ACCURACY OF ANALYSTS' LONG-TERM EARNINGS GROWTH RATES

To evaluate the accuracy of analysts' EPS forecasts, I have compared actual 3-5 year EPS growth rates with forecasted EPS growth rates on a quarterly basis over the past 20 years for all companies covered by the I/B/E/S data base. In Panel A of page 1 of Exhibit JRW-16, Appendix B1, I show the average analysts' forecasted 3-5 year EPS growth rate with the average actual 3-5 year EPS growth rate for the past 20 years.

The following example shows how the results can be interpreted. For the 3-5 year period prior to the first quarter of 1999, analysts had projected an EPS

[11] M. Bradshaw, M. Drake, J. Myers, and L. Myers, "A Re-examination of Analysts' Superiority Over Time-Series Forecasts," Workings paper, (1999), http://ssrn.com/abstract=1528987.

growth rate of 15.13%, but companies only generated an average annual EPS growth rate of 9.37% over the 3-5 years. This projected EPS growth rate figure represented the average projected growth rate for over 1,510 companies, with an average of 4.88 analysts' forecasts per company. For the entire 20-year period of the study, for each quarter there were on average 5.6 analysts' EPS projections for 1,281 companies. Overall, my findings indicate that forecast errors for long-term estimates are predominantly positive, which indicates an upward bias in growth rate estimates. The mean and median forecast errors over the observation period are 143.06% and 75.08%, respectively. The forecasting errors are negative for only 11 of the 80 quarterly time periods: five consecutive quarters starting at the end of 1995 and six consecutive quarters starting in 2006. As shown in Panel A of page 1 of Exhibit JRW-16, Appendix B1, the quarters with negative forecast errors were for the 3-5 year periods following earnings declines associated with the 1991 and 2001 economic recessions in the U.S. Thus, there is evidence of a persistent upward bias in long-term EPS growth forecasts.

The average 3-5 year EPS growth rate projections for all companies provided in the I/B/E/S database on a quarterly basis from 1988 to 2008 are shown in Panel B of page 1 of Exhibit JRW-16, Appendix B1. In this graph, no comparison to actual EPS growth rates is made, and hence, there is no follow-up period. Therefore, since companies are not lost from the sample due to a lack of follow-up EPS data, these results are for a larger sample of firms. The average

projected growth rate increased to the 18.0% range in 2006, and has since decreased to about 14.0%.

The upward bias in analysts' long-term EPS growth rate forecasts appears to be known in the markets. Page 2 of Exhibit JRW-16, Appendix B1 provides an article published in the *Wall Street Journal*, dated March 21, 2008, that discusses the upward bias in analysts' EPS growth rate forecasts.[12] In addition, a recent *Bloomberg Businessweek* article also highlighted the upward bias in analysts' EPS forecasts, citing a study by McKinsey Associates. This article is provided on pages 3 and 4 of Exhibit JRW-16, Appendix B1. The article concludes with the following:[13]

The bottom line: *Despite reforms intended to improve Wall Street research, stock analysts seem to be promoting an overly rosy view of profit prospects.*

E. REGULATORY DEVELOPMENTS AND THE ACCURACY OF ANALYSTS' LONG-TERM EARNINGS GROWTH RATES FORECASTS

Whereas Hovakimian and Saenyasiri evaluated the impact of regulations on analysts' short-term EPS estimates, there is little research on the impact of Reg FD and GARS on the long-term EPS forecasts of Wall Street analysts. My study with Patrick Cusatis did find that the long-term EPS growth rate forecasts of analysts did not decline significantly and have continued to be overly optimistic in

[12] Andrew Edwards, "Study Suggests Bias in Analysts' Rosy Forecasts," *Wall Street Journal* (March 21, 2008), p. C6.
[13] Roben Farzad, 'For Analysts, Things are Always Looking Up,' *Bloomberg Businessweek* (June 14, 2010), pp. 39-40.

the post-Reg FD and GARS period.[14] Analysts' long-term EPS growth rate forecasts before and after GARS are about two times the level of historic GDP growth. These observations are supported by a *Wall Street Journal* article entitled "Analysts Still Coming Up Rosy – Over-Optimism on Growth Rates is Rampant – and the Estimates Help to Buoy the Market's Valuation." The following quote provides insight into the continuing bias in analysts' forecasts:

> Hope springs eternal, says Mark Donovan, who manages Boston Partners Large Cap Value Fund. "You would have thought that, given what happened in the last three years, people would have given up the ghost. But in large measure they have not.
>
> These overly optimistic growth estimates also show that, even with all the regulatory focus on too-bullish analysts allegedly influenced by their firms' investment-banking relationships, a lot of things haven't changed. Research remains rosy and many believe it always will.[15]

These observations are echoed in a recent McKinsey study entitled "Equity Analysts: Still too Bullish" which involved a study of the accuracy on analysts long-term EPS growth rate forecasts. The authors conclude that after a decade of stricter regulation, analysts' long-term earnings forecasts continue to be excessively optimistic. They made the following observation (emphasis added):[16]

---

[14] P. Cusatis and J. R. Woolridge, "The Accuracy of Analysts' Long-Term EPS Growth Rate Forecasts," Working Paper (July 2008).

[15] Ken Brown, "Analysts Still Coming Up Rosy – Over-Optimism on Growth Rates is Rampant – and the Estimates Help to Buoy the Market's Valuation," *Wall Street Journal*, p. C1, (January 27, 2003).

[16] Marc H. Goedhart, Rishi Raj, and Abhishek Saxena, "Equity Analysts, Still Too Bullish," *McKinsey on Finance*, pp. 14-17, (Spring 2010).

> Alas, a recently completed update of our work only reinforces this view—despite a series of rules and regulations, dating to the last decade, that were intended to improve the quality of the analysts' long-term earnings forecasts, restore investor confidence in them, and prevent conflicts of interest. For executives, many of whom go to great lengths to satisfy Wall Street's expectations in their financial reporting and long-term strategic moves, this is a cautionary tale worth remembering. This pattern confirms our earlier findings that analysts typically lag behind events in revising their forecasts to reflect new economic conditions. When economic growth accelerates, the size of the forecast error declines; when economic growth slows, it increases. So as economic growth cycles up and down, the actual earnings S&P 500 companies report occasionally coincide with the analysts' forecasts, as they did, for example, in 1988, from 1994 to 1997, and from 2003 to 2006. Moreover, analysts have been persistently overoptimistic for the past 25 years, with estimates ranging from 10 to 12 percent a year, compared with actual earnings growth of 6 percent. Over this time frame, actual earnings growth surpassed forecasts in only two instances, both during the earnings recovery following a recession. On average, analysts' forecasts have been almost 100 percent too high.

F. ANALYSTS' LONG-TERM EPS GROWTH RATE FORECASTS FOR UTILITY COMPANIES

To evaluate whether analysts' EPS growth rate forecasts are upwardly biased for utility companies, I conducted a study similar to the one described above using a group of electric utility and gas distribution companies. The results are shown on Panels A and B of page 5 of Exhibit JRW-16, Appendix B1. The projected EPS growth rates for electric utilities have been in the 4% to 6% range over the last 20 years, with the recent figures at approximately 5%. As shown, the achieved EPS growth rates have been volatile and, on average, below the projected growth rates. Over the entire period, the average quarterly 3-5 year projected and actual EPS growth rates are 4.59% and 2.90%, respectively.

For gas distribution companies, the projected EPS growth rates have declined from about 6% in the 1990s to about 5% in the 2000s. The achieved EPS growth rates have been volatile. Over the entire period, the average quarterly 3-5 year projected and actual EPS growth rates are 5.15% and 4.53%, respectively.

Overall, the upward bias in EPS growth rate projections for electric utility and gas distribution companies is not as pronounced as it is for all companies. Nonetheless, the results here are consistent with the results for companies in general -- analysts' projected EPS growth rate forecasts are upwardly biased for utility companies.

G. *VALUE LINE*'S LONG-TERM EPS GROWTH RATE FORECASTS

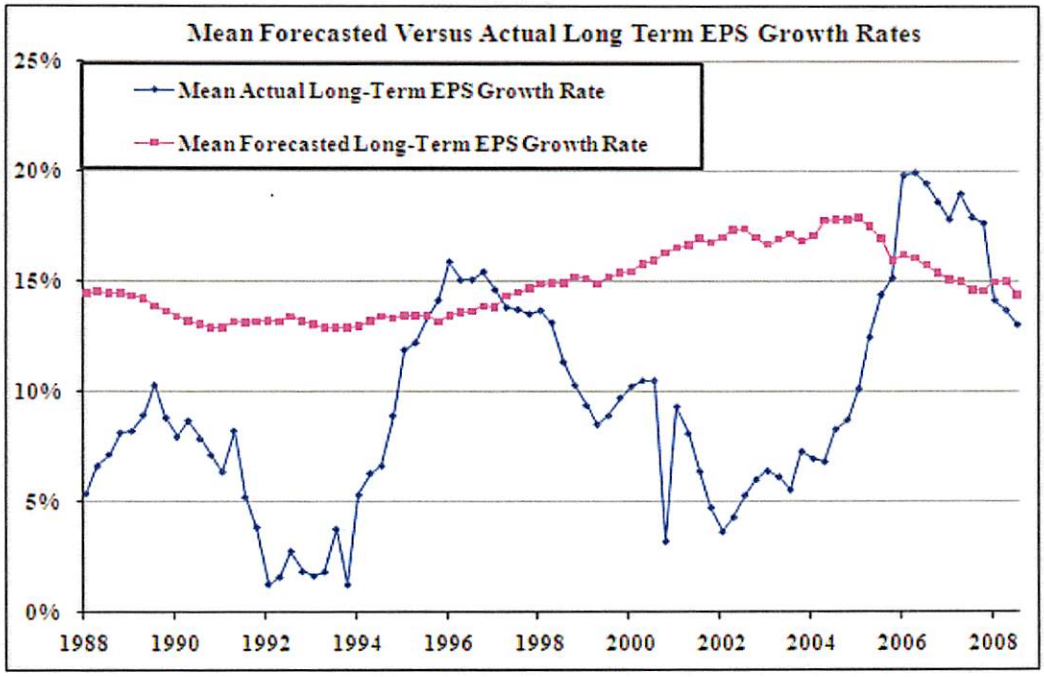
To assess *Value Line*'s earnings growth rate forecasts, I used the *Value Line Investment Analyzer*. The results are summarized in Panel A of Page 6 of Exhibit JRW-16, Appendix B1. I initially filtered the database and found that *Value Line* has 3-5 year EPS growth rate forecasts for 2,333 firms. The average projected EPS growth rate was 14.70%. This is high given that the average historical EPS growth rate in the U.S. is about 7%. A major factor seems to be that *Value Line* only predicts negative EPS growth for 43 companies. This is less than 2% of the companies covered by *Value Line*. Given the ups and downs of corporate earnings, this is unreasonable.

To put this figure in perspective, I screened the *Value Line* companies to see what percent of companies covered by *Value Line* had experienced negative

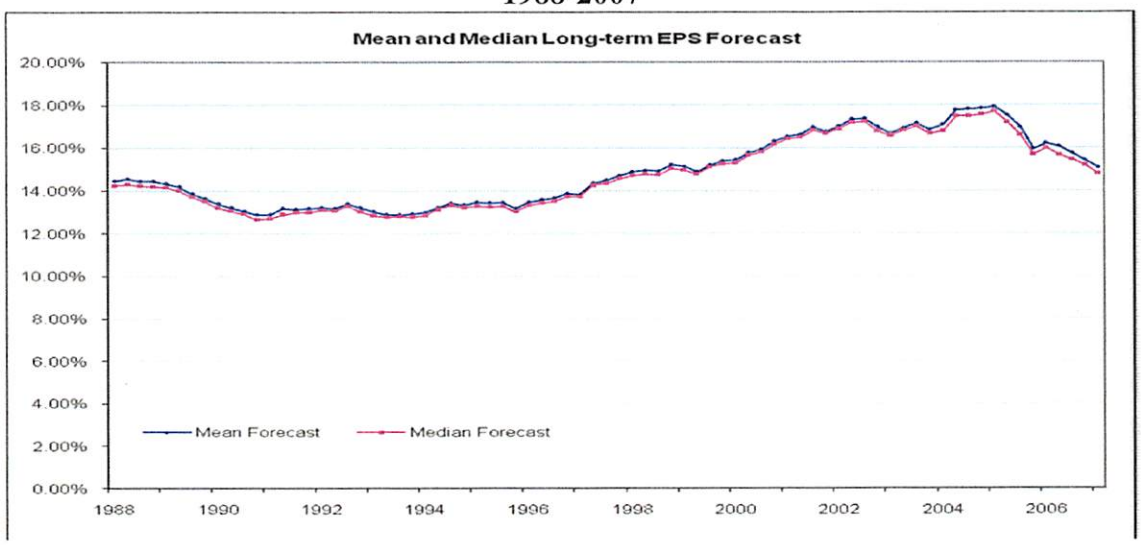
EPS growth rates over the past 5 years. *Value Line* reported a 5-year historic growth rate for 2,219 companies. The results are shown in Panel B of page 6 of Exhibit JRW-16, Appendix B1 and indicate that the average 5-year historic growth rate was 3.90%, and *Value Line* reported negative historic growth for 844 firms, which represents 38.0% of these companies.

These results indicate that *Value Line*'s EPS forecasts are excessive and unrealistic. It appears that the analysts at *Value Line* are similar to their Wall Street brethren in that they are reluctant to forecast negative earnings growth.

Panel A
Long-Term Forecasted Versus Actual EPS Growth Rates
1988-2009



Panel B
Long-Term Forecasted EPS Growth Rates
1988-2007



Source: Patrick J. Cusatis and J. Randall Woolridge, "The Accuracy of Analysts' Long-Term Earnings Per Share Growth Rate Forecasts," (July, 2008).

THE WALL STREET JOURNAL.

Study Suggests Bias in Analysts' Rosy Forecasts

By ANDREW EDWARDS
March 21, 2008; Page C6

Despite an economy teetering on the brink of a recession -- if not already in one -- analysts are still painting a rosy picture of earnings growth, according to a study done by Penn State's Smeal College of Business.

The report questions analysts' impartiality five years after then-New York Attorney General Eliot Spitzer forced analysts to pay $1.5 billion in damages after finding evidence of bias.

"Wall Street analysts basically do two things: recommend stocks to buy and forecast earnings," said J. Randall Woolridge, professor of finance. "Previous studies suggest their stock recommendations do not perform well, and now we show that their long-term earnings-per-share growth-rate forecasts are excessive and upwardly biased."

The report, which examined analysts' long-term (three to five years) and one-year per-share earnings expectations from 1984 through 2006 found that companies' long-term earnings growth surpassed analysts' expectations in only two instances, and those came right after recessions.

Over the entire time period, analysts' long-term forecast earnings-per-share growth averaged 14.7%, compared with actual growth of 9.1%. One-year per-share earnings expectations were slightly more accurate: The average forecast was for 13.8% growth and the average actual growth rate was 9.8%.

"A significant factor in the upward bias in long-term earnings-rate forecasts is the reluctance of analysts to forecast" profit declines, Mr. Woolridge said. The study found that nearly one-third of all companies experienced profit drops over successive three-to-five-year periods, but analysts projected drops less than 1% of the time.

The study's authors said, "Analysts are rewarded for biased forecasts by their employers, who want them to hype stocks so that the brokerage house can garner trading commissions and win underwriting deals."

They also concluded that analysts are under pressure to hype stocks to generate trading commissions, and they often don't follow stocks they don't like.

Write to Andrew Edwards at andrew.edwards@dowjones.com

Markets & Finance June 10, 2010, 5:00PM EST

Bloomberg Businessweek

For Analysts, Things Are Always Looking Up

They're raising earnings estimates for U.S. companies at a record pace

By Roben Farzad

For years, the rap on Wall Street securities analysts was that they were shills, reflexively producing upbeat research on companies they cover to help their employers win investment banking business. The dynamic was well understood: Let my bank take your company public, or advise it on this acquisition, and—wink, wink—I will recommend your stock through thick or thin. After the Internet bubble burst, that was supposed to change. In April 2003 the Securities & Exchange Commission reached a settlement with 10 Wall Street firms in which they agreed, among other things, to separate research from investment banking.

Seven years on, Wall Street analysts remain a decidedly optimistic lot. Some economists look at the global economy and see troubles—the European debt crisis, persistently high unemployment worldwide, and housing woes in the U.S. Stock analysts as a group seem unfazed. Projected 2010 profit growth for companies in the Standard & Poor's 500-stock index has climbed seven percentage points this quarter, to 34 percent, data compiled by Bloomberg show. According to Sanford C. Bernstein (AB), that's the fastest pace since 1980, when the Dow Jones industrial average was quoted in the hundreds and Nancy Reagan was getting ready to order new window treatments for the Oval Office.

Among the companies analysts expect to excel: Intel (INTL) is projected to post an increase in net income of 142 percent this year. Caterpillar, a multinational that gets much of its revenue abroad, is expected to boost its net income by 47 percent this year. Analysts have also hiked their S&P 500 profit estimate for 2011 to $95.53 a share, up from $92.45 at the beginning of January, according to Bloomberg data. That would be a record, surpassing the previous high reached in 2007.

With such prospects, it's not surprising that more than half of S&P 500-listed stocks boast overall buy ratings. It is telling that the proportion has essentially held constant at both the market's October 2007 high and March 2009 low, bookends of a period that saw stocks fall by more than half. If the analysts are correct, the market would appear to be attractively priced right now. Using the $95.53 per share figure, the price-to-earnings ratio of the S&P 500 is a modest 11 as of June 9. If, however, analysts end up being too high by, say, 20 percent, the P/E would jump to almost 14.

If history is any guide, chances are good that the analysts are wrong. According to a recent McKinsey report by Marc Goedhart, Rishi Raj, and Abhishek Saxena, "Analysts have been persistently over-optimistic for 25 years," a stretch that saw them peg earnings growth at 10 percent to 12 percent a year when the actual number was ultimately 6 percent. "On average," the researchers note, "analysts' forecasts have been almost 100 percent too high," even after regulations were enacted to weed out conflicts and improve the rigor of their calculations. As the chart below shows, in most years analysts have been forced to lower their estimates after it became apparent they had set them too high.

While a few analysts, like Meredith Whitney, have made their names on bearish calls, most are chronically bullish. Part of the problem is that despite all the reforms they remain too aligned with the companies they cover. "Analysts still need to get the bulk of their information from companies, which have an incentive to be over-optimistic," says Stephen Bainbridge, a professor at UCLA Law School who specializes in the securities industry. "Meanwhile, analysts don't want to threaten that ongoing access by being too negative." Bainbridge says that with the era of the overpaid, superstar analyst long over, today's job description calls for resisting the urge to be an iconoclast. "It's a matter of herd behavior," he says.

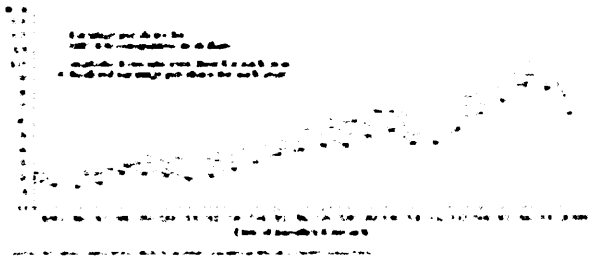
So what's a more plausible estimate of companies' earning power? Looking at factors including the strengthening dollar, which hurts exports, and higher corporate borrowing costs, David Rosenberg, chief economist at Toronto-based investment shop Gluskin Sheff + Associates, says "disappointment looms." Bernstein's Adam Parker says every 10 percent drop in the value of the euro knocks U.S. corporate earnings down by 2.5 percent to 3 percent. He sees the S&P 500 earning $86 a share next year.

As realities hit home, "It's only natural that analysts will have to revise down their views," says Todd Salamone, senior vice-president at Schaeffer's Investment Research. The market may be making its own downward adjustment, as the S&P 500 has already fallen 14 percent from its high in April. If precedent holds, analysts are bound to curb their enthusiasm belatedly, telling us next year what we really needed to know this year.

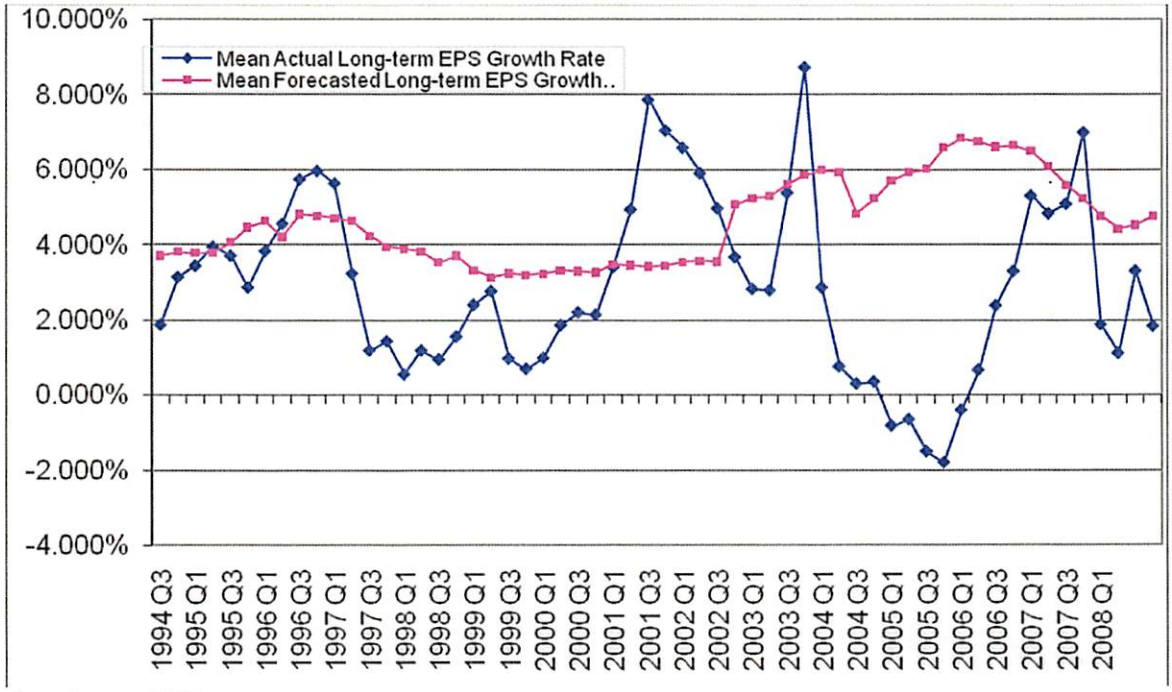
The bottom line: *Despite reforms intended to improve Wall Street research, stock analysts seem to be promoting an overly rosy view of profit prospects.*

Bloomberg Businessweek Senior Writer Farzad covers Wall Street and international finance.

The Earnings Roller Coaster

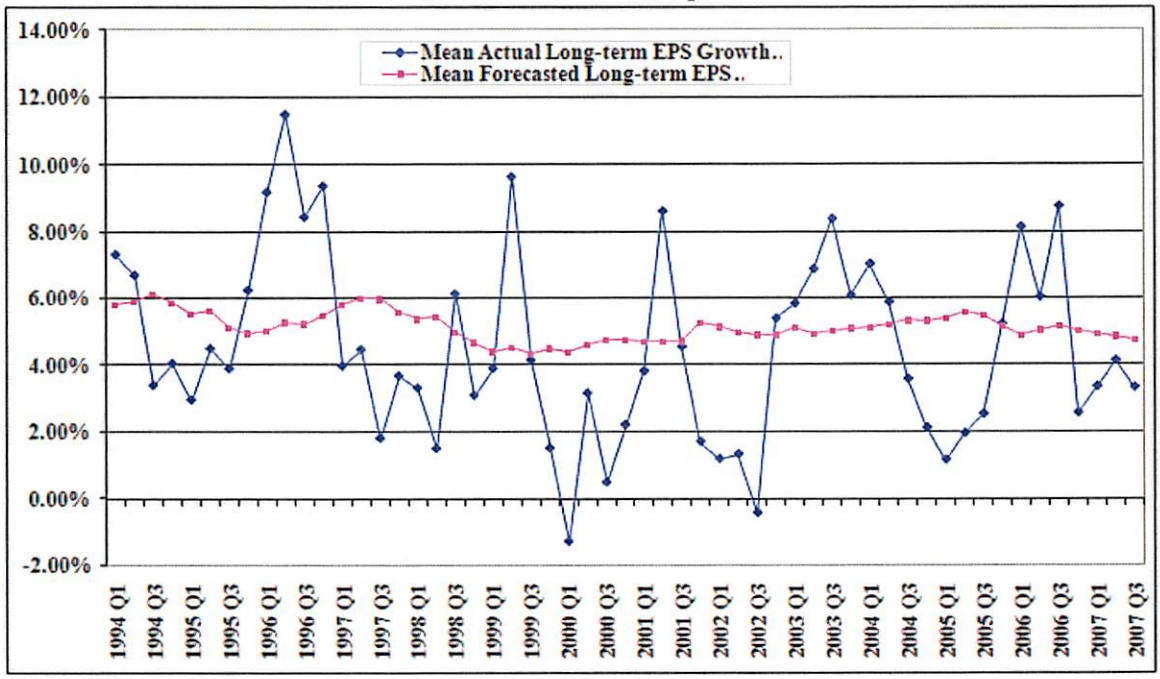


Panel A
Long-Term Forecasted Versus Actual EPS Growth Rates
Electric Utility Companies
1988-2008



Data Source: IBES

Panel B
Long-Term Forecasted Versus Actual EPS Growth Rates
Gas Distribution Companies



Panel A
Value Line 3-5 year EPS Growth Rate Forecasts

	Average Projected EPS Growth rate	Number of Negative EPS Growth Projections	Percent of Negative EPS Growth Projections
2,333 Companies	**14.70%**	**43**	**1.80%**

Value Line Investment Survey, June, 2012

Panel B
Historical Five-Year EPS Growth Rates for Value Line Companies

	Average Historical EPS Growth rate	Number with Negative Historical EPS Growth	Percent with Negative Historical EPS Growth
2,219 Companies	**3.90%**	**844**	**38.00%**

Value Line Investment Survey, June, 2012

Exhibit JRW-16
Appendix C
Building Blocks Equity Risk Premium

A. THE BUILDING BLOCKS MODEL

Ibbotson and Chen (2003) evaluate the ex post historical mean stock and bond returns in what is called the Building Blocks approach.[1] They use 75 years of data and relate the compounded historical returns to the different fundamental variables employed by different researchers in building ex ante expected equity risk premiums. Among the variables included were inflation, real earnings per share ("EPS") and dividend per share ("DPS") growth, return on equity ("ROE") and book value growth, and price-earnings ("P/E") ratios. By relating the fundamental factors to the ex post historical returns, the methodology bridges the gap between the ex post and ex ante equity risk premiums. Ilmanen (2003) illustrates this approach using the geometric returns and five fundamental variables – inflation ("CPI"), dividend yield ("D/P"), real earnings growth ("RG"), repricing gains ("PEGAIN"), and return interaction/reinvestment ("INT").[2] This is shown on page 1 of Exhibit JRW-16, Appendix C1. The first column breaks down the 1926-2000 geometric mean stock return of 10.7% into the different return components demanded by investors: the historical U.S. Treasury bond return (5.2%), the excess equity return (5.2%), and a small interaction term (0.3%). This 10.7% annual stock return over the 1926-2000 period can then be broken down into

[1] Roger Ibbotson and Peng Chen, "Long Run Returns: Participating in the Real Economy," *Financial Analysts Journal*, (January 2003).

[2] Antti Ilmanen, Expected Returns on Stocks and Bonds," *Journal of Portfolio Management*, (Winter 2003), p. 11.

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DESCRIPTION Randall Woodridge (JRW-16)
DATE APPENDIX C

Exhibit JRW-16
Appendix C
Building Blocks Equity Risk Premium

the following fundamental elements: inflation (3.1%), dividend yield (4.3%), real earnings growth (1.8%), repricing gains associated with higher P/E ratios (1.3%), and a small interaction term (0.2%).

The third column in the graph on page 1 of Exhibit JRW-16, Appendix C1 shows current inputs to estimate an ex ante expected market return. These inputs include the following:

CPI – To assess expected inflation, I have employed expectations of the short-term and long-term inflation rate. Long-term inflation forecasts are available in the Federal Reserve Bank of Philadelphia's publication entitled *Survey of Professional Forecasters*. While this survey is published quarterly, only the first quarter survey includes long-term forecasts of gross domestic product ("GDP") growth, inflation, and market returns. In the first quarter 2013 survey, published on February 15, 2013, the median long-term (10-year) expected inflation rate as measured by the CPI was 2.30% (see Panel A of page 2 of Exhibit JRW-16, Appendix C1).

The University of Michigan's Survey Research Center surveys consumers on their short-term (one-year) inflation expectations on a monthly basis. As shown on page 3 of Exhibit JRW-16, Appendix C1, the current short-term expected inflation rate is 3.0%.

Exhibit JRW-16
Appendix C
Building Blocks Equity Risk Premium

As a measure of expected inflation, I will use the average of the long-term (2.3%) and short-term (3.0%) inflation rate measures, or 2.65%.

D/P – As shown on page 4 of Exhibit JRW-16, Appendix C1, the dividend yield on the Standard and Poor's (S&P) 500 has fluctuated from 1.0% to almost 3.5% from 2000-2010. Ibbotson and Chen (2003) report that the long-term average dividend yield of the S&P 500 is 4.3%. As of October 2013, the indicated S&P 500 dividend yield was 2.1%. I will use this figure in my ex ante risk premium analysis.

RG – To measure expected real growth in earnings, I use the historical real earnings growth rate S&P 500 and the expected real GDP growth rate. The S&P 500 was created in 1960 and includes 500 companies which come from 10 different sectors of the economy. On page 5 of Exhibit JRW-16, Appendix C1, real EPS growth is computed using the CPI as a measure of inflation. The real growth figure over the 1960-2011 period for the S&P 500 is 2.8%.

The second input for expected real earnings growth is expected real GDP growth. The rationale is that, over the long-term, corporate profits have averaged 5.50% of U.S. GDP.[3] Expected GDP growth, according to the

[3]Marc. H. Goedhart, et al, "The Real Cost of Equity," *McKinsey on Finance* (Autumn 2002), p.14.

Exhibit JRW-16
Appendix C
Building Blocks Equity Risk Premium

Federal Reserve Bank of Philadelphia's *Survey of Professional Forecasters,* is 2.64% (see Panel B of page 2 of Exhibit JRW-16, Appendix C1).

Given these results, I will use 2.75% for real earnings growth.

PEGAIN – PEGAIN is the repricing gain associated with an increase in the P/E ratio. It accounted for 1.3% of the 10.7% annual stock return in the 1926-2000 period. In estimating an ex ante expected stock market return, one issue is whether investors expect P/E ratios to increase from their current levels. The P/E ratios for the S&P 500 over the past 25 years are shown on page 4 of Exhibit JRW-16, Appendix C1. The run-up and eventual peak in P/Es in the year 1999 is very evident in the chart. The average P/E declined until late 2006, and then increased to still higher levels, primarily due to the decline in EPS as a result of the financial crisis and the recession. As of October 2013, the average P/E for the S&P 500 was 15.5X, which is in line with the historic average. Since the current figure is near the historic average, a PEGAIN would not be appropriate in estimating an ex ante expected stock market return.

Expected Return from Building Blocks Approach - The current expected market return is represented by the last column on the right in the graph entitled "Decomposing Equity Market Returns: The Building Blocks Methodology" set forth on page 1 of Exhibit JRW-16, Appendix C1. As

Exhibit JRW-16
Appendix C
Building Blocks Equity Risk Premium

shown, the expected market return of 7.50% is composed of 2.65% expected inflation, 2.10% dividend yield, and 2.75% real earnings growth rate.

This expected return of 7.50% is consistent with other expected return forecasts.

1. In the first quarter 2013 *Survey of Financial Forecasters*, published on February 15, 2013 by the Federal Reserve Bank of Philadelphia, the median long-term expected return on the S&P 500 was 6.13% (see Panel D of page 2 of Exhibit JRW-16, Appendix C1).
2. John Graham and Campbell Harvey of Duke University conduct a quarterly survey of corporate CFOs. The survey is a joint project of Duke University and *CFO Magazine*. In the June 2013 survey, the mean expected return on the S&P 500 over the next 10 years was 6.70%.[4]

B. THE BUILDING BLOCKS EQUITY RISK PREMIUM

The current 30-year U.S. Treasury yield is 3.50%. This ex ante equity risk premium is simply the expected market return from the Building Blocks methodology minus this risk-free rate:

[4] The survey results are available at www.cfosurvey.org.

Exhibit JRW-16
Appendix C
Building Blocks Equity Risk Premium

Ex Ante Equity Risk Premium = 7.50% - 3.50% = 4.00%

This is only one estimate of the equity risk premium. As shown on page 6 of Exhibit JRW-11, I am also using the results of other studies and surveys to determine an equity risk premium for my Capital Asset Pricing Model ("CAPM").

Exhibit JRW-16, Appendix C1

Decomposing Equity Market Returns
The Building Blocks Methodology

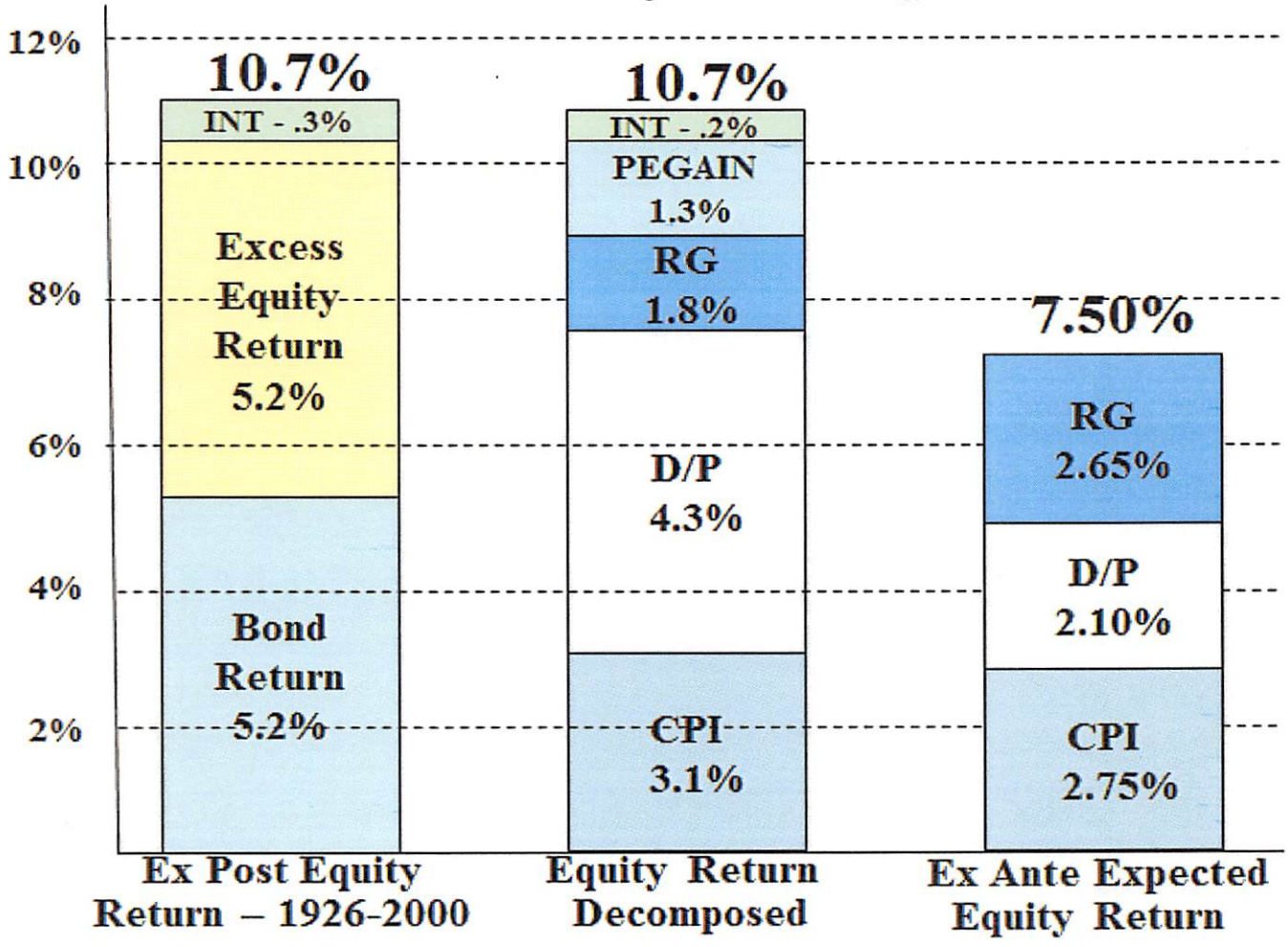


Exhibit JRW-16, Appendix C1

2013 Survey of Professional Forecasters
Philadelphia Federal Reserve Bank
Long-Term Forecasts

Table Seven
LONG-TERM (10 YEAR) FORECASTS

Panel A

SERIES: CPI INFLATION RATE	
STATISTIC	
MINIMUM	0.97
LOWER QUARTILE	2.05
MEDIAN	2.30
UPPER QUARTILE	2.60
MAXIMUM	3.50
MEAN	2.33
STD. DEV.	0.45
N	39
MISSING	7

Panel B

SERIES: REAL GDP GROWTH RATE	
STATISTIC	
MINIMUM	1.90
LOWER QUARTILE	2.50
MEDIAN	2.64
UPPER QUARTILE	2.90
MAXIMUM	3.75
MEAN	2.67
STD. DEV.	0.41
N	37
MISSING	8

Panel C

SERIES: PRODUCTIVITY GROWTH	
STATISTIC	
MINIMUM	0.90
LOWER QUARTILE	1.50
MEDIAN	1.80
UPPER QUARTILE	2.20
MAXIMUM	3.00
MEAN	1.86
STD. DEV.	0.51
N	30.00
MISSING	16

Panel D

SERIES: STOCK RETURNS (S&P 500)	
STATISTIC	
MINIMUM	4.00
LOWER QUARTILE	5.05
MEDIAN	6.13
UPPER QUARTILE	6.95
MAXIMUM	10.00
MEAN	6.15
STD. DEV.	1.58
N	24
MISSING	22

Panel E

SERIES: BOND RETURNS (10-YEAR)	
STATISTIC	
MINIMUM	1.90
LOWER QUARTILE	2.75
MEDIAN	3.83
UPPER QUARTILE	4.30
MAXIMUM	7.00
MEAN	3.70
STD. DEV.	1.32
N	26.00
MISSING	20

Panel F

SERIES: BILL RETURNS (3-MONTH)	
STATISTIC	
MINIMUM	0.50
LOWER QUARTILE	1.80
MEDIAN	2.40
UPPER QUARTILE	2.85
MAXIMUM	4.25
MEAN	2.46
STD. DEV.	0.98
N	25
MISSING	21

Source: Philadelphia Federal Reserve Bank, Survey of Professional Forecasters, February 15, 2013.

Exhibit JRW-16, Appendix C1

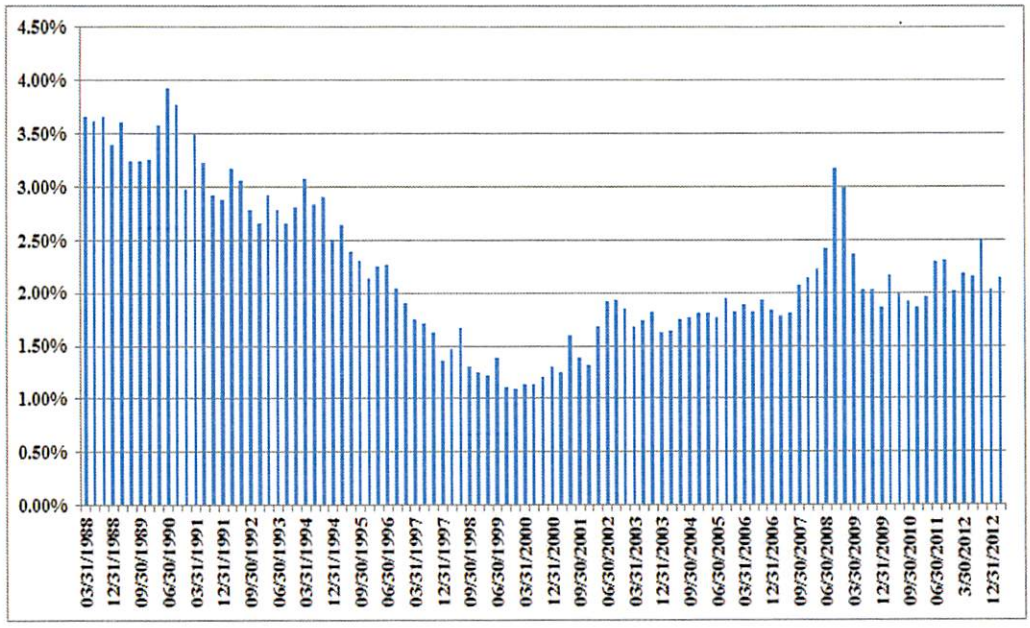
University of Michigan Survey Research Center
Expected Short-Term Inflation Rate

Data Source: http://research.stlouisfed.org/fred2/series/MICH?cid=98

Exhibit JRW-16, Appendix C1

Decomposing Equity Market Returns
The Building Blocks Methodology

S&P 500 Dividend Yield



S&P 500 P/E Ratio

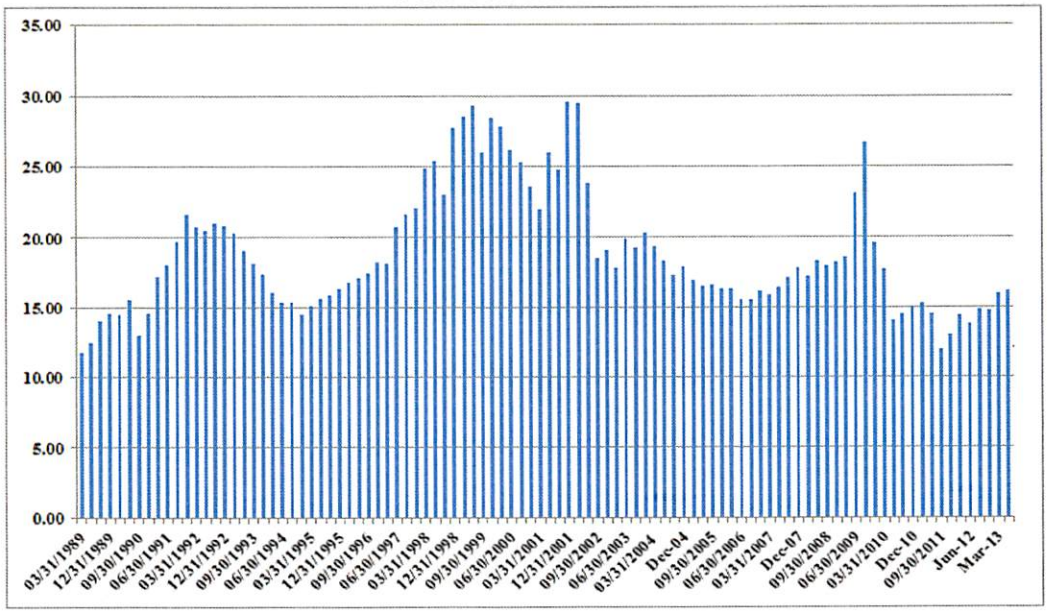


Exhibit JRW-16, Appendix C1

Real S&P 500 EPS Growth Rate

Year	S&P 500 EPS	Annual Inflation CPI	Inflation Adjustment Factor	Real S&P 500 EPS	
1960	3.10	1.48		3.10	
1961	3.37	0.07	1.01	3.35	
1962	3.67	1.22	1.02	3.59	
1963	4.13	1.65	1.04	3.99	
1964	4.76	1.19	1.05	4.55	
1965	5.30	1.92	1.07	4.97	
1966	5.41	3.35	1.10	4.90	
1967	5.46	3.04	1.14	4.80	
1968	5.72	4.72	1.19	4.81	
1969	6.10	6.11	1.26	4.83	10-Year
1970	5.51	5.49	1.34	4.13	2.89%
1971	5.57	3.36	1.38	4.04	
1972	6.17	3.41	1.43	4.33	
1973	7.96	8.80	1.55	5.13	
1974	9.35	12.20	1.74	5.37	
1975	7.71	7.01	1.86	4.14	
1976	9.75	4.81	1.95	4.99	
1977	10.87	6.77	2.08	5.22	
1978	11.64	9.03	2.27	5.13	
1979	14.55	13.31	2.57	5.66	10-Year
1980	14.99	12.40	2.89	5.18	2.30%
1981	15.18	8.94	3.15	4.82	
1982	13.82	3.87	3.27	4.23	
1983	13.29	3.80	3.40	3.91	
1984	16.84	3.95	3.53	4.77	
1985	15.68	3.77	3.66	4.28	
1986	14.43	1.13	3.70	3.90	
1987	16.04	4.41	3.87	4.15	
1988	22.77	4.42	4.04	5.64	
1989	24.03	4.65	4.22	5.69	10-Year
1990	21.73	6.11	4.48	4.85	-0.65%
1991	19.10	3.06	4.62	4.14	
1992	18.13	2.90	4.75	3.81	
1993	19.82	2.75	4.88	4.06	
1994	27.05	2.67	5.01	5.40	
1995	35.35	2.54	5.14	6.88	
1996	35.78	3.32	5.31	6.74	
1997	39.56	1.70	5.40	7.33	
1998	38.23	1.61	5.48	6.97	
1999	45.17	2.68	5.63	8.02	10-Year
2000	52.00	3.39	5.82	8.93	6.29%
2001	44.23	1.55	5.92	7.48	
2002	47.24	2.38	6.06	7.80	
2003	54.15	1.88	6.17	8.77	
2004	67.01	3.26	6.37	10.51	
2005	68.32	3.42	6.60	10.35	
2006	81.96	2.54	6.77	12.11	
2007	87.51	4.08	7.04	12.43	
2008	65.39	0.09	7.05	9.28	
2009	59.65	2.72	7.24	8.24	10-Year
2010	83.66	1.50	7.35	11.39	2.46%
2011	97.05	2.96	7.57	12.83	
Data Source: http://pages.stern.nyu.edu/~adamodar/				Real EPS Growth	2.8%

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Appendix D
The Use of Historical Returns to Measure an Expected Risk Premium

It is quite common for analysts to estimate an equity or market risk premium as the difference between historical stock and bond returns. However, using the historical relationship between stock and bond returns to measure an ex ante equity risk premium can produce an inflated measure of the true market or equity risk premium. The equity risk premium is based on expectations of the future. When past market conditions vary significantly from the present, historic data does not provide a realistic or accurate barometer of future expectations. More significantly, there are a number of empirical issues that can result in historical returns being poor measures of the expected risk premium.

There are a number of issues in using historic returns over long time periods to estimate expected equity risk premiums. These issues include:

(A) Biased historical bond returns

(B) Use of the arithmetic versus the geometric mean return

(C) The large error in measuring the equity risk premium using historical returns

(D) Unattainable and biased historical stock returns

(E) Company Survivorship bias

(F) The "Peso Problem" - U.S. stock market survivorship bias

These issues will be addressed in order.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130140-EI EXHIBIT 63
PARTY Office of Public Counsel (OPC) Direct
DESCRIPTION Randall Woodridge (JRW-16)
DATE APPENDIX D

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Appendix D
The Use of Historical Returns to Measure an Expected Risk Premium

A. Biased Historical Bond Returns

An essential assumption of this approach is that over long periods of time, investors' expectations are realized. However, the experienced returns of bondholders in the past invalidate this critical assumption. Historic bond returns are biased downward as a measure of expectancy because of capital losses suffered by bondholders in the past. As such, risk premiums derived from this data are biased upwards.

B. The Arithmetic versus the Geometric Mean Return

The measure of investment return has a significant effect on the interpretation of the risk premium results. When analyzing a single security price series over time (i.e., a time series), the best measure of investment performance is the geometric mean return. Using the arithmetic mean overstates the return experienced by investors. In a study entitled "Risk and Return on Equity: The Use and Misuse of Historical Estimates," Carleton and Lakonishok make the following observation: "The geometric mean measures the changes in wealth over more than one period on a buy and hold (with dividends invested) strategy."[1] When a historic stock and bond return study covers more than one period (and he assumes that dividends are reinvested), he should be employing the geometric

[1] Willard T. Carleton and Josef Lakonishok, "Risk and Return on Equity: The Use and Misuse of Historical Estimates," *Financial Analysts Journal*, pp. 38-47, (January-February, 1985).

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mean and not the arithmetic mean.

To demonstrate the upward bias of the arithmetic mean, consider the following example. Assume that you have a stock (that pays no dividend) that is selling for $100 today, then it increases to $200 in one year, and then falls back to $100 in two years. The table below shows the prices and returns.

Time Period	Stock Price	Annual Return
0	$100	
1	$200	100%
2	$100	-50%

The arithmetic mean return is simply (100% + (-50%))/2 = 25% per year. The geometric mean return is $((2 * .50)^{(1/2)}) - 1 = 0\%$ per year. Therefore, the arithmetic mean return suggests that your stock has appreciated at an annual rate of 25%, while the geometric mean return indicates an annual return of 0%. Since after two years, your stock is still only worth $100, the geometric mean return is the appropriate return measure. For this reason, when stock returns and earnings growth rates are reported in the financial press, they are generally reported using the geometric mean. This is because of the upward bias of the arithmetic mean. As further evidence of the appropriate mean return measure, the Securities Exchange Commission ("SEC") requires equity mutual funds to report historic return performance using geometric mean and not arithmetic mean returns.[2] Therefore, the historic arithmetic mean return measures are biased and should be disregarded.

[2] SEC, Form N-1A.

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Appendix D
The Use of Historical Returns to Measure an Expected Risk Premium

Nonetheless, in measuring historic returns to develop an expected equity risk premium, finance texts will often recommend the use of an arithmetic mean return as a measure of central tendency. A common justification for using the arithmetic mean return is that since annual stock returns are not serially correlated, the best measure of a return for the next year is the arithmetic mean of past returns. On the other hand, Damodaran suggests that such an estimate is not appropriate in estimating an equity risk premium:[3]

> "There are, however, strong arguments that can be made for the use of geometric averages. First, empirical studies seem to indicate that returns on stocks are negatively correlated over long periods of time. Consequently, the arithmetic average return is likely to overstate the premium. Second, while asset pricing models may be single period models, the use of these models to get expected returns over long periods (such as five or ten years) suggests that the estimation period may be much longer than a year. In this context, the argument for geometric average premiums becomes stronger."

C. The Error in Measuring Equity Risk Premiums with Historic Data

Measuring the equity risk premium using historical stock and bond returns is subject to a substantial forecasting error. For example, the arithmetic mean long-term equity risk premium of approximately 6.5% has a standard deviation of over 20%. This may be interpreted in the following way with respect to the historical distribution of the long-term equity risk premium using a standard normal distribution and a 95%, +/- 2 standard deviation confidence interval: we can say, with a 95% degree of confidence, that the true equity risk premium is between -34.7% and +47.7%. As such, the historical equity risk premium is measured with a

[3] Aswath. Damodaran, "Equity Risk Premiums (ERP): Determinants, Estimation and Implications – The 2013 Edition" NYU Working Paper, 2013, p. 27.

substantial amount of error.

D. Unattainable and Biased Historic Stock Returns

Returns developed using Ibbotson's methodology are computed on stock indexes and therefore: (1) cannot be reflective of expectations because these returns are unattainable to investors and (2) produce biased results. This methodology assumes: (1) monthly portfolio rebalancing and (2) reinvestment of interest and dividends. Monthly portfolio rebalancing presumes that investors rebalance their portfolios at the end of each month in order to have an equal dollar amount invested in each security at the beginning of each month. The assumption generates high transaction costs and thereby renders these returns unattainable to investors. In addition, an academic study demonstrates that the monthly portfolio rebalancing assumption produces biased estimates of stock returns.[4]

Transaction costs themselves provide another bias in historic versus expected returns. In the past, the observed stock returns were not the realized returns of investors, due to the much higher transaction costs of previous decades. These higher transaction costs are reflected through the higher commissions on stock trades and the lack of low-cost mutual funds like index funds.

E. Company Survivorship Bias

[4] See Richard Roll, "On Computing Mean Returns and the Small Firm Premium," *Journal of Financial Economics*, pp. 371-86, (1983).

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The Use of Historical Returns to Measure an Expected Risk Premium

Using historic data to estimate an equity risk premium suffers from company survivorship bias. Company survivorship bias results when using returns from indexes like the S&P 500. The S&P 500 includes only companies that have survived. The fact that returns of firms that did not perform well were dropped from these indexes is not reflected. Therefore, these stock returns are upwardly biased because they only reflect the returns from more successful companies.

F. The "Peso Problem" - U.S. Stock Market Survivorship Bias

The use of historic return data also suffers from the so-called "Peso Problem," which is also known as "U.S. stock market survivorship bias." The "peso problem" issue was first highlighted by the Nobel laureate, Milton Friedman, and gets its name from conditions related to the Mexican peso market in the early 1970s. This issue involves the fact that past stock market returns were higher than were expected at the time because despite war, depression and other social, political, and economic events, the U.S. economy survived and did not suffer hyperinflation, invasion, and/or the calamities of other countries. As such, highly improbable events, which may or may not occur in the future, are factored into stock prices, leading to seemingly low valuations. Higher than expected stock returns are then earned when these events do not subsequently occur. Therefore, the "peso problem" indicates that historic stock returns are overstated

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as measures of expected returns because the U.S. markets have not experienced the disruptions of other major markets around the world.

. One of the Biggest Mistakes in Teaching Finance

Jay Ritter, a Professor of Finance at the University of Florida, identified the use of historical stock and bond return data to estimate a forward-looking equity risk premium as one of the "Biggest Mistakes" taught by the finance profession.[5] His argument is based on the theory behind the equity risk premium, the excessive results produced by historical returns, and the previously discussed errors such as survivorship bias in historical data.

[5] Jay Ritter, "The Biggest Mistakes We Teach," *Journal of Financial Research* (Summer 2002).

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EXPERIENCE

July 2007 – Present
Wal-Mart Stores, Inc., Bentonville, AR
Senior Manager, Energy Regulatory Analysis (June 2011 – Present)
Manager, State Rate Proceedings (July 2007 – June 2011)

June 2003 – July 2007
Public Utility Commission of Oregon, Salem, OR
Senior Utility Analyst (February 2006 – July 2007)
Economist (June 2003 – February 2006)

January 2003 - May 2003
North Harris College, Houston, TX
Adjunct Instructor, Microeconomics

June 2001 - March 2003
Econ One Research, Inc., Houston, TX
Senior Analyst (October 2002 – March 2003)
Analyst (June 2001 – October 2002)

EDUCATION

2001	**Louisiana State University**	M.S., Agricultural Economics
1997-1998	**University of Florida**	Graduate Coursework, Agricultural Education and Communication
1997	**Texas A&M University**	B.S., Agricultural Development B.S., Horticulture

TESTIMONY BEFORE REGULATORY COMMISSIONS

2013

Public Utility Commission of Oregon Docket No. UE 267: In the Matter of PACIFICORP, dba PACIFIC POWER, Transition Adjustment, Five-Year Cost of Service Opt-Out.

Illinois Commerce Commission Docket No. 13-0387: Commonwealth Edison Company Tariff Filing to Present the Illinois Commerce Commission with an Opportunity to Consider Revenue Neutral Tariff Changes Related to Rate Design Authorized by Subsection 16-108.5 of the Public Utilities Act.

Iowa Utilities Board Docket No. RPU-2013-0004: In Re: MidAmerican Energy Company.

South Dakota Public Utilities Commission Docket No. EL12-061: In the Matter of the Application of Black Hills Power, Inc. for Authority to Increase its Electric Rates. (filed with confidential stipulation)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130140-EI EXHIBIT 64
PARTY Wal-Mart Stores East, LP and Sam's East, Inc. (Walmart) Direct
DESCRIPTION Steve W. Chriss (SWC-1)
DATE

Kansas Corporation Commission Docket No. 13-WSEE-629-RTS: In the Matter of the Applications of Westar Energy, Inc. and Kansas Gas and Electric Company for Approval to Make Certain Changes in their Charges for Electric Service.

Public Utility Commission of Oregon Docket No. UE 263: In the Matter of PACIFICORP, dba PACIFIC POWER, Request for a General Rate Revision.

Arkansas Public Service Commission Docket No. 13-028-U: In the Matter of the Application of Entergy Arkansas, Inc. for Approval of Changes in Rates for Retail Electric Service.

Virginia State Corporation Commission Docket No. PUE-2013-00020: Application of Virginia Electric and Power Company for a 2013 Biennial Review of the Rates, Terms, and Conditions for the Provision of Generation, Distribution, and Transmission Services Pursuant to § 56-585.1 A of the Code of Virginia.

Florida Public Service Commission Docket No. 130040-EI: Petition for Rate Increase by Tampa Electric Company.

South Carolina Public Service Commission Docket No. 2013-59-E: Application of Duke Energy Carolinas, LLC, for Authority to Adjust and Increase Its Electric Rates and Charges.

Public Utility Commission of Oregon Docket No. UE 262: In the Matter of PORTLAND GENERAL ELECTRIC COMPANY, Request for a General Rate Revision.

New Jersey Board of Public Utilities Docket No. ER12111052: In the Matter of the Verified Petition of Jersey Central Power & Light Company For Review and Approval of Increases in and Other Adjustments to Its Rates and Charges For Electric Service, and For Approval of Other Proposed Tariff Revisions in Connection Therewith; and for Approval of an Accelerated Reliability Enhancement Program ("2012 Base Rate Filing")

North Carolina Utilities Commission Docket No. E-7, Sub 1026: In the Matter of the Application of Duke Energy Carolinas, LLC for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina.

Public Utility Commission of Oregon Docket No. UE 264: PACIFICORP, dba PACIFIC POWER, 2014 Transition Adjustment Mechanism.

Public Utilities Commission of California Docket No. 12-12-002: Application of Pacific Gas and Electric Company for 2013 Rate Design Window Proceeding.

Public Utilities Commission of Ohio Docket Nos. 12-426-EL-SSO, 12-427-EL-ATA, 12-428-EL-AAM, 12-429-EL-WVR, and 12-672-EL-RDR: In the Matter of the Application of the Dayton Power and Light Company Approval of its Market Offer.

Minnesota Public Utilities Commission Docket No. E-002/GR-12-961: In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in Minnesota.

North Carolina Utilities Commission Docket E-2, Sub 1023: In the Matter of Application of Progress Energy Carolinas, Inc. For Adjustment of Rates and Charges Applicable to Electric Service in North Carolina.

2012

Public Utility Commission of Texas Docket No. 40443: Application of Southwestern Electric Power Company for Authority to Change Rates and Reconcile Fuel Costs.

South Carolina Public Service Commission Docket No. 2012-218-E: Application of South Carolina Electric & Gas Company for Increases and Adjustments in Electric Rate Schedules and Tariffs and Request for Mid-Period Reduction in Base Rates for Fuel.

Kansas Corporation Commission Docket No. 12-KCPE-764-RTS: In the Matter of the Application of Kansas City Power & Light Company to Make Certain Changes in its Charges for Electric Service.

Kansas Corporation Commission Docket No. 12-GIMX-337-GIV: In the Matter of a General Investigation of Energy-Efficiency Policies for Utility Sponsored Energy Efficiency Programs.

Florida Public Service Commission Docket No. 120015-EI: In Re: Petition for Rate Increase by Florida Power & Light Company.

California Public Utilities Commission Docket No. A.11-10-002: Application of San Diego Gas & Electric Company (U 902 E) for Authority to Update Marginal Costs, Cost Allocation, and Electric Rate Design.

Utah Public Service Commission Docket No. 11-035-200: In the Matter of the Application of Rocky Mountain Power for Authority to Increase its Retail Electric Utility Service Rates in Utah and for Approval of its Proposed Electric Service Schedules and Electric Service Regulations.

Virginia State Corporation Commission Case No. PUE-2012-00051: Application of Appalachian Power Company to Revise its Fuel Factor Pursuant to § 56-249.6 of the Code of Virginia.

Public Utilities Commission of Ohio Case Nos. 11-346-EL-SSO, 11-348-EL-SSO, 11-349-EL-AAM, and 11-350-EL-AAM: In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Authority to Establish a Standard Service Offer Pursuant to Section 4928.143, Revised Code, in the Form on an Electric Security Plan and In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Approval of Certain Accounting Authority.

New Jersey Board of Public Utilities Docket No. ER11080469: In the Matter of the Petition of Atlantic City Electric for Approval of Amendments to Its Tariff to Provide for an Increase in Rates and Charges for Electric Service Pursuant to N.J.S.A. 48:2-21 and N.J.S.A. 48:2-21.1 and For Other Appropriate Relief.

Public Utility Commission of Texas Docket No. 39896: Application of Entergy Texas, Inc. for Authority to Change Rates and Reconcile Fuel Costs.

Missouri Public Service Commission Case No. EO-2012-0009: In the Matter of KCP&L Greater Missouri Operations Notice of Intent to File an Application for Authority to Establish a Demand-Side Programs Investment Mechanism.

Colorado Public Utilities Commission Docket No. 11AL-947E: In the Matter of Advice Letter No. 1597-Electric Filed by Public Service Company of Colorado to Revise its Colorado PUC No. 7-Electric Tariff to Implement a General Rate Schedule Adjustment and Other Changes Effective December 23, 2011.

Illinois Commerce Commission Docket No. 11-0721: Commonwealth Edison Company Tariffs and Charges Submitted Pursuant to Section 16-108.5 of the Public Utilities Act.

Public Utility Commission of Texas Docket No. 38951: Application of Entergy Texas, Inc. for Approval of Competitive Generation Service tariff (Issues Severed from Docket No. 37744).
California Public Utilities Commission Docket No. A.11-06-007: Southern California Edison's General Rate Case, Phase 2.

2011

Arizona Corporation Commission Docket No. E-01345A-11-0224: In the Matter of Arizona Public Service Company for a Hearing to Determine the Fair Value of Utility Property of the Company for Ratemaking Purposes, to Fix and Just and Reasonable Rate of Return Thereon, to Approve Rate Schedules Designed to Develop Such Return.

Oklahoma Corporation Commission Cause No. PUD 201100087: In the Matter of the Application of Oklahoma Gas and Electric Company for an Order of the Commission Authorizing Applicant to Modify its Rates, Charges, and Tariffs for Retail Electric Service in Oklahoma.

South Carolina Public Service Commission Docket No. 2011-271-E: Application of Duke Energy Carolinas, LLC for Authority to Adjust and Increase its Electric Rates and Charges.

Pennsylvania Public Utility Commission Docket No. P-2011-2256365: Petition of PPL Electric Utilities Corporation for Approval to Implement Reconciliation Rider for Default Supply Service.

North Carolina Utilities Commission Docket No. E-7, Sub 989: In the Matter of Application of Duke Energy Carolinas, LLC for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina.

Florida Public Service Commission Docket No. 110138: In Re: Petition for Increase in Rates by Gulf Power Company.

Public Utilities Commission of Nevada Docket No. 11-06006: In the Matter of the Application of Nevada Power Company, filed pursuant to NRS 704.110(3) for authority to increase its annual revenue requirement for general rates charged to all classes of customers to recover the costs of constructing the Harry Allen Combined Cycle plant and other generating, transmission, and distribution plant additions, to reflect changes in the cost of capital, depreciation rates and cost of service, and for relief properly related thereto.

North Carolina Utilities Commission Docket Nos. E-2, Sub 998 and E-7, Sub 986: In the Matter of the Application of Duke Energy Corporation and Progress Energy, Inc., to Engage in a Business Combination Transaction and to Address Regulatory Conditions and Codes of Conduct.

Public Utilities Commission of Ohio Case Nos. 11-346-EL-SSO, 11-348-EL-SSO, 11-349-EL-AAM, and 11-350-EL-AAM: In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Authority to Establish a Standard Service Offer Pursuant to Section 4928.143, Revised Code, in the Form on an Electric Security Plan and In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Approval of Certain Accounting Authority.

Virginia State Corporation Commission Case No. PUE-2011-00037: In the Matter of Appalachian Power Company for a 2011 Biennial Review of the Rates, Terms, and Conditions for the Provision of Generation, Distribution, and Transmission Services Pursuant to § 56-585.1 A of the Code of Virginia.

Illinois Commerce Commission Docket No. 11-0279 and 11-0282 (cons.): Ameren Illinois Company Proposed General Increase in Electric Delivery Service and Ameren Illinois Company Proposed General Increase in Gas Delivery Service.

Virginia State Corporation Commission Case No. PUE-2011-00045: Application of Virginia Electric and Power Company to Revise its Fuel Factor Pursuant to § 56-249.6 of the Code of Virginia.

Utah Public Service Commission Docket No. 10-035-124: In the Matter of the Application of Rocky Mountain Power for Authority to Increase its Retail Electric Utility Service Rates in Utah and for Approval of its Proposed Electric Service Schedules and Electric Service Regulations.

Maryland Public Utilities Commission Case No. 9249: In the Matter of the Application of Delmarva Power & Light for an Increase in its Retail Rates for the Distribution of Electric Energy.

Minnesota Public Utilities Commission Docket No. E002/GR-10-971: In the Matter of the Application of Northern States Power Company d/b/a Xcel Energy for Authority to Increase Rates for Electric Service in Minnesota.

Michigan Public Service Commission Case No. U-16472: In the Matter of the Detroit Edison Company for Authority to Increase its Rates, Amend its Rate Schedules and Rules Governing the Distribution and Supply of Electric Energy, and for Miscellaneous Accounting Authority.

2010

Public Utilities Commission of Ohio Docket No. 10-2586-EL-SSO: In the Matter of the Application of Duke Energy Ohio for Approval of a Market Rate Offer to Conduct a Competitive Bidding Process for Standard Service Offer Electric Generation Supply, Accounting Modifications, and Tariffs for Generation Service.

Colorado Public Utilities Commission Docket No. 10A-554EG: In the Matter of the Application of Public Service Company of Colorado for Approval of a Number of Strategic Issues Relating to its DSM Plan, Including Long-Term Electric Energy Savings Goals, and Incentives.

Public Service Commission of West Virginia Case No. 10-0699-E-42T: Appalachian Power Company and Wheeling Power Company Rule 42T Application to Increase Electric Rates.

Oklahoma Corporation Commission Cause No. PUD 201000050: Application of Public Service Company of Oklahoma, an Oklahoma Corporation, for an Adjustment in its Rates and Charges and Terms and Conditions of Service for Electric Service in the State of Oklahoma.

Georgia Public Service Commission Docket No. 31958-U: In Re: Georgia Power Company's 2010 Rate Case.

Washington Utilities and Transportation Commission Docket No. 100749: 2010 Pacific Power & Light Company General Rate Case.

Colorado Public Utilities Commission Docket No. 10M-254E: In the Matter of Commission Consideration of Black Hills Energy's Plan in Compliance with House Bill 10-1365, "Clean Air-Clean Jobs Act."

Colorado Public Utilities Commission Docket No. 10M-245E: In the Matter of Commission Consideration of Public Service Company of Colorado Plan in Compliance with House Bill 10-1365, "Clean Air-Clean Jobs Act."

Public Service Commission of Utah Docket No. 09-035-15 *Phase II*: In the Matter of the Application of Rocky Mountain Power for Approval of its Proposed Energy Cost Adjustment Mechanism.

Public Utility Commission of Oregon Docket No. UE 217: In the Matter of PACIFICORP, dba PACIFIC POWER Request for a General Rate Revision.

Mississippi Public Service Commission Docket No. 2010-AD-57: In Re: Proposal of the Mississippi Public Service Commission to Possibly Amend Certain Rules of Practice and Procedure.

Indiana Utility Regulatory Commission Cause No. 43374: Verified Petition of Duke Energy Indiana, Inc. Requesting the Indiana Utility Regulatory Commission to Approve an Alternative Regulatory Plan Pursuant to Ind. Code § 8-1-2.5-1, *ET SEQ.*, for the Offering of Energy Efficiency Conservation, Demand Response, and Demand-Side Management Programs and Associated Rate Treatment Including Incentives Pursuant to a Revised Standard Contract Rider No. 66 in Accordance with Ind. Code §§ 8-1-2.5-1 *ET SEQ.* and 8-1-2-42 (a); Authority to Defer Program Costs Associated with its Energy Efficiency Portfolio of Programs; Authority to Implement New and Enhanced Energy Efficiency Programs, Including the Powershare® Program in its Energy Efficiency Portfolio of Programs; and Approval of a Modification of the Fuel Adjustment Clause Earnings and Expense Tests.

Public Utility Commission of Texas Docket No. 37744: Application of Entergy Texas, Inc. for Authority to Change Rates and to Reconcile Fuel Costs.

South Carolina Public Service Commission Docket No. 2009-489-E: Application of South Carolina Electric & Gas Company for Adjustments and Increases in Electric Rate Schedules and Tariffs.

Kentucky Public Service Commission Case No. 2009-00459: In the Matter of General Adjustments in Electric Rates of Kentucky Power Company.

Virginia State Corporation Commission Case No. PUE-2009-00125: For acquisition of natural gas facilities Pursuant to § 56-265.4:5 B of the Virginia Code.

Arkansas Public Service Commission Docket No. 10-010-U: In the Matter of a Notice of Inquiry Into Energy Efficiency.

Connecticut Department of Public Utility Control Docket No. 09-12-05: Application of the Connecticut Light and Power Company to Amend its Rate Schedules.

Arkansas Public Service Commission Docket No. 09-084-U: In the Matter of the Application of Entergy Arkansas, Inc. For Approval of Changes in Rates for Retail Electric Service.

Missouri Public Service Commission Docket No. ER-2010-0036: In the Matter of Union Electric Company d/b/a AmerenUE for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in the Company's Missouri Service Area.

Public Service Commission of Delaware Docket No. 09-414: In the Matter of the Application of Delmarva Power & Light Company for an Increase in Electric Base Rates and Miscellaneous Tariff Charges.

2009

Virginia State Corporation Commission Case No. PUE-2009-00030: In the Matter of Appalachian Power Company for a Statutory Review of the Rates, Terms, and Conditions for the Provision of Generation, Distribution, and Transmission Services Pursuant to § 56-585.1 A of the Code of Virginia.

Public Service Commission of Utah Docket No. 09-035-15 *Phase I*: In the Matter of the Application of Rocky Mountain Power for Approval of its Proposed Energy Cost Adjustment Mechanism.

Public Service Commission of Utah Docket No. 09-035-23: In the Matter of the Application of Rocky Mountain Power for Authority To Increase its Retail Electric Utility Service Rates in Utah and for Approval of Its Proposed Electric Service Schedules and Electric Service Regulations.

Colorado Public Utilities Commission Docket No. 09AL-299E: Re: The Tariff Sheets Filed by Public Service Company of Colorado with Advice Letter No. 1535 – Electric.

Arkansas Public Service Commission Docket No. 09-008-U: In the Matter of the Application of Southwestern Electric Power Company for Approval of a General Change in Rates and Tariffs.

Oklahoma Corporation Commission Docket No. PUD 200800398: In the Matter of the Application of Oklahoma Gas and Electric Company for an Order of the Commission Authorizing Applicant to Modify its Rates, Charges, and Tariffs for Retail Electric Service in Oklahoma.

Public Utilities Commission of Nevada Docket No. 08-12002: In the Matter of the Application by Nevada Power Company d/b/a NV Energy, filed pursuant to NRS §704.110(3) and NRS §704.110(4) for authority to increase its annual revenue requirement for general rates charged to all classes of customers, begin to recover the costs of acquiring the Bighorn Power Plant, constructing the Clark Peakers, Environmental Retrofits and other generating, transmission and distribution plant additions, to reflect changes in cost of service and for relief properly related thereto.

New Mexico Public Regulation Commission Case No. 08-00024-UT: In the Matter of a Rulemaking to Revise NMPRC Rule 17.7.2 NMAC to Implement the Efficient Use of Energy Act.

Indiana Utility Regulatory Commission Cause No. 43580: Investigation by the Indiana Utility Regulatory Commission, of Smart Grid Investments and Smart Grid Information Issues Contained in 111(d) of the Public Utility Regulatory Policies Act of 1978 (16 U.S.C. § 2621(d)), as Amended by the Energy Independence and Security Act of 2007.

Louisiana Public Service Commission Docket No. U-30192 *Phase II (February 2009)*: Ex Parte, Application of Entergy Louisiana, LLC for Approval to Repower Little Gypsy Unit 3 Electric Generating Facility and for Authority to Commence Construction and for Certain Cost Protection and Cost Recovery.

South Carolina Public Service Commission Docket No. 2008-251-E: In the Matter of Progress Energy Carolinas, Inc.'s Application For the Establishment of Procedures to Encourage Investment in Energy Efficient Technologies; Energy Conservation Programs; And Incentives and Cost Recovery for Such Programs.

2008

Colorado Public Utilities Commission Docket No. 08A-366EG: In the Matter of the Application of Public Service Company of Colorado for approval of its electric and natural gas demand-side management (DSM) plan for

calendar years 2009 and 2010 and to change its electric and gas DSM cost adjustment rates effective January 1, 2009, and for related waivers and authorizations.

Public Service Commission of Utah Docket No. 07-035-93: In the Matter of the Application of Rocky Mountain Power for Authority to Increase its Retail Electric Utility Service Rates in Utah and for Approval of its Proposed Electric Service Schedules and Electric Service Regulations, Consisting of a General Rate Increase of Approximately $161.2 Million Per Year, and for Approval of a New Large Load Surcharge.

Indiana Utility Regulatory Commission Cause No. 43374: Petition of Duke Energy Indiana, Inc. Requesting the Indiana Utility Regulatory Commission Approve an Alternative Regulatory Plan for the Offering of Energy Efficiency, Conservation, Demand Response, and Demand-Side Management.

Public Utilities Commission of Nevada Docket No. 07-12001: In the Matter of the Application of Sierra Pacific Power Company for authority to increase its general rates charged to all classes of electric customers to reflect an increase in annual revenue requirement and for relief properly related thereto.

Louisiana Public Service Commission Docket No. U-30192 *Phase II*: Ex Parte, Application of Entergy Louisiana, LLC for Approval to Repower Little Gypsy Unit 3 Electric Generating Facility and for Authority to Commence Construction and for Certain Cost Protection and Cost Recovery.

Colorado Public Utilities Commission Docket No. 07A-420E: In the Matter of the Application of Public Service Company of Colorado For Authority to Implement and Enhanced Demand Side Management Cost Adjustment Mechanism to Include Current Cost Recovery and Incentives.

2007
Louisiana Public Service Commission Docket No. U-30192: Ex Parte, Application of Entergy Louisiana, LLC for Approval to Repower Little Gypsy Unit 3 Electric Generating Facility and for Authority to Commence Construction and for Certain Cost Protection and Cost Recovery.

Public Utility Commission of Oregon Docket No. UG 173: In the Matter of PUBLIC UTILITY COMMISSION OF OREGON Staff Request to Open an Investigation into the Earnings of Cascade Natural Gas.

2006
Public Utility Commission of Oregon Docket No. UE 180/UE 181/UE 184: In the Matter of PORTLAND GENERAL ELECTRIC COMPANY Request for a General Rate Revision.

Public Utility Commission of Oregon Docket No. UE 179: In the Matter of PACIFICORP, dba PACIFIC POWER AND LIGHT COMPANY Request for a general rate increase in the company's Oregon annual revenues.

Public Utility Commission of Oregon Docket No. UM 1129 *Phase II*: Investigation Related to Electric Utility Purchases From Qualifying Facilities.

2005
Public Utility Commission of Oregon Docket No. UM 1129 *Phase I Compliance*: Investigation Related to Electric Utility Purchases From Qualifying Facilities.

Public Utility Commission of Oregon Docket No. UX 29: In the Matter of QWEST CORPORATION Petition to Exempt from Regulation Qwest's Switched Business Services.

2004
Public Utility Commission of Oregon Docket No. UM 1129 *Phase I*: Investigation Related to Electric Utility Purchases From Qualifying Facilities.

TESTIMONY BEFORE LEGISLATIVE BODIES
2012
Regarding Missouri House Bill 1488: Testimony Before the Missouri House Committee on Utilities, February 7, 2012.

2011
Regarding Missouri Senate Bills 50, 321, 359, and 406: Testimony Before the Missouri Senate Veterans' Affairs, Emerging Issues, Pensions, and Urban Affairs Committee, March 9, 2011.

AFFIDAVITS
2011
Colorado Public Utilities Commission Docket No. 11M-951E: In the Matter of the Petition of Public Service Company of Colorado Pursuant to C.R.S. § 40-6-111(1)(d) for Interim Rate Relief Effective on or before January 21, 2012.

ENERGY INDUSTRY PUBLICATIONS AND PRESENTATIONS
Panelist, Customer Panel, Virginia State Bar 29th National Regulatory Conference, Williamsburg, Virginia, May 19, 2011.

Chriss, S. (2006). "Regulatory Incentives and Natural Gas Purchasing – Lessons from the Oregon Natural Gas Procurement Study." Presented at the 19th Annual Western Conference, Center for Research in Regulated Industries Advanced Workshop in Regulation and Competition, Monterey, California, June 29, 2006.

Chriss, S. (2005). "Public Utility Commission of Oregon Natural Gas Procurement Study." Public Utility Commission of Oregon, Salem, OR. Report published in June, 2005. Presented to the Public Utility Commission of Oregon at a special public meeting on August 1, 2005.

Chriss, S. and M. Radler (2003). "Report from Houston: Conference on Energy Deregulation and Restructuring." USAEE Dialogue, Vol. 11, No. 1, March, 2003.

Chriss, S., M. Dwyer, and B. Pulliam (2002). "Impacts of Lifting the Ban on ANS Exports on West Coast Crude Oil Prices: A Reconsideration of the Evidence." Presented at the 22nd USAEE/IAEE North American Conference, Vancouver, BC, Canada, October 6-8, 2002.

Contributed to chapter on power marketing: "Power System Operations and Electricity Markets," Fred I. Denny and David E. Dismukes, authors. Published by CRC Press, June 2002.

Contributed to "Moving to the Front Lines: The Economic Impact of the Independent Power Plant Development in Louisiana," David E. Dismukes, author. Published by the Louisiana State University Center for Energy Studies, October 2001.

Dismukes, D.E., D.V. Mesyanzhinov, E.A. Downer, S. Chriss, and J.M. Burke (2001). "Alaska Natural Gas In-State Demand Study." Anchorage: Alaska Department of Natural Resources.

Wal-Mart Stores East, LP and Sam's East, Inc.
Exhibit ____ SWC-2, Calculation of Percentage of Revenues Collected Through Base Rates
Florida Public Service Commission Docket No. 130140

(1)		Total Operating Revenues, Electric Utility	$ 1,572,445,000
(2)		Total Operating Revenues, Jurisdictional	$ 528,651,000
(3)	(2) / (1)	**Percent of Jurisdictional Revenues in Base Rates**	**33.6%**

Source:
MFR Schedule C-1, page 1

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130140-EI EXHIBIT 65
PARTY Wal-Mart Stores East, LP and Sam's East, Inc. (Walmart) Direct
DESCRIPTION Steve W. Chriss (SWC-2)
DATE

Reported Authorized Returns on Equity, Electric Utility Rate Cases Completed in 2012 and 2013

State	Docket	Utility	Distribution Only	Authorized ROE	Decision Date
SC	2011-271-E	Duke Energy Carolinas LLC		10.50%	1/25/2012
NC	E-7, Sub 989	Duke Energy Carolinas LLC		10.50%	1/27/2012
MI	16801	Indiana-Michigan Power Co.		10.20%	2/15/2012
OR	UE 233	Idaho Power Co.		9.90%	2/23/2012
FL	110138	Gulf Power Co.		10.25%	2/27/2012
ND	PU-10-657	Northern States Power Co.		10.40%	2/29/2012
MN	10-971	Northern States Power Co.		10.37%	3/29/2012
HI	2009-0164	Hawaii Electric Light Co.		10.00%	4/4/2012
CO	11AL-947E	Public Service Company of Colorado		10.00%	4/26/2012
HI	2009-0163	Maui Electric Company Ltd		10.00%	5/2/2012
WA	UE-111048	Puget Sound Energy Inc.		9.80%	5/7/2012
AZ	E-01345A-11-0224	Arizona Public Service Co.		10.00%	5/15/2012
IL	11-0721	Commonwealth Edison Co.	Yes	10.05%	5/29/2012
MI	16794	Consumers Energy Co.		10.30%	6/7/2012
NY	11-E-0408	Orange & Rockland Utilities Inc.	Yes	9.40%	6/14/2012
WI	6680-UR-118	Wisconsin Power and Light Co.		10.40%	6/15/2012
WY	20003-114-ER-11	Cheyenne Light Fuel Power Co.		9.60%	6/18/2012
SD	EL11-019	Northern States Power Co.		9.25%	6/19/2012
MI	16830	Wisconsin Electric Power Co.		10.10%	6/26/2012
HI	2009-0080	Hawaiian Electric Co.		10.00%	6/29/2012
OK	PUD 201100087	Oklahoma Gas and Electric Co.		10.20%	7/9/2012
WY	20000-405-ER-11	Rocky Mountain Power		9.80%	7/16/2012
MD	9285	Delmarva Power & Light Co.	Yes	9.81%	7/20/2012
MD	9286	Potomac Edison Power Co.	Yes	9.31%	7/20/2012
TX	39896	Entergy Texas Inc.		9.80%	9/13/2012
IL	12-0001	Ameren Illinois	Yes	10.05%	9/19/2012
UT	11-035-200	Rocky Mountain Power		9.80%	9/19/2012
DC	1087	Potomac Edison Power Co.	Yes	9.50%	9/26/2012
NJ	ER-11080469	Atlantic City Electric Co.	Yes	9.75%	10/23/2012
WI	6690-UR-121	Wisconsin Public Service Corp.		10.30%	10/24/2012
WI	3270-UR-118	Madison Gas and Electric Co.		10.30%	11/9/2012
WI	05-UR-106	Wisconsin Electric Power Co.		10.40%	11/28/2012
CA	A12-02-014	California Pacific Electric Co.		9.88%	11/29/2012
DE	D-11-528	Delmarva Power & Light Co.	Yes	9.75%	11/29/2012
IL	12-0293	Ameren Illinois	Yes	9.71%	12/5/2012
PA	E-2012-2290597	PPL Electric Utilities Corp	Yes	10.40%	12/5/2012
MO	ER-2012-0166	Union Electric Co.		9.80%	12/12/2012
FL	120015	Florida Power & Light		10.50%	12/13/2012
KS	12-KCPE-764-RTS	Kansas City Power & Light		9.50%	12/13/2012
WI	4220-UR-118	Northern States Power Co.		10.40%	12/14/2012
IL	12-0321	Commonwealth Edison Co.	Yes	9.71%	12/19/2012
SC	2012-218-E	South Carolina Electric & Gas		10.25%	12/19/2012
CA	A12-04-018	Pacific Gas & Electric		10.40%	12/20/2012
CA	A12-04-016	San Diego Gas & Electric		10.30%	12/20/2012
CA	A12-04-015	Southern California Edison		10.45%	12/20/2012
KY	2012-00221	Kentucky Utilities		10.25%	12/20/2012
KY	2012-00222	Louisville Gas & Electric		10.25%	12/20/2012
OR	UE 246	PacifiCorp		9.80%	12/20/2012
RI	4323	Narragansett Electric Co.	Yes	9.50%	12/20/2012
NC	E-22, Sub 479	Virginia Electric & Power Co.		10.20%	12/21/2012
WA	UE-120436	Avista Corp.		9.80%	12/26/2012
MO	ER-2012-0174	Kansas City Power & Light		9.70%	1/9/2013
MO	ER-2012-0175	KCP&L Greater Missouri Op Co.		9.70%	1/9/2013
IN	44075	Indiana-Michigan Power Co.		10.20%	2/13/2013
MD	9299	Baltimore Gas and Electric Co.	Yes	9.75%	2/22/2013

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130140-EI EXHIBIT 66
PARTY Wal-Mart Stores East, LP and Sam's East, Inc. (Walmart) Direct
DESCRIPTION Steve W. Chriss (SWC-3)
DATE

Reported Authorized Returns on Equity, Electric Utility Rate Cases Completed in 2012 and 2013

State	Docket	Utility	Distribution Only	Authorized ROE	Decision Date
LA	U-32220	Southwestern Electric Power Co.		10.00%	2/27/2013
NY	12-E-0201	Niagara Mohawk Power Corp.	Yes	9.30%	3/14/2013
ID	AVU-E-12-08	Avista Corp.		9.80%	3/27/2013
OH	12-1682-EL-AIR	Duke Energy Ohio Inc.	Yes	9.84%	5/1/2013
MI	U-17087	Consumers Energy Co.		10.30%	5/15/2013
NC	E-2, Sub 1023	Duke Energy Progress Inc.		10.20%	5/30/2013
HI	2011-0092	Maui Electric Company Ltd		9.00%	5/31/2013
AZ	E-01933A-12-0291	Tucson Electric Power Co.		10.00%	6/11/2013
NJ	ER-12121071	Atlantic City Electric Co.	Yes	9.75%	6/21/2013
WA	UE-130137	Puget Sound Energy Inc.		9.80%	6/25/2013
MD	9311	Potomac Edison Power Co.	Yes	9.36%	7/12/2013
MN	E-002/GR-12-961	Northern States Power Co.		9.83%	8/8/2013
CT	13-01-19	United Illuminating	Yes	9.15%	8/14/2013
SC	2013-59-E	Duke Energy Carolinas LLC		10.20%	9/11/2013
FL	130040-EI	Tampa Electric Co.		10.25%	9/11/2013
NC	E-7, Sub 1026	Duke Energy Carolinas LLC		10.20%	9/24/2013
TX	40443	Southwestern Electric Power Co.		9.65%	10/3/2013

# of Decisions	**72**
Average (All Utilities)	**9.96%**
Average (Excluding Distribution Only)	**10.05%**
Median	**10.00%**
Minimum	**9.00%**
Maximum	**10.50%**

Source: SNL Financial LC, October 10, 2013

Gulf Power Company

Rate of Return
Adjusted Capital Structure
2014 Test Year

Line	Description	Amount (000) (1)	Specific Adjustments (2)	Pro Rata Adjustments (3)	System Adjusted (4)	Allocation (5)	Juris Adjusted Amount (6)	Weight (7)	Cost (8)	Weighted Cost (9)
1	Long-Term Debt	$ 1,281,856	$ (103,347)	$ (600,313)	$ 578,196	0.9809660	$ 567,191	30.11%	4.96%	1.49%
2	Short-Term Debt	$ 51,663	$ (4,154)	$ (24,200)	$ 23,309	0.9809660	$ 22,865	1.21%	0.82%	0.01%
3	Preferrence Stock	$ 147,998.0	$ (11,941)	$ (69,305)	$ 66,752	0.9809660	$ 65,481	3.48%	6.00%	0.21%
4	Common Equity	$ 1,332,898	$ (102,440)	$ (626,775)	$ 603,683	0.9809660	$ 592,193	31.43%	**9.45%**	2.97%
5	Customer Deposits	$ 35,350	$ -	$ -	$ 35,350	1.0000000	$ 35,350	1.88%	2.30%	0.04%
6	Deferred Income Tax	$ 707,553	$ (53,944)	$ -	$ 653,609	0.9809660	$ 641,168	34.03%	0.00%	0.00%
7	FASB 109 Deferred Taxes	$ (47,899)	$ 3,652	$ -	$ (44,247)	0.9809660	$ (43,405)	-2.30%	0.00%	0.00%
8	Investment Tax Credit	$ 3,492	$ (375)	$ -	$ 3,117	0.9809660	$ 3,058	0.16%	7.07%	0.01%
9	**Total**	**$ 3,512,911**	**$ (272,549)**	**$ (1,320,593)**	**$ 1,919,769**		**$ 1,883,901**	100.00%		4.74%

Investor Capital Structure

Line	Description	Investor Capital Amount (000)* (1)	Investor Capital Weight (2)	Pro-Rata Allocation (3)
10	Long-Term Debt	$ 1,178,509	45.46%	$ (600,313)
11	Short-Term Debt	$ 47,509	1.83%	$ (24,200)
12	Preferrence Stock	$ 136,057	5.25%	$ (69,305)
13	Common Equity	$ 1,230,458	47.46%	$ (626,775)
14	**Total**	**$ 2,592,533**	**100.00%**	$ (1,320,593)

Source:
MFR Schedule D-1a.
* Sum of Columns 1 and 2, Lines 1 through 4.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130140-EI EXHIBIT 67
PARTY Federal Executive Agencies (FEA) Direct
DESCRIPTION Michael P. Gorman (MPG-1)
DATE

Gulf Power Company

Proxy Group

Line	Company	Credit Ratings[1] S&P (1)	Credit Ratings[1] Moody's (2)	Common Equity Ratios SNL[1] (3)	Common Equity Ratios Value Line[2] (4)	S&P Business Risk Score[3] (5)
1	ALLETE, Inc.	BBB+	Baa1	54.1%	56.3%	Strong
2	Alliant Energy Corporation	A-	Baa1	46.1%	48.4%	Excellent
3	American Electric Power Company, Inc.	BBB	Baa2	44.3%	49.4%	Excellent
4	Black Hills Corporation	BBB	Baa3	48.3%	56.8%	Excellent
5	CenterPoint Energy, Inc.	A-	Baa2	30.5%	34.0%	Excellent
6	CMS Energy Corporation	BBB	Baa3	29.7%	31.6%	Excellent
7	Dominion Resources, Inc.	A-	Baa2	32.6%	38.2%	Excellent
8	DTE Energy Company	BBB+	Baa1	47.6%	51.2%	Strong
9	Duke Energy Corporation	BBB+	Baa2	50.1%	52.9%	Excellent
10	Great Plains Energy Inc.	BBB	Baa3	46.9%	54.4%	Excellent
11	Hawaiian Electric Industries, Inc.	BBB-	Baa2	50.0%	53.1%	Strong
12	Integrys Energy Group, Inc.	A-	Baa1	52.1%	60.4%	Excellent
13	NextEra Energy, Inc.	A-	Baa1	37.0%	40.9%	Strong
14	Northeast Utilities	A-	Baa2	49.7%	55.4%	Excellent
15	NorthWestern Corporation	BBB	Baa1	43.5%	46.2%	Excellent
16	OGE Energy Corp.	A-	Baa1	43.6%	49.3%	Excellent
17	Otter Tail Corporation	BBB	Baa3	54.4%	54.4%	Strong
18	Pepco Holdings, Inc.	BBB+	Baa3	44.4%	52.7%	Excellent
19	Pinnacle West Capital Corporation	BBB+	Baa2	52.9%	55.4%	Excellent
20	PNM Resources, Inc.	BBB	Ba1	45.5%	48.7%	Excellent
21	Portland General Electric Company	BBB	Baa1	51.1%	52.9%	Excellent
22	SCANA Corporation	BBB+	Baa3	42.0%	45.6%	Excellent
23	Sempra Energy	BBB+	Baa1	43.5%	46.7%	Strong
24	Southern Company	A	Baa1	43.8%	47.3%	Excellent
25	Vectren Corporation	A-	N/A	44.0%	49.6%	Excellent
26	Westar Energy, Inc.	BBB	Baa2	45.4%	48.8%	Excellent
27	Wisconsin Energy Corporation	A-	A3	43.9%	48.0%	Excellent
28	Xcel Energy Inc.	A-	Baa1	44.6%	46.7%	Excellent
29	**Average**	**BBB+**	**Baa2**	**45.1%**	**49.1%**	**Excellent**
30	Gulf Power Company	**A[4]**	**A3[4]**	**47.5%[5]**		Excellent

Sources:
[1] SNL Financial, Downloaded on September 24.
[2] *The Value Line Investment Survey,* August 2, August 23, and September 20, 2013.
[3] *S&P RatingsDirect:* "U.S. Regulated Utilities, Strongest To Weakest,"July 30, 2013.
[4] Teel Direct at 18.
[5] Teel Direct at 23.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130140-EI EXHIBIT 68
PARTY Federal Executive Agencies (FEA) Direct
DESCRIPTION Michael P. Gorman (MPG-1)
DATE

Gulf Power Company

Consensus Analysts' Growth Rates

Line	Company	Zacks Estimated Growth %[1] (1)	Zacks Number of Estimates (2)	SNL Estimated Growth %[2] (3)	SNL Number of Estimates (4)	Reuters Estimated Growth %[3] (5)	Reuters Number of Estimates (6)	Average of Growth Rates (7)
1	ALLETE, Inc.	6.00%	N/A	6.00%	1	6.00%	1	6.00%
2	Alliant Energy Corporation	5.27%	N/A	4.40%	2	5.40%	2	5.02%
3	American Electric Power Company, Inc.	3.87%	N/A	4.00%	5	4.06%	7	3.98%
4	Black Hills Corporation	4.00%	N/A	5.00%	2	4.00%	1	4.33%
5	CenterPoint Energy, Inc.	5.30%	N/A	4.70%	3	4.50%	5	4.83%
6	CMS Energy Corporation	5.85%	N/A	5.80%	3	5.87%	4	5.84%
7	Dominion Resources, Inc.	5.82%	N/A	6.70%	2	6.66%	4	6.39%
8	DTE Energy Company	4.64%	N/A	4.50%	2	4.60%	3	4.58%
9	Duke Energy Corporation	3.69%	N/A	3.60%	3	3.85%	7	3.71%
10	Great Plains Energy Inc.	6.49%	N/A	6.20%	3	6.43%	3	6.37%
11	Hawaiian Electric Industries, Inc.	2.40%	N/A	2.40%	1	3.70%	2	2.83%
12	Integrys Energy Group, Inc.	5.00%	N/A	5.50%	2	5.00%	1	5.17%
13	NextEra Energy, Inc.	6.19%	N/A	6.30%	3	6.10%	5	6.20%
14	Northeast Utilities	7.85%	N/A	8.10%	3	7.19%	6	7.71%
15	NorthWestern Corporation	4.50%	N/A	6.00%	3	N/A	N/A	5.25%
16	OGE Energy Corp.	5.53%	N/A	5.40%	3	4.55%	2	5.16%
17	Otter Tail Corporation	N/A	N/A	N/A	N/A	N/A	N/A	N/A
18	Pepco Holdings, Inc.	5.02%	N/A	4.80%	5	3.82%	5	4.55%
19	Pinnacle West Capital Corporation	4.59%	N/A	4.60%	5	4.72%	4	4.64%
20	PNM Resources, Inc.	7.77%	N/A	7.80%	3	6.43%	3	7.33%
21	Portland General Electric Company	5.90%	N/A	5.90%	2	6.22%	4	6.01%
22	SCANA Corporation	4.70%	N/A	4.30%	2	4.83%	3	4.61%
23	Sempra Energy	4.95%	N/A	2.90%	1	2.90%	1	3.58%
24	Southern Company	4.44%	N/A	4.10%	4	4.54%	6	4.36%
25	Vectren Corporation	5.00%	N/A	N/A	N/A	N/A	N/A	5.00%
26	Westar Energy, Inc.	3.37%	N/A	2.50%	3	2.50%	3	2.79%
27	Wisconsin Energy Corporation	5.38%	N/A	5.30%	3	5.21%	3	5.30%
28	Xcel Energy Inc.	4.34%	N/A	4.20%	4	5.45%	5	4.66%
29	**Average**	**5.11%**	**N/A**	**5.04%**	**3**	**4.98%**	**4**	**5.04%**

Sources:
[1] Zacks Elite, http://www.zackselite.com/, downloaded on September 24, 2013.
[2] SNL Interactive, http://www.snl.com/, downloaded on September 24, 2013.
[3] Reuters, http://www.reuters.com/, downloaded on September 24, 2013.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130140-EI EXHIBIT 69
PARTY Federal Executive Agencies (FEA) Direct
DESCRIPTION Michael P. Gorman (MPG-3)
DATE

Gulf Power Company

Constant Growth DCF Model
(Consensus Analysts' Growth Rates)

Line	Company	13-Week AVG Stock Price[1] (1)	Analysts' Growth[2] (2)	Annualized Dividend[3] (3)	Adjusted Yield (4)	Constant Growth DCF (5)
1	ALLETE, Inc.	$49.75	6.00%	$1.90	4.05%	10.05%
2	Alliant Energy Corporation	$50.99	5.02%	$1.88	3.87%	8.90%
3	American Electric Power Company, Inc.	$44.48	3.98%	$1.96	4.58%	8.56%
4	Black Hills Corporation	$50.38	4.33%	$1.52	3.15%	7.48%
5	CenterPoint Energy, Inc.	$23.76	4.83%	$0.83	3.66%	8.50%
6	CMS Energy Corporation	$27.19	5.84%	$1.02	3.97%	9.81%
7	Dominion Resources, Inc.	$58.69	6.39%	$2.25	4.08%	10.47%
8	DTE Energy Company	$67.92	4.58%	$2.62	4.03%	8.61%
9	Duke Energy Corporation	$68.12	3.71%	$3.12	4.75%	8.46%
10	Great Plains Energy Inc.	$22.99	6.37%	$0.87	4.03%	10.40%
11	Hawaiian Electric Industries, Inc.	$25.66	2.83%	$1.24	4.97%	7.80%
12	Integrys Energy Group, Inc.	$58.74	5.17%	$2.72	4.87%	10.04%
13	NextEra Energy, Inc.	$82.44	6.20%	$2.64	3.40%	9.60%
14	Northeast Utilities	$42.25	7.71%	$1.47	3.75%	11.46%
15	NorthWestern Corporation	$41.31	5.25%	$1.52	3.87%	9.12%
16	OGE Energy Corp.	$35.88	5.16%	$0.84	2.45%	7.61%
17	Otter Tail Corporation	$28.67	N/A	$1.19	N/A	N/A
18	Pepco Holdings, Inc.	$19.56	4.55%	$1.08	5.77%	10.32%
19	Pinnacle West Capital Corporation	$55.98	4.64%	$2.18	4.07%	8.71%
20	PNM Resources, Inc.	$22.69	7.33%	$0.66	3.12%	10.46%
21	Portland General Electric Company	$30.07	6.01%	$1.10	3.88%	9.88%
22	SCANA Corporation	$49.41	4.61%	$2.03	4.30%	8.91%
23	Sempra Energy	$84.27	3.58%	$2.52	3.10%	6.68%
24	Southern Company	$43.21	4.36%	$2.03	4.90%	9.26%
25	Vectren Corporation	$34.39	5.00%	$1.42	4.34%	9.34%
26	Westar Energy, Inc.	$31.97	2.79%	$1.36	4.37%	7.16%
27	Wisconsin Energy Corporation	$41.57	5.30%	$1.53	3.88%	9.17%
28	Xcel Energy Inc.	$28.57	4.66%	$1.12	4.10%	8.77%
29	**Average**	**$43.60**	**5.04%**	**$1.66**	**4.05%**	**9.09%**
30	**Median**					**9.12%**

Sources:
[1] SNL Financial, Downloaded on September 25, 2013
[2] Exhibit MPG-3.
[3] *The Value Line Investment Survey,* August 2, August 23, and September 20, 2013.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130140-EI EXHIBIT 70
PARTY Federal Executive Agencies (FEA) Direct
DESCRIPTION Michael P. Gorman (MPG-4)
DATE

Gulf Power Company

Payout Ratios

Line	Company	Dividends Per Share 2012 (1)	Dividends Per Share Projected (2)	Earnings Per Share 2012 (3)	Earnings Per Share Projected (4)	Payout Ratio 2012 (5)	Payout Ratio Projected (6)
1	ALLETE, Inc.	$1.84	$2.20	$2.58	$3.75	71.32%	58.67%
2	Alliant Energy Corporation	$1.80	$2.20	$3.05	$4.00	59.02%	55.00%
3	American Electric Power Company, Inc.	$1.88	$2.30	$2.98	$3.75	63.09%	61.33%
4	Black Hills Corporation	$1.48	$1.70	$1.97	$3.00	75.13%	56.67%
5	CenterPoint Energy, Inc.	$0.81	$1.00	$1.35	$1.75	60.00%	57.14%
6	CMS Energy Corporation	$0.96	$1.30	$1.53	$2.00	62.75%	65.00%
7	Dominion Resources, Inc.	$2.11	$2.70	$2.75	$3.75	76.73%	72.00%
8	DTE Energy Company	$2.42	$3.15	$3.88	$4.75	62.37%	66.32%
9	Duke Energy Corporation	$3.03	$3.35	$3.71	$5.00	81.67%	67.00%
10	Great Plains Energy Inc.	$0.86	$1.20	$1.35	$2.00	63.70%	60.00%
11	Hawaiian Electric Industries, Inc.	$1.24	$1.30	$1.68	$1.75	73.81%	74.29%
12	Integrys Energy Group, Inc.	$2.72	$2.90	$3.67	$4.25	74.11%	68.24%
13	NextEra Energy, Inc.	$2.40	$3.60	$4.56	$6.50	52.63%	55.38%
14	Northeast Utilities	$1.32	$1.80	$1.89	$3.25	69.84%	55.38%
15	NorthWestern Corporation	$1.48	$1.80	$2.26	$3.00	65.49%	60.00%
16	OGE Energy Corp.	$0.80	$1.25	$1.79	$2.25	44.69%	55.56%
17	Otter Tail Corporation	$1.19	$1.30	$1.05	$2.00	113.33%	65.00%
18	Pepco Holdings, Inc.	$1.08	$1.16	$1.24	$1.70	87.10%	68.24%
19	Pinnacle West Capital Corporation	$2.67	$2.60	$3.50	$4.25	76.29%	61.18%
20	PNM Resources, Inc.	$0.58	$1.08	$1.31	$2.15	44.27%	50.23%
21	Portland General Electric Company	$1.08	$1.25	$1.87	$2.25	57.75%	55.56%
22	SCANA Corporation	$1.98	$2.25	$3.15	$4.00	62.86%	56.25%
23	Sempra Energy	$2.40	$3.00	$4.35	$5.50	55.17%	54.55%
24	Southern Company	$1.94	$2.30	$2.67	$3.25	72.66%	70.77%
25	Vectren Corporation	$1.41	$1.60	$1.94	$2.70	72.68%	59.26%
26	Westar Energy, Inc.	$1.32	$1.52	$2.15	$2.70	61.40%	56.30%
27	Wisconsin Energy Corporation	$1.20	$2.00	$2.35	$3.00	51.06%	66.67%
28	Xcel Energy Inc.	$1.07	$1.35	$1.85	$2.25	57.84%	60.00%
29	**Average**	**$1.61**	**$1.97**	**$2.44**	**$3.23**	**66.74%**	**61.14%**

Source:
The Value Line Investment Survey, August 2, August 23, and September 20, 2013.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130140-EI EXHIBIT 71
PARTY Federal Executive Agencies (FEA) Direct
DESCRIPTION Michael P. Gorman (MPG-5)
DATE

Gulf Power Company

Sustainable Growth Rate

Line	Company	3 to 5 Year Projections: Dividends Per Share (1)	Earnings Per Share (2)	Book Value Per Share (3)	Book Value Growth (4)	ROE (5)	Adjustment Factor (6)	Adjusted ROE (7)	Payout Ratio (8)	Retention Rate (9)	Internal Growth Rate (10)	Sustainable Growth Rate (11)
1	ALLETE, Inc.	$2.20	$3.75	$36.50	3.67%	10.27%	1.02	10.46%	58.67%	41.33%	4.32%	6.17%
2	Alliant Energy Corporation	$2.20	$4.00	$34.50	4.08%	11.59%	1.02	11.83%	55.00%	45.00%	5.32%	6.04%
3	American Electric Power Company, Inc.	$2.30	$3.75	$38.00	3.91%	9.87%	1.02	10.06%	61.33%	38.67%	3.89%	4.22%
4	Black Hills Corporation	$1.70	$3.00	$33.25	3.59%	9.02%	1.02	9.18%	56.67%	43.33%	3.98%	4.52%
5	CenterPoint Energy, Inc.	$1.00	$1.75	$12.25	4.02%	14.29%	1.02	14.57%	57.14%	42.86%	6.24%	6.60%
6	CMS Energy Corporation	$1.30	$2.00	$16.25	6.09%	12.31%	1.03	12.67%	65.00%	35.00%	4.44%	5.36%
7	Dominion Resources, Inc.	$2.70	$3.75	$25.50	6.80%	14.71%	1.03	15.19%	72.00%	28.00%	4.25%	7.51%
8	DTE Energy Company	$3.15	$4.75	$53.00	4.38%	8.96%	1.02	9.15%	66.32%	33.68%	3.08%	4.24%
9	Duke Energy Corporation	$3.35	$5.00	$63.75	1.89%	7.84%	1.01	7.92%	67.00%	33.00%	2.61%	2.64%
10	Great Plains Energy Inc.	$1.20	$2.00	$25.00	2.82%	8.00%	1.01	8.11%	60.00%	40.00%	3.24%	3.26%
11	Hawaiian Electric Industries, Inc.	$1.30	$1.75	$20.75	4.97%	8.43%	1.02	8.64%	74.29%	25.71%	2.22%	5.05%
12	Integrys Energy Group, Inc.	$2.90	$4.25	$50.50	5.39%	8.42%	1.03	8.64%	68.24%	31.76%	2.74%	3.46%
13	NextEra Energy, Inc.	$3.60	$6.50	$52.75	6.84%	12.32%	1.03	12.73%	55.38%	44.62%	5.68%	7.35%
14	Northeast Utilities	$1.80	$3.25	$34.75	3.39%	9.35%	1.02	9.51%	55.38%	44.62%	4.24%	4.38%
15	NorthWestern Corporation	$1.80	$3.00	$31.25	4.49%	9.60%	1.02	9.81%	60.00%	40.00%	3.92%	4.53%
16	OGE Energy Corp.	$1.25	$2.25	$19.25	6.58%	11.69%	1.03	12.06%	55.56%	44.44%	5.36%	6.21%
17	Otter Tail Corporation	$1.30	$2.00	$18.00	4.52%	11.11%	1.02	11.36%	65.00%	35.00%	3.97%	5.98%
18	Pepco Holdings, Inc.	$1.16	$1.70	$21.50	2.15%	7.91%	1.01	7.99%	68.24%	31.76%	2.54%	2.56%
19	Pinnacle West Capital Corporation	$2.60	$4.25	$43.25	3.62%	9.83%	1.02	10.00%	61.18%	38.82%	3.88%	4.40%
20	PNM Resources, Inc.	$1.08	$2.15	$23.60	3.31%	9.11%	1.02	9.26%	50.23%	49.77%	4.61%	4.62%
21	Portland General Electric Company	$1.25	$2.25	$26.75	3.18%	8.41%	1.02	8.54%	55.56%	44.44%	3.80%	4.88%
22	SCANA Corporation	$2.25	$4.00	$40.75	5.30%	9.82%	1.03	10.07%	56.25%	43.75%	4.41%	6.64%
23	Sempra Energy	$3.00	$5.50	$52.00	4.16%	10.58%	1.02	10.79%	54.55%	45.45%	4.91%	5.52%
24	Southern Company	$2.30	$3.25	$25.75	4.07%	12.62%	1.02	12.87%	70.77%	29.23%	3.76%	5.23%
25	Vectren Corporation	$1.60	$2.70	$23.00	4.37%	11.74%	1.02	11.99%	59.26%	40.74%	4.88%	5.86%
26	Westar Energy, Inc.	$1.52	$2.70	$29.65	5.31%	9.11%	1.03	9.34%	56.30%	43.70%	4.08%	4.60%
27	Wisconsin Energy Corporation	$2.00	$3.00	$21.25	3.32%	14.12%	1.02	14.35%	66.67%	33.33%	4.78%	4.78%
28	Xcel Energy Inc.	$1.35	$2.25	$23.00	4.80%	9.78%	1.02	10.01%	60.00%	40.00%	4.00%	4.62%
29	**Average**	**$1.97**	**$3.23**	**$31.99**	**4.32%**	**10.39%**	**1.02**	**10.61%**	**61.14%**	**38.86%**	**4.11%**	**5.04%**

Sources and Notes:

Cols. (1), (2) and (3): *The Value Line Investment Survey*, August 2, August 23, and September 20, 2013.
Col. (4): [Col. (3) / Page 2 Col. (2)] ^ (1/5) - 1.
Col. (5): Col. (2) / Col. (3).
Col. (6): [2 * (1 + Col. (4))] / (2 + Col. (4)).
Col. (7): Col. (6) * Col. (5).
Col. (8): Col. (1) / Col. (2).
Col. (9): 1 - Col. (8).
Col. (10): Col. (9) * Col. (7).
Col. (11): Col. (10) + Page 2 Col. (9).

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130140-EI EXHIBIT 72
PARTY Federal Executive Agencies (FEA) Direct
DESCRIPTION Michael P. Gorman (MPG-6)
DATE

Gulf Power Company

Sustainable Growth Rate

Line	Company	13-Week Average Stock Price[1] (1)	2012 Book Value Per Share[2] (2)	Market to Book Ratio (3)	Common Shares Outstanding (in Millions)[2] 2012 (4)	Common Shares Outstanding (in Millions)[2] 3-5 Years (5)	Growth (6)	S Factor[3] (7)	V Factor[4] (8)	S * V (9)
1	ALLETE, Inc.	$49.75	$30.48	1.63	39.40	45.50	2.92%	4.77%	38.74%	1.85%
2	Alliant Energy Corporation	$50.99	$28.25	1.81	110.99	116.00	0.89%	1.60%	44.60%	0.71%
3	American Electric Power Company, Inc.	$44.48	$31.37	1.42	485.67	505.00	0.78%	1.11%	29.48%	0.33%
4	Black Hills Corporation	$50.38	$27.88	1.81	44.21	45.70	0.67%	1.20%	44.66%	0.54%
5	CenterPoint Energy, Inc.	$23.76	$10.06	2.36	427.44	433.00	0.26%	0.61%	57.65%	0.35%
6	CMS Energy Corporation	$27.19	$12.09	2.25	264.10	274.00	0.74%	1.66%	55.54%	0.92%
7	Dominion Resources, Inc.	$58.69	$18.35	3.20	576.00	620.00	1.48%	4.74%	68.73%	3.26%
8	DTE Energy Company	$67.92	$42.78	1.59	172.35	190.00	1.97%	3.13%	37.02%	1.16%
9	Duke Energy Corporation	$68.12	$58.04	1.17	704.00	710.00	0.17%	0.20%	14.79%	0.03%
10	Great Plains Energy Inc.	$22.99	$21.75	1.06	153.53	156.00	0.32%	0.34%	5.39%	0.02%
11	Hawaiian Electric Industries, Inc.	$25.66	$16.28	1.58	97.93	124.50	4.92%	7.75%	36.55%	2.83%
12	Integrys Energy Group, Inc.	$58.74	$38.84	1.51	77.90	83.50	1.40%	2.11%	33.88%	0.72%
13	NextEra Energy, Inc.	$82.44	$37.90	2.18	424.00	455.00	1.42%	3.09%	54.02%	1.67%
14	Northeast Utilities	$42.25	$29.41	1.44	314.05	319.00	0.31%	0.45%	30.39%	0.14%
15	NorthWestern Corporation	$41.31	$25.09	1.65	37.22	39.00	0.94%	1.55%	39.26%	0.61%
16	OGE Energy Corp.	$35.88	$14.00	2.56	197.60	203.00	0.54%	1.39%	60.98%	0.84%
17	Otter Tail Corporation	$28.67	$14.43	1.99	36.17	40.00	2.03%	4.04%	49.66%	2.01%
18	Pepco Holdings, Inc.	$19.56	$19.33	1.01	230.02	255.00	2.08%	2.11%	1.17%	0.02%
19	Pinnacle West Capital Corporation	$55.98	$36.20	1.55	109.74	115.00	0.94%	1.45%	35.33%	0.51%
20	PNM Resources, Inc.	$22.69	$20.05	1.13	79.65	80.00	0.09%	0.10%	11.62%	0.01%
21	Portland General Electric Company	$30.07	$22.87	1.31	75.56	89.50	3.44%	4.53%	23.95%	1.08%
22	SCANA Corporation	$49.41	$31.47	1.57	132.00	160.00	3.92%	6.16%	36.31%	2.24%
23	Sempra Energy	$84.27	$42.42	1.99	242.37	250.00	0.62%	1.24%	49.66%	0.61%
24	Southern Company	$43.21	$21.09	2.05	867.77	930.00	1.39%	2.86%	51.19%	1.46%
25	Vectren Corporation	$34.39	$18.57	1.85	82.20	87.00	1.14%	2.11%	46.00%	0.97%
26	Westar Energy, Inc.	$31.97	$22.89	1.40	126.50	135.00	1.31%	1.83%	28.40%	0.52%
27	Wisconsin Energy Corporation	$41.57	$18.05	2.30	229.04	227.50	-0.13%	-0.31%	56.58%	-0.18%
28	Xcel Energy Inc.	$28.57	$18.19	1.57	487.96	515.00	1.08%	1.70%	36.34%	0.62%
29	**Average**	**$43.60**	**$26.00**	**1.75**	**243.76**	**257.26**	**1.40%**	**2.36%**	**38.50%**	**0.96%**

Sources and Notes:

[1] SNL Financial, Downloaded on September 25, 2013

[2] *The Value Line Investment Survey*, August 2, August 23, and September 20, 2013.

[3] Expected Growth in the Number of Shares, Column (3) * Column (6).

[4] Expected Profit of Stock Investment, [1 - 1 / Column (3)].

Gulf Power Company

Constant Growth DCF Model
(Sustainable Growth Rate)

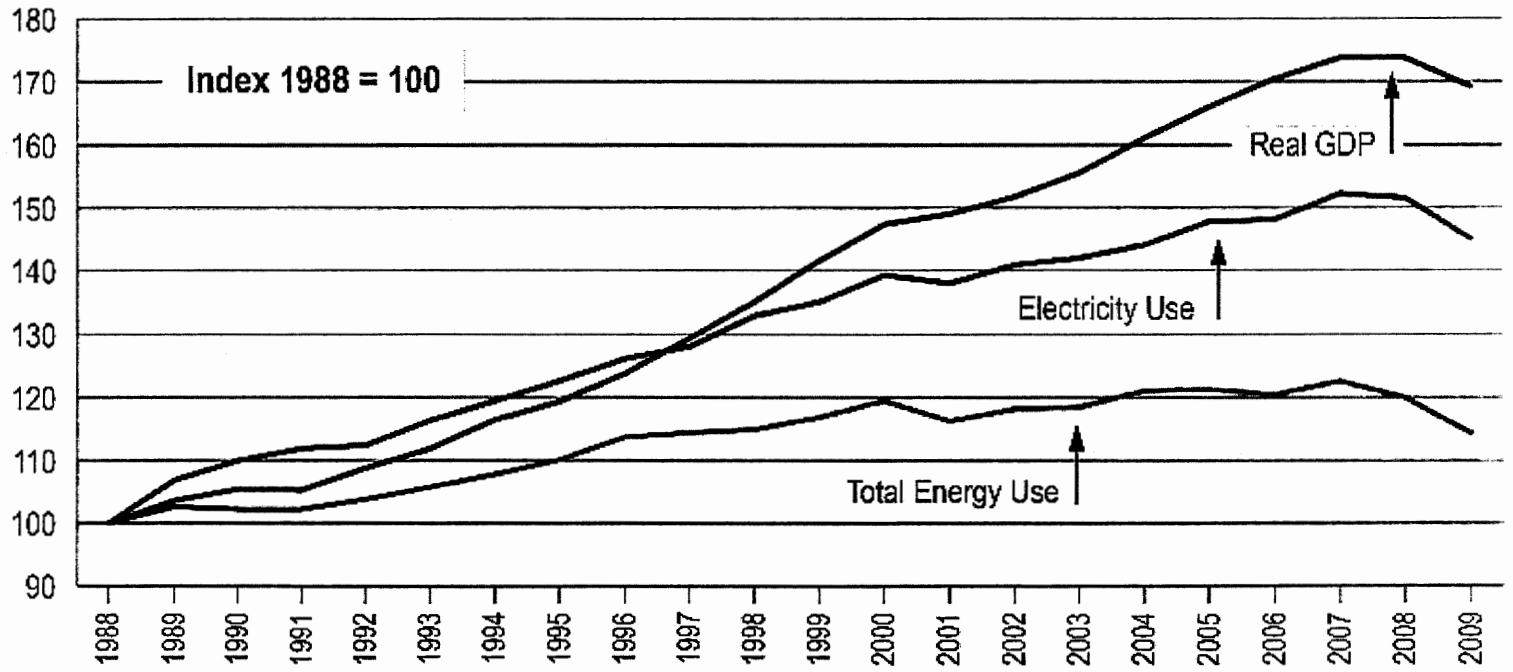
Line	Company	13-Week AVG Stock Price[1] (1)	Sustainable Growth[2] (2)	Annualized Dividend[3] (3)	Adjusted Yield (4)	Constant Growth DCF (5)
1	ALLETE, Inc.	$49.75	6.17%	$1.90	4.05%	10.22%
2	Alliant Energy Corporation	$50.99	6.04%	$1.88	3.91%	9.95%
3	American Electric Power Company, Inc.	$44.48	4.22%	$1.96	4.59%	8.81%
4	Black Hills Corporation	$50.38	4.52%	$1.52	3.15%	7.67%
5	CenterPoint Energy, Inc.	$23.76	6.60%	$0.83	3.72%	10.32%
6	CMS Energy Corporation	$27.19	5.36%	$1.02	3.95%	9.31%
7	Dominion Resources, Inc.	$58.69	7.51%	$2.25	4.12%	11.64%
8	DTE Energy Company	$67.92	4.24%	$2.62	4.02%	8.26%
9	Duke Energy Corporation	$68.12	2.64%	$3.12	4.70%	7.34%
10	Great Plains Energy Inc.	$22.99	3.26%	$0.87	3.91%	7.17%
11	Hawaiian Electric Industries, Inc.	$25.66	5.05%	$1.24	5.08%	10.13%
12	Integrys Energy Group, Inc.	$58.74	3.46%	$2.72	4.79%	8.25%
13	NextEra Energy, Inc.	$82.44	7.35%	$2.64	3.44%	10.79%
14	Northeast Utilities	$42.25	4.38%	$1.47	3.63%	8.01%
15	NorthWestern Corporation	$41.31	4.53%	$1.52	3.85%	8.38%
16	OGE Energy Corp.	$35.88	6.21%	$0.84	2.47%	8.68%
17	Otter Tail Corporation	$28.67	5.98%	$1.19	4.41%	10.39%
18	Pepco Holdings, Inc.	$19.56	2.56%	$1.08	5.66%	8.23%
19	Pinnacle West Capital Corporation	$55.98	4.40%	$2.18	4.07%	8.46%
20	PNM Resources, Inc.	$22.69	4.62%	$0.66	3.04%	7.66%
21	Portland General Electric Company	$30.07	4.88%	$1.10	3.84%	8.72%
22	SCANA Corporation	$49.41	6.64%	$2.03	4.38%	11.02%
23	Sempra Energy	$84.27	5.52%	$2.52	3.16%	8.67%
24	Southern Company	$43.21	5.23%	$2.03	4.94%	10.17%
25	Vectren Corporation	$34.39	5.86%	$1.42	4.37%	10.23%
26	Westar Energy, Inc.	$31.97	4.60%	$1.36	4.45%	9.05%
27	Wisconsin Energy Corporation	$41.57	4.78%	$1.53	3.86%	8.64%
28	Xcel Energy Inc.	$28.57	4.62%	$1.12	4.10%	8.73%
29	**Average**	**$43.60**	**5.04%**	**$1.66**	**4.06%**	**9.10%**
30	**Median**					**8.72%**

Sources:
[1] SNL Financial, Downloaded on September 25, 2013
[2] Exhibit MPG-6, page 1.
[3] *The Value Line Investment Survey*, August 2, August 23, and September 20, 2013.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130140-EI EXHIBIT 73
PARTY Federal Executive Agencies (FEA) Direct
DESCRIPTION Michael P. Gorman (MPG-7)
DATE

Gulf Power Company

Electricity Sales Are Linked to U.S. Economic Growth



Note:
1988 represents the base year. Graph depicts increases or decreases from the base year.

Sources:
U.S. Department of Energy, Energy Information Administration.
Edison Electric Institute, http://www.eei.org.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130140-EI EXHIBIT 74
PARTY Federal Executive Agencies (FEA) Direct
DESCRIPTION Michael P. Gorman (MPG-8)
DATE

Gulf Power Company

Multi-Stage Growth DCF Model

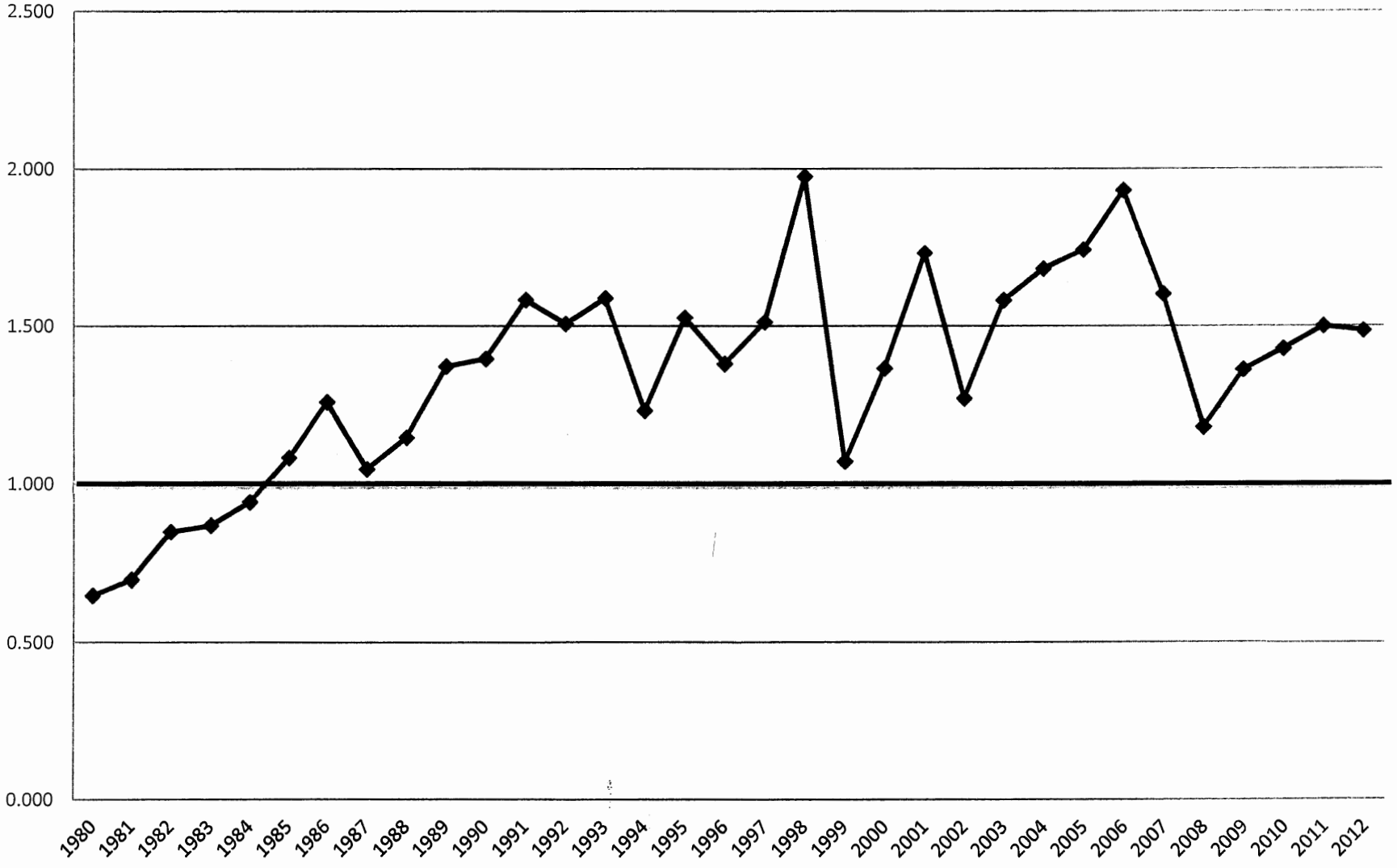
Line	Company	13-Week AVG Stock Price[1] (1)	Annualized Dividend[2] (2)	First Stage Growth[3] (3)	Second Stage Growth Year 6 (4)	Year 7 (5)	Year 8 (6)	Year 9 (7)	Year 10 (8)	Third Stage Growth[4] (9)	Multi-Stage Growth DCF (10)
1	ALLETE, Inc.	$49.75	$1.90	6.00%	5.82%	5.63%	5.45%	5.27%	5.08%	4.90%	9.19%
2	Alliant Energy Corporation	$50.99	$1.88	5.02%	5.00%	4.98%	4.96%	4.94%	4.92%	4.90%	8.80%
3	American Electric Power Company, Inc.	$44.48	$1.96	3.98%	4.13%	4.28%	4.44%	4.59%	4.75%	4.90%	9.26%
4	Black Hills Corporation	$50.38	$1.52	4.33%	4.43%	4.52%	4.62%	4.71%	4.81%	4.90%	7.94%
5	CenterPoint Energy, Inc.	$23.76	$0.83	4.83%	4.84%	4.86%	4.87%	4.88%	4.89%	4.90%	8.55%
6	CMS Energy Corporation	$27.19	$1.02	5.84%	5.68%	5.53%	5.37%	5.21%	5.06%	4.90%	9.07%
7	Dominion Resources, Inc.	$58.69	$2.25	6.39%	6.14%	5.90%	5.65%	5.40%	5.15%	4.90%	9.31%
8	DTE Energy Company	$67.92	$2.62	4.58%	4.63%	4.69%	4.74%	4.79%	4.85%	4.90%	8.86%
9	Duke Energy Corporation	$68.12	$3.12	3.71%	3.91%	4.11%	4.31%	4.50%	4.70%	4.90%	9.36%
10	Great Plains Energy Inc.	$22.99	$0.87	6.37%	6.13%	5.88%	5.64%	5.39%	5.15%	4.90%	9.25%
11	Hawaiian Electric Industries, Inc.	$25.66	$1.24	2.83%	3.18%	3.52%	3.87%	4.21%	4.56%	4.90%	9.35%
12	Integrys Energy Group, Inc.	$58.74	$2.72	5.17%	5.12%	5.08%	5.03%	4.99%	4.94%	4.90%	9.84%
13	NextEra Energy, Inc.	$82.44	$2.64	6.20%	5.98%	5.76%	5.55%	5.33%	5.12%	4.90%	8.54%
14	Northeast Utilities	$42.25	$1.47	7.71%	7.24%	6.78%	6.31%	5.84%	5.37%	4.90%	9.25%
15	NorthWestern Corporation	$41.31	$1.52	5.25%	5.19%	5.13%	5.08%	5.02%	4.96%	4.90%	8.84%
16	OGE Energy Corp.	$35.88	$0.84	5.16%	5.12%	5.07%	5.03%	4.99%	4.94%	4.90%	7.36%
17	Otter Tail Corporation	$28.67	$1.19	N/A	N/A	N/A	N/A	N/A	N/A	4.90%	N/A
18	Pepco Holdings, Inc.	$19.56	$1.08	4.55%	4.61%	4.66%	4.72%	4.78%	4.84%	4.90%	10.57%
19	Pinnacle West Capital Corporation	$55.98	$2.18	4.64%	4.68%	4.72%	4.77%	4.81%	4.86%	4.90%	8.92%
20	PNM Resources, Inc.	$22.69	$0.66	7.33%	6.93%	6.52%	6.12%	5.71%	5.31%	4.90%	8.46%
21	Portland General Electric Company	$30.07	$1.10	6.01%	5.82%	5.64%	5.45%	5.27%	5.08%	4.90%	9.01%
22	SCANA Corporation	$49.41	$2.03	4.61%	4.66%	4.71%	4.76%	4.80%	4.85%	4.90%	9.13%
23	Sempra Energy	$84.27	$2.52	3.58%	3.80%	4.02%	4.24%	4.46%	4.68%	4.90%	7.76%
24	Southern Company	$43.21	$2.03	4.36%	4.45%	4.54%	4.63%	4.72%	4.81%	4.90%	9.67%
25	Vectren Corporation	$34.39	$1.42	5.00%	4.98%	4.97%	4.95%	4.93%	4.92%	4.90%	9.26%
26	Westar Energy, Inc.	$31.97	$1.36	2.79%	3.14%	3.49%	3.85%	4.20%	4.55%	4.90%	8.80%
27	Wisconsin Energy Corporation	$41.57	$1.53	5.30%	5.23%	5.16%	5.10%	5.03%	4.97%	4.90%	8.86%
28	Xcel Energy Inc.	$28.57	$1.12	4.66%	4.70%	4.74%	4.78%	4.82%	4.86%	4.90%	8.95%
29	**Average**	**$43.60**	**$1.66**	**5.04%**	**5.02%**	**5.00%**	**4.97%**	**4.95%**	**4.92%**	**4.90%**	**8.97%**
30	**Median**										**9.01%**

Sources:
[1] SNL Financial, Downloaded on September 25, 2013
[2] *The Value Line Investment Survey*, August 2, August 23, and September 20, 2013.
[3] Exhibit MPG-4.
[4] *Blue Chip Financial Forecasts,* June 1, 2013 at 14.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130140-EI EXHIBIT 75
PARTY Federal Executive Agencies (FEA) Direct
DESCRIPTION Michael P. Gorman (MPG-9)
DATE

Gulf Power Company

Common Stock Market/Book Ratio



FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130140-EI EXHIBIT 76
PARTY Federal Executive Agencies (FEA) Direct
DESCRIPTION Michael P. Gorman (MPG-10)

Gulf Power Company

Equity Risk Premium - Treasury Bond

Line	Year	Authorized Electric Returns[1] (1)	Treasury Bond Yield[2] (2)	Indicated Risk Premium (3)
1	1986	13.93%	7.80%	6.13%
2	1987	12.99%	8.58%	4.41%
3	1988	12.79%	8.96%	3.83%
4	1989	12.97%	8.45%	4.52%
5	1990	12.70%	8.61%	4.09%
6	1991	12.55%	8.14%	4.41%
7	1992	12.09%	7.67%	4.42%
8	1993	11.41%	6.60%	4.81%
9	1994	11.34%	7.37%	3.97%
10	1995	11.55%	6.88%	4.67%
11	1996	11.39%	6.70%	4.69%
12	1997	11.40%	6.61%	4.79%
13	1998	11.66%	5.58%	6.08%
14	1999	10.77%	5.87%	4.90%
15	2000	11.43%	5.94%	5.49%
16	2001	11.09%	5.49%	5.60%
17	2002	11.16%	5.43%	5.73%
18	2003	10.97%	4.96%	6.01%
19	2004	10.75%	5.05%	5.70%
20	2005	10.54%	4.65%	5.89%
21	2006	10.36%	4.99%	5.37%
22	2007	10.36%	4.83%	5.53%
23	2008	10.46%	4.28%	6.18%
24	2009	10.48%	4.07%	6.41%
25	2010	10.34%	4.25%	6.09%
26	2011	10.22%	3.91%	6.31%
27	2012	10.00%	2.92%	7.08%
28	2013 [3]	9.80%	3.14%	6.66%
29	**Average**	**11.34%**	**5.99%**	**5.35%**

Sources:

[1] Regulatory Research Associates, Inc., *Regulatory Focus,* Jan. 85 - Dec. 06, and July 9, 2013, excluding the VA cases, which are subject to a 200 basis point adjustment for certain generation assets.

[2] St. Louis Federal Reserve: Economic Research, http://research.stlouisfed.org/. The yields from 2002 to 2005 represent the 20-Year Treasury yields obtained from the Federal Reserve Bank.

[3] The data includes the period Jan - Jun 2013.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130140-EI EXHIBIT 77
PARTY Federal Executive Agencies (FEA) Direct
DESCRIPTION Michael P. Gorman (MPG-11)

Gulf Power Company

Equity Risk Premium - Utility Bond

Line	Year	Authorized Electric Returns[1] (1)	Average "A" Rated Utility Bond Yield[2] (2)	Indicated Risk Premium (3)
1	1986	13.93%	9.58%	4.35%
2	1987	12.99%	10.10%	2.89%
3	1988	12.79%	10.49%	2.30%
4	1989	12.97%	9.77%	3.20%
5	1990	12.70%	9.86%	2.84%
6	1991	12.55%	9.36%	3.19%
7	1992	12.09%	8.69%	3.40%
8	1993	11.41%	7.59%	3.82%
9	1994	11.34%	8.31%	3.03%
10	1995	11.55%	7.89%	3.66%
11	1996	11.39%	7.75%	3.64%
12	1997	11.40%	7.60%	3.80%
13	1998	11.66%	7.04%	4.62%
14	1999	10.77%	7.62%	3.15%
15	2000	11.43%	8.24%	3.19%
16	2001	11.09%	7.76%	3.33%
17	2002	11.16%	7.37%	3.79%
18	2003	10.97%	6.58%	4.39%
19	2004	10.75%	6.16%	4.59%
20	2005	10.54%	5.65%	4.89%
21	2006	10.36%	6.07%	4.29%
22	2007	10.36%	6.07%	4.29%
23	2008	10.46%	6.53%	3.93%
24	2009	10.48%	6.04%	4.44%
25	2010	10.34%	5.46%	4.88%
26	2011	10.22%	5.04%	5.18%
27	2012	10.00%	4.13%	5.87%
28	2013 [3]	9.80%	4.20%	5.60%
29	**Average**	**11.34%**	**7.39%**	**3.95%**

Sources:

[1] Regulatory Research Associates, Inc., *Regulatory Focus,* Jan. 85 - Dec. 06, and July 9, 2013, excluding the VA cases, which are subject to a 200 basis point adjustment for certain generation assets.

[2] Mergent Public Utility Manual, Mergent Weekly News Reports, 2003. The utility yields for the period 2001-2009 were obtained from the Mergent Bond Record. The utility yields from 2010-2013 were obtained from http://credittrends.moodys.com/.

[3] The data includes the period Jan - Jun 2013.

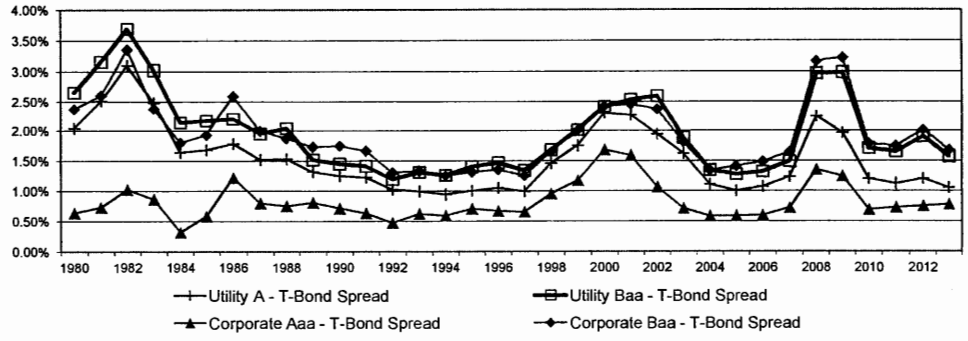
FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130140-EI EXHIBIT 78
PARTY Federal Executive Agencies (FEA) Direct
DESCRIPTION Michael P. Gorman (MPG-12)

Gulf Power Company

Bond Yield Spreads

Line	Year	T-Bond Yield[1] (1)	Public Utility Bond A[2] (2)	Public Utility Bond Baa[2] (3)	Public Utility Bond A-T-Bond Spread (4)	Public Utility Bond Baa-T-Bond Spread (5)	Corporate Bond Aaa[1] (6)	Corporate Bond Baa[1] (7)	Corporate Bond Aaa-T-Bond Spread (8)	Corporate Bond Baa-T-Bond Spread (9)	Utility to Corporate Baa Spread (10)	Utility to Corporate A-Aaa Spread (11)
1	1980	11.30%	13.34%	13.95%	2.04%	2.65%	11.94%	13.67%	0.64%	2.37%	0.28%	1.40%
2	1981	13.44%	15.95%	16.60%	2.51%	3.16%	14.17%	16.04%	0.73%	2.60%	0.56%	1.78%
3	1982	12.76%	15.86%	16.45%	3.10%	3.69%	13.79%	16.11%	1.03%	3.35%	0.34%	2.07%
4	1983	11.18%	13.66%	14.20%	2.48%	3.02%	12.04%	13.55%	0.86%	2.38%	0.65%	1.62%
5	1984	12.39%	14.03%	14.53%	1.64%	2.14%	12.71%	14.19%	0.32%	1.80%	0.34%	1.32%
6	1985	10.79%	12.47%	12.96%	1.68%	2.17%	11.37%	12.72%	0.58%	1.93%	0.24%	1.10%
7	1986	7.80%	9.58%	10.00%	1.78%	2.20%	9.02%	10.39%	1.22%	2.59%	-0.39%	0.56%
8	1987	8.58%	10.10%	10.53%	1.52%	1.95%	9.38%	10.58%	0.80%	2.00%	-0.05%	0.72%
9	1988	8.96%	10.49%	11.00%	1.53%	2.04%	9.71%	10.83%	0.75%	1.87%	0.17%	0.78%
10	1989	8.45%	9.77%	9.97%	1.32%	1.52%	9.26%	10.18%	0.81%	1.73%	-0.21%	0.51%
11	1990	8.61%	9.86%	10.06%	1.25%	1.45%	9.32%	10.36%	0.71%	1.75%	-0.29%	0.54%
12	1991	8.14%	9.36%	9.55%	1.22%	1.41%	8.77%	9.80%	0.63%	1.67%	-0.25%	0.59%
13	1992	7.67%	8.69%	8.86%	1.02%	1.19%	8.14%	8.98%	0.47%	1.31%	-0.12%	0.55%
14	1993	6.60%	7.59%	7.91%	0.99%	1.31%	7.22%	7.93%	0.62%	1.33%	-0.02%	0.37%
15	1994	7.37%	8.31%	8.63%	0.94%	1.26%	7.96%	8.62%	0.59%	1.25%	0.01%	0.35%
16	1995	6.88%	7.89%	8.29%	1.01%	1.41%	7.59%	8.20%	0.71%	1.32%	0.09%	0.30%
17	1996	6.70%	7.75%	8.17%	1.05%	1.47%	7.37%	8.05%	0.67%	1.35%	0.12%	0.38%
18	1997	6.61%	7.60%	7.95%	0.99%	1.34%	7.26%	7.86%	0.66%	1.26%	0.09%	0.34%
19	1998	5.58%	7.04%	7.26%	1.46%	1.68%	6.53%	7.22%	0.95%	1.64%	0.04%	0.51%
20	1999	5.87%	7.62%	7.88%	1.75%	2.01%	7.04%	7.87%	1.18%	2.01%	0.01%	0.58%
21	2000	5.94%	8.24%	8.36%	2.30%	2.42%	7.62%	8.36%	1.68%	2.42%	-0.01%	0.62%
22	2001	5.49%	7.76%	8.03%	2.27%	2.54%	7.08%	7.95%	1.59%	2.45%	0.08%	0.68%
23	2002	5.43%	7.37%	8.02%	1.94%	2.59%	6.49%	7.80%	1.06%	2.37%	0.22%	0.88%
24	2003	4.96%	6.58%	6.84%	1.62%	1.89%	5.67%	6.77%	0.71%	1.81%	0.08%	0.91%
25	2004	5.05%	6.16%	6.40%	1.11%	1.35%	5.63%	6.39%	0.58%	1.35%	0.00%	0.53%
26	2005	4.65%	5.65%	5.93%	1.00%	1.28%	5.24%	6.06%	0.59%	1.42%	-0.14%	0.41%
27	2006	4.99%	6.07%	6.32%	1.08%	1.32%	5.59%	6.48%	0.60%	1.49%	-0.16%	0.48%
28	2007	4.83%	6.07%	6.33%	1.24%	1.50%	5.56%	6.48%	0.72%	1.65%	-0.15%	0.52%
29	2008	4.28%	6.53%	7.25%	2.25%	2.97%	5.63%	7.45%	1.35%	3.17%	-0.20%	0.90%
30	2009	4.07%	6.04%	7.06%	1.97%	2.99%	5.31%	7.30%	1.24%	3.23%	-0.24%	0.72%
31	2010	4.25%	5.46%	5.96%	1.21%	1.71%	4.94%	6.04%	0.69%	1.79%	-0.08%	0.52%
32	2011	3.91%	5.04%	5.56%	1.13%	1.65%	4.64%	5.66%	0.73%	1.75%	-0.10%	0.40%
33	2012	2.92%	4.13%	4.83%	1.21%	1.91%	3.67%	4.94%	0.75%	2.01%	-0.11%	0.46%
34	2013[3]	3.14%	4.20%	4.72%	1.06%	1.58%	3.92%	4.82%	0.78%	1.68%	-0.10%	0.28%
35	**Average**	**7.05%**	**8.60%**	**9.01%**	**1.55%**	**1.96%**	**7.87%**	**8.99%**	**0.82%**	**1.94%**	**0.02%**	**0.73%**

Yield Spreads
Treasury Vs. Corporate & Treasury Vs. Utility



Sources:

[1] St. Louis Federal Reserve: Economic Research, http://research.stlouisfed.org/.

[2] Mergent Public Utility Manual, Mergent Weekly News Reports, 2003. The utility yields for the period 2001-2009 were obtained from the Mergent Bond Record. The utility yields from 2010-2012 were obtained from http://credittrends.moodys.com/.

[3] The data includes the period Jan - Jun 2013.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130140-EI EXHIBIT 79
PARTY Federal Executive Agencies (FEA) Direct
DESCRIPTION Michael P. Gorman (MPG-13)

Gulf Power Company

Treasury and Utility Bond Yields

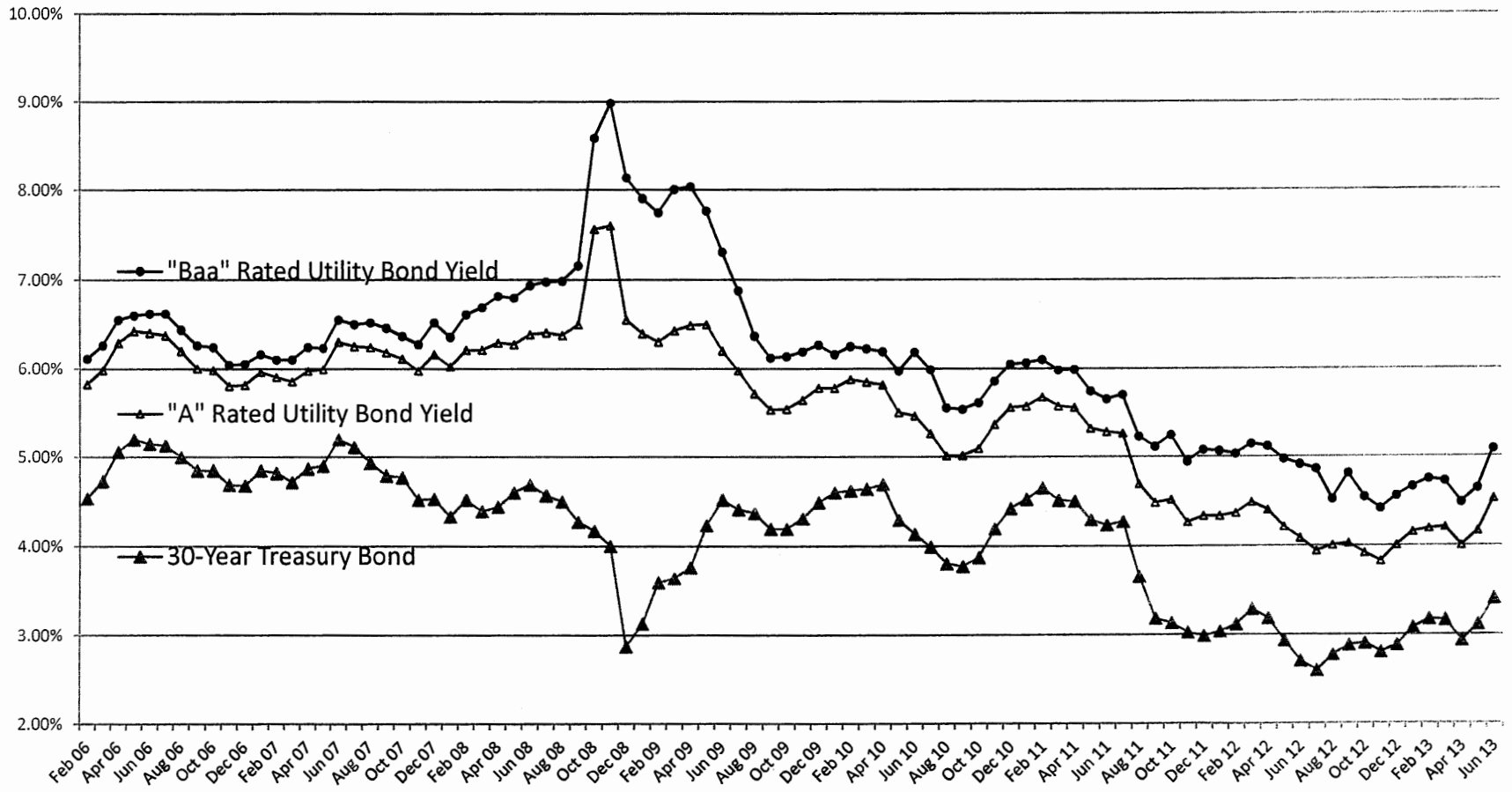
Line	Date	Treasury Bond Yield[1] (1)	"A" Rated Utility Bond Yield[2] (2)	"Baa" Rated Utility Bond Yield[2] (3)
1	09/20/13	3.77%	4.79%	5.27%
2	09/13/13	3.84%	4.85%	5.37%
3	09/06/13	3.87%	4.86%	5.37%
4	08/30/13	3.70%	4.67%	5.17%
5	08/23/13	3.80%	4.79%	5.32%
6	08/16/13	3.86%	4.83%	5.39%
7	08/09/13	3.63%	4.61%	5.17%
8	08/02/13	3.69%	4.63%	5.18%
9	07/26/13	3.61%	4.62%	5.13%
10	07/19/13	3.56%	4.62%	5.12%
11	07/12/13	3.64%	4.76%	5.28%
12	07/05/13	3.68%	4.82%	5.38%
13	06/28/13	3.52%	4.67%	5.23%
14	**Average**	**3.71%**	**4.73%**	**5.26%**
15	**Spread To Treasury**		**1.02%**	**1.55%**

Sources:
[1] St. Louis Federal Reserve: Economic Research, http://research.stlouisfed.org.
[2]http://credittrends.moodys.com/.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130140-EI EXHIBIT 80
PARTY Federal Executive Agencies (FEA) Direct
DESCRIPTION Michael P. Gorman (MPG-14)
DATE

Gulf Power Company

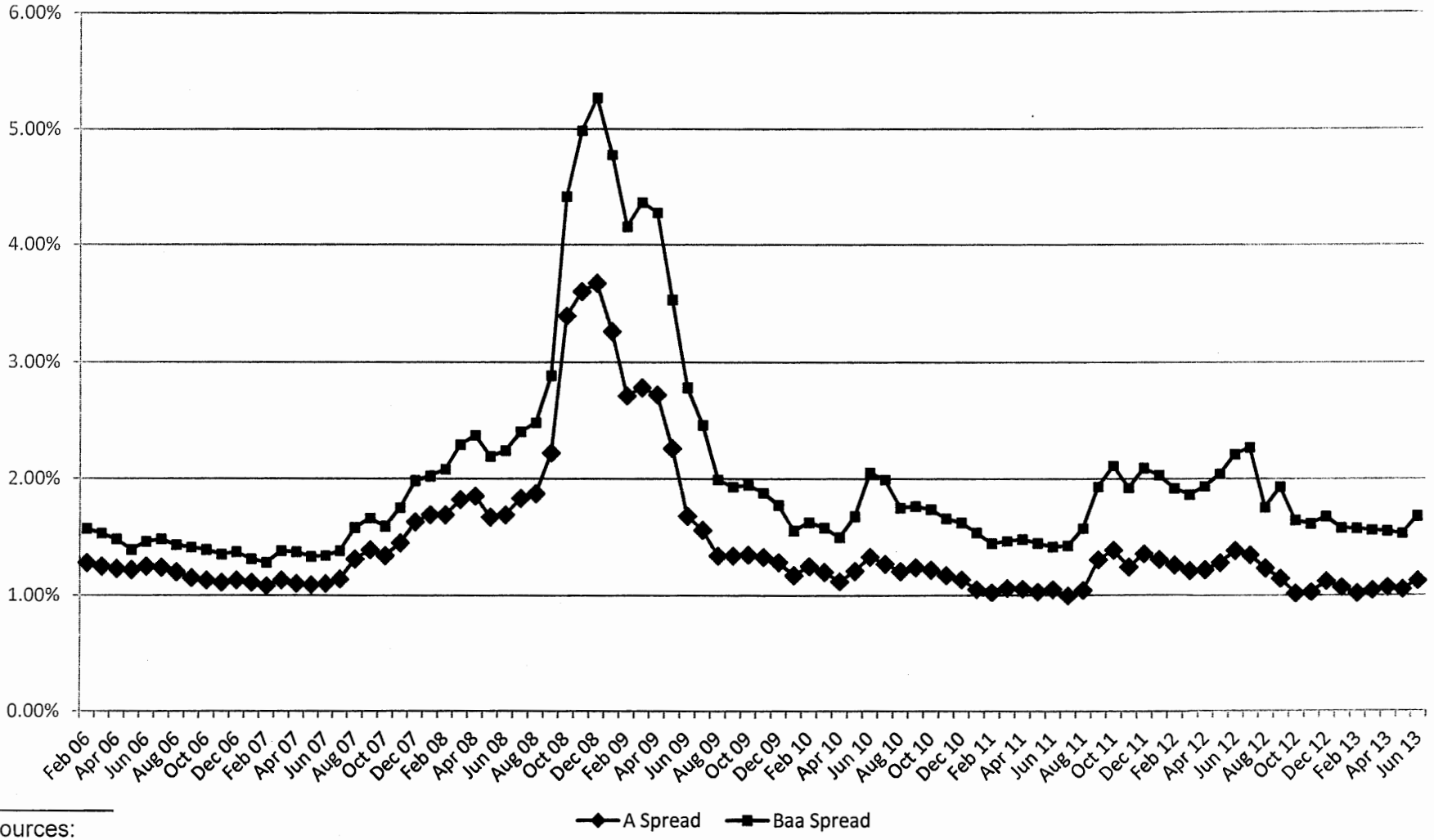
Trends in Bond Yields



Sources:
Merchant Bond Record.
www.moodys.com, Bond Yields and Key Indicators.
St. Louis Federal Reserve: Economic Research, http://research.stlouisfed.org/

Gulf Power Company

Yield Spread Between Utility Bonds and 30-Year Treasury Bonds



Sources:
Merchant Bond Record.
www.moodys.com, Bond Yields and Key Indicators.
St. Louis Federal Reserve: Economic Research, http://research.stlouisfed.org/

Gulf Power Company

Value Line Beta

Line	Company	Beta
1	ALLETE, Inc.	0.70
2	Alliant Energy Corporation	0.75
3	American Electric Power Company, Inc.	0.70
4	Black Hills Corporation	0.80
5	CenterPoint Energy, Inc.	0.80
6	CMS Energy Corporation	0.75
7	Dominion Resources, Inc.	0.70
8	DTE Energy Company	0.75
9	Duke Energy Corporation	0.60
10	Great Plains Energy Inc.	0.80
11	Hawaiian Electric Industries, Inc.	0.70
12	Integrys Energy Group, Inc.	0.90
13	NextEra Energy, Inc.	0.70
14	Northeast Utilities	0.75
15	NorthWestern Corporation	0.70
16	OGE Energy Corp.	0.75
17	Otter Tail Corporation	0.90
18	Pepco Holdings, Inc.	0.75
19	Pinnacle West Capital Corporation	0.70
20	PNM Resources, Inc.	0.95
21	Portland General Electric Company	0.75
22	SCANA Corporation	0.65
23	Sempra Energy	0.80
24	Southern Company	0.55
25	Vectren Corporation	0.75
26	Westar Energy, Inc.	0.75
27	Wisconsin Energy Corporation	0.65
28	Xcel Energy Inc.	0.60
29	**Average**	**0.74**

Source:
The Value Line Investment Survey,
August 2, August 23, and September 20, 2013.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130140-EI
PARTY
DESCRIPTION Michael P. Gorman (MPG-15)
DATE
EXHIBIT 81
Federal Executive Agencies (FEA) Direct

Gulf Power Company

CAPM Return

Line	Description	Market Risk Premium
1	Risk-Free Rate[1]	4.20%
2	Risk Premium[2]	6.70%
3	Beta[3]	0.74
4	**CAPM**	**9.14%**

Sources:

[1] *Blue Chip Financial Forecasts*; September 1, 2013, at 2.

[2] Morningstar, Inc. *Ibbotson SBBI 2013 Classic Yearbook* at 88, and Morningstar, Inc. *Ibbotson SBBI 2013 Valuation Yearbook* at 54 and 66.

[3] Exhibit MPG-15

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130140-EI EXHIBIT 82
PARTY Federal Executive Agencies (FEA) Direct
DESCRIPTION Michael P. Gorman (MPG-16)
DATE

Gulf Power Company

Standard & Poor's Credit Metrics

Line	Description	Retail Cost of Service Amount (1)	S&P Benchmark[1/2] Significant (2)	S&P Benchmark[1/2] Significant (3)	Reference (4)
1	Rate Base	$ 1,883,901			Schedule A-1.
2	Weighted Common Return	4.49%			Page 2, Line 4, Col. 4.
3	Pre-Tax Rate of Return	9.91%			Page 2, Line 5, Col. 5.
4	Income to Common	$ 84,495			Line 1 x Line 2.
5	EBIT	$ 186,754			Line 1 x Line 3.
6	Depreciation & Amortization	$ 104,505			Schedule C-1.
7	Imputed Amortization	$ 9,385			Page 4, Line 11, Col. 1.
8	Deferred Income Taxes & ITC	$ 12,686			Schedule C-1.
9	Funds from Operations (FFO)	$ 211,071			Sum of Line 4 and Lines 6 through 8.
10	Imputed Interest Expense	$ 1,313			Page 4, Line 10, Col. 1.
11	EBITDA	$ 301,957			Sum of Lines 5 through 7 and Line 10.
12	Total Debt Ratio	47%	45% - 50%	50% - 60%	Page 3, Line 4, Col. 2.
13	Debt to EBITDA	3.0x	3.0x - 4.0x	4.0x - 5.0x	(Line 1 x Line 12) / Line 11.
14	FFO to Total Debt	24%	20% - 30%	12% - 20%	Line 9 / (Line 1 x Line 12).

Sources:
[1] Standard & Poor's: "Criteria Methodology: Business Risk/Financial Risk Matrix Expanded," May 27, 2009.
[2] *S&P RatingsDirect:* "U.S. Regulated Electric Utilities, Strongest to Weakest," July 30, 2013.

Note:
Based on the July 2013 S&P metrics, Gulf Power has an "Excellent" business profile and a "Significant" financial profile.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130140-EI EXHIBIT 83
PARTY Federal Executive Agencies (FEA) Direct
DESCRIPTION Michael P. Gorman (MPG-17)
DATE

Gulf Power Company

Standard & Poor's Credit Metrics
(Pre-Tax Rate of Return)

Line	Description	Amount (000) (1)	Weight (2)	Cost (3)	Weighted Cost (4)	Pre-Tax Weighted Cost (5)
1	Long-Term Debt	$ 567,191	45.46%	4.96%	2.25%	2.25%
2	Short-Term Debt	$ 22,865	1.83%	0.82%	0.02%	0.02%
3	Preferrence Stock	$ 65,481	5.25%	6.00%	0.31%	0.31%
4	Common Equity	$ 592,193	47.46%	**9.45%**	4.49%	7.33%
5	**Total**	**$ 1,247,730**	**100.00%**		**7.07%**	**9.91%**
6	Tax Conversion Factor*					1.6340

Sources:
Exhibit MPG-1.
* Schedule A-1.

Gulf Power Company

Standard & Poor's Credit Metrics
(Financial Capital Structure)

Line	Description	Amount (000) (1)	Weight (2)
1	Long-Term Debt	$ 567,191	45.41%
2	Short-Term Debt	$ 22,865	1.83%
3	Off Balance Sheet Debt*	$ 1,276	0.10%
4	**Total Debt**	**$ 591,332**	**47.34%**
5	Preferrence Stock	$ 65,481	5.24%
6	Common Equity	$ 592,193	47.41%
7	**Total**	**$ 1,249,006**	**100.00%**

Sources:
Exhibit MPG-1.

Gulf Power Company

Standard & Poor's Credit Metrics
(Off-Balance Sheet Debt)

Line	Description	Amount (000) (1)	Reference (2)
	Jurisdictional Allocator		
1	Jurisdictional Rate Base	$ 1,883,901	Schedule B-1.
2	Total Company Rate Base	1,919,769	Schedule B-1.
3	Allocation Factor	0.981317	Line 1 / Line 2.
	Total Company[1]		
4	Operating Leases	$ 812	
5	Imputed Interest Expense	$ 38	
6	Imputed Amortization Expense	$ 372	
7	Purchase Power Agreements	$ 465	
8	Imputed Interest Expense	$ 1,300	
9	Imputed Amortization Expense	$ 9,191	
	Jurisdiction Allocation		
10	Imputed Interest Expense	$ 1,313	Line 4 * Lines 6 and 9.
11	Imputed Amortization Expense	$ 9,385	Line 4 * Lines 7 and 10.

Source:
[1] *Standard & Poor's RatingsDirect,* "Gulf Power Co.," September 28, 2011 at 5.

Gulf Power Company

Accuracy of Interest Rate Forecasts
(Long-Term Treasury Bond Yields - Projected Vs. Actual)

Line	Date	Publication Data: Prior Quarter Actual Yield (1)	Publication Data: Projected Yield (2)	Publication Data: Projected Quarter (3)	Actual Yield in Projected Quarter (4)	Projected Yield Higher (Lower) Than Actual Yield* (5)
1	Dec-00	5.8%	5.8%	1Q, 02	5.6%	0.2%
2	Mar-01	5.7%	5.6%	2Q, 02	5.8%	-0.2%
3	Jun-01	5.4%	5.8%	3Q, 02	5.2%	0.6%
4	Sep-01	5.7%	5.9%	4Q, 02	5.1%	0.8%
5	Dec-01	5.5%	5.7%	1Q, 03	5.0%	0.7%
6	Mar-02	5.3%	5.9%	2Q, 03	4.7%	1.2%
7	Jun-02	5.6%	6.2%	3Q, 03	5.2%	1.0%
8	Sep-02	5.8%	5.9%	4Q, 03	5.2%	0.7%
9	Dec-02	5.2%	5.7%	1Q, 04	4.9%	0.8%
10	Mar-03	5.1%	5.7%	2Q, 04	5.4%	0.3%
11	Jun-03	5.0%	5.4%	3Q, 04	5.1%	0.3%
12	Sep-03	4.7%	5.8%	4Q, 04	4.9%	0.9%
13	Dec-03	5.2%	5.9%	1Q, 05	4.8%	1.1%
14	Mar-04	5.2%	5.9%	2Q, 05	4.6%	1.4%
15	Jun-04	4.9%	6.2%	3Q, 05	4.5%	1.7%
16	Sep-04	5.4%	6.0%	4Q, 05	4.8%	1.2%
17	Dec-04	5.1%	5.8%	1Q, 06	4.6%	1.2%
18	Mar-05	4.9%	5.6%	2Q, 06	5.1%	0.5%
19	Jun-05	4.8%	5.5%	3Q, 06	5.0%	0.5%
20	Sep-05	4.6%	5.2%	4Q, 06	4.7%	0.5%
21	Dec-05	4.5%	5.3%	1Q, 07	4.8%	0.5%
22	Mar-06	4.8%	5.1%	2Q, 07	5.0%	0.1%
23	Jun-06	4.6%	5.3%	3Q, 07	4.9%	0.4%
24	Sep-06	5.1%	5.2%	4Q, 07	4.6%	0.6%
25	Dec-06	5.0%	5.0%	1Q, 08	4.4%	0.6%
26	Mar-07	4.7%	5.1%	2Q, 08	4.6%	0.5%
27	Jun-07	4.8%	5.1%	3Q, 08	4.5%	0.7%
28	Sep-07	5.0%	5.2%	4Q, 08	3.7%	1.5%
29	Dec-07	4.9%	4.8%	1Q, 09	3.5%	1.4%
30	Mar-08	4.6%	4.8%	2Q, 09	4.0%	0.8%
31	Jun-08	4.4%	4.9%	3Q, 09	4.3%	0.6%
32	Sep-08	4.6%	5.1%	4Q, 09	4.3%	0.8%
33	Dec-08	4.5%	4.6%	1Q, 10	4.6%	0.0%
34	Mar-09	3.7%	4.1%	2Q, 10	4.4%	-0.3%
35	Jun-09	3.5%	4.6%	3Q, 10	3.9%	0.8%
36	Sep-09	4.0%	5.0%	4Q, 10	4.2%	0.8%
37	Dec-09	4.3%	5.0%	1Q, 11	4.6%	0.4%
38	Mar-10	4.3%	5.2%	2Q, 11	4.3%	0.9%
39	Jun-10	4.6%	5.2%	3Q, 11	3.7%	1.5%
40	Sep-10	4.4%	4.7%	4Q, 11	3.0%	1.7%
41	Dec-10	3.9%	4.6%	1Q, 12	3.1%	1.5%
42	Mar-11	4.2%	5.1%	2Q, 12	2.9%	2.2%
43	Jun-11	4.6%	5.2%	3Q, 12	2.8%	2.5%
44	Sep-11	4.3%	4.2%	4Q, 12	2.9%	1.3%
45	Dec-11	3.7%	3.8%	1Q, 13	3.1%	0.7%
46	Mar-12	3.0%	3.8%	2Q, 13	3.2%	0.7%
47	Apr-12	3.1%	3.9%	3Q, 13		
48	May-12	3.1%	3.9%	3Q, 13		
49	Jun-12	3.1%	3.7%	3Q, 13		
50	Jul-12	2.9%	3.6%	4Q, 13		
51	Aug-12	2.9%	3.4%	4Q, 13		
52	Sep-12	2.9%	3.4%	4Q, 13		
53	Oct-12	2.8%	3.4%	1Q, 14		
54	Nov-12	2.8%	3.4%	1Q, 14		
55	Dec-12	2.8%	3.4%	1Q, 14		
56	Jan-13	2.9%	3.4%	2Q, 14		
57	Feb-13	2.9%	3.5%	2Q, 14		
58	Mar-13	2.9%	3.6%	2Q, 14		
59	Apr-13	3.1%	3.7%	3Q, 14		
60	May-13	3.1%	3.7%	3Q, 14		
61	Jun-13	3.1%	3.7%	3Q, 14		
62	Jul-13	3.1%	4.0%	4Q, 14		
63	Aug-13	3.2%	4.1%	4Q, 14		
64	Sep-13	3.2%	4.2%	4Q, 14		

Source:
Blue Chip Financial Forecasts, Various Dates.
* Col. 2 - Col. 4.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130140-EI EXHIBIT 84
PARTY Federal Executive Agencies (FEA) Direct
DESCRIPTION Michael P. Gorman (MPG-18)
DATE